Revised Draft
Gas and Hydrogen Network Development Plan 2025

01.06.2026

Legal notice

Revised Draft Gas and Hydrogen Network Development Plan 2025

Contacts:
Stefan Mellahn, Nils von Ohlen
Coordination Office for Gas and Hydrogen Network Development Planning
c/o FNB Gas e.V.
Georgenstraße 23, 10117 Berlin
http://ko-nep.de/

Disclaimer

This document is a translation from the German original; the binding version is exclusively the document of the Draft Gas and Hydrogen Network Development Plan 2025 in its German version.

The German gas transmission system operators and the regulated hydrogen transmission system operators have prepared this document exclusively to comply with their obligations under Sections 15a et seq. of the German Energy Industry Act (EnWG). The gas transmission system operators do not provide any guarantee for the accuracy, topicality, completeness or quality of the content and information provided by third parties or for their own statements on future developments and forecasts which, by their very nature, are inherently uncertain. The gas transmission system operators will not accept any liability for any damage caused directly or indirectly by the use of the information provided.

Transmission network operators

AquaDuctus Pipeline GmbH
Kölnische Straße 108–112, 34119 Kassel
https://aquaductus-offshore.de/

bayernets GmbH
Poccistraße 7, 80336 Munich
www.bayernets.de

Ferngas Netzgesellschaft mbH
Reichswaldstraße 52, 90571 Schwaig
www.ferngas.de

Fluxys Deutschland GmbH
Elisabethstraße 5, 40217 Düsseldorf
www.fluxys.com

Fluxys TENP GmbH
Elisabethstraße 5, 40217 Düsseldorf
www.fluxys.com

GASCADE Gastransport GmbH
Kölnische Straße 108–112, 34119 Kassel
www.gascade.de

Gastransport Nord GmbH
Cloppenburger Straße 363, 26133 Oldenburg
www.gtg-nord.de

Gasunie Deutschland Transport Services GmbH
Pasteurallee 1, 30655 Hanover
www.gasunie.de

Lubmin-Brandov Gastransport GmbH
Huttropstraße 60, 45138 Essen
www.lbtg.de

NaTran Deutschland GmbH
Rosenthaler Straße 40/41, 10178 Berlin
www.natran-deutschland.de

NEL Gastransport GmbH
Kölnische Straße 108–112, 34119 Kassel
www.nel-gastransport.de

Nowega GmbH
Anton-Bruchausen-Straße 4, 48147 Münster
www.nowega.de

ONTRAS Gastransport GmbH
Maximilianallee 4, 04129 Leipzig
www.ontras.com

Open Grid Europe GmbH
Kallenbergstraße 5, 45141 Essen
www.oge.net

terranets bw GmbH
Am Wallgraben 135, 70565 Stuttgart
www.terranets-bw.de

Thyssengas GmbH
Emil-Moog-Platz 13, 44137 Dortmund
www.thyssengas.com

Thyssengas H2 GmbH
Emil-Moog-Platz 13, D-44137 Dortmund
www.thyssengas.com

Table of contents

List of figures

List of tables

Executive Summary

Executive Summary

The transition to climate neutrality requires a joint approach to methane and hydrogen as energy sources. For this reason, the 2024 amendment of the German Energy Industry Act calls for the integrated planning of both infrastructures. This revised draft of the Gas and Hydrogen Network Development Plan 2025 provides an overview of the integrated network planning activities undertaken by the gas transmission system operators and regulated hydrogen transmission system operators to ensure compliance with statutory requirements.

Gas and Hydrogen Network Development Plan 2025 based on the approved Scenario Framework

The Gas and Hydrogen Network Development Plan 2025 is based on the Scenario Framework (ref. no. 4.13.01/11#1) developed by the gas transmission system operators (TSOs) and approved, subject to amendments, by the Federal Network Agency on 30 April 2025. In addition to the three scenarios stipulated for the first time in the Energy Industry Act, which describe the range of probable developments in the context of the German government's climate and energy policy targets for the years 2037 and 2045, the Federal Network Agency has also approved a security of supply scenario 2030 for methane as proposed by the transmission system operators. This scenario allows the supply situation to be viewed from a short-term perspective. The approval also sets out the Federal Network Agency's location and capacity demands for electrolysers and power plants.

An important input variable for methane in this Network Development Plan is sufficient freely allocable capacity. In this draft document, the gas TSOs and hydrogen transmission system operators present a methodology for determining the level of freely allocable capacity that takes into account aspects of market demand, security of supply, but also the necessary import diversification and resilience in equal measure. Adjusting the freely allocable capacity to a sufficient level ensures the appropriate use of market-based instruments and network expansion. Flexibility and complete coverage of the freely allocable capacity off-takes used are maintained even after the freely allocable entry capacity has been reduced. Even when network loads are high, simultaneous demand can be met and there is no capacity shortfall. The level of freely allocable capacity deemed sufficient is published in the Gas NDP database for the auction-relevant period until 2033.

Hydrogen core network review

The Germany-wide hydrogen core network for 2032 spanning 9,040 km was approved by the Federal Network Agency on 22 October 2024. Pursuant to Section 28q (8) of the German Energy Industry Act, core network measures scheduled for commissioning after 31 December 2027 will be reviewed in the Gas and Hydrogen Network Development Plan 2025 to establish if they are necessary. Core network measures already underway by 31 December 2025 and scheduled for commissioning before 31 December 2027 as part of the core network approval will no longer be reviewed and are therefore considered starter network measures. As part of the review of the core network measures, the commissioning dates for some measures were adjusted.

Additions to the revised draft of the Gas and Hydrogen Network Development Plan 2025

As previously announced, the gas TSOs and hydrogen transmission system operators have amended the revised draft to include the hydrogen modelling results for the year 2045, the cross-border IP exit analysis for hydrogen for the year 2037, and the modelling of market-based instruments. In addition, specific measures for M&R stations in the hydrogen pipeline network have been set out in detail, which have also been added to the Gas NDP database. The results of the public consultation are presented in the new chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**.

Modelling results: network expansion proposal for methane and hydrogen

The network expansion proposal is derived from the modelling results of the different scenarios based on criteria. It identifies technical measures required for the network across the different scenarios. This approach accommodates the uncertainties regarding the actual development of methane and hydrogen demand as well as the ramp-up of the hydrogen market in terms of both time and place. It also allows the gas TSOs and hydrogen transmission system operators to meet energy and climate policy objectives.

Compared with the draft Gas and Hydrogen Network Development Plan 2025, there has been one significant change to the network expansion proposal. This change concerns the inclusion of the Ellund-Niebüll core network project. During the consultation, numerous responses called for the project to be included in the proposed network expansion. In particular, they referred to the project's rapid progress since the 2024 market consultation, during which it has become considerably more advanced.

The findings on the use of market-based instruments to relieve network bottlenecks show that no expansion measures beyond those included in the proposed network expansion are economically justified. The measures detailed in the network expansion proposal cannot be replaced by MBIs. This lends support to the network expansion proposal for methane and hydrogen put forward by the gas TSOs and hydrogen transmission system operators.

Table 1: Network expansion proposal for methane and hydrogen

Results of the methane network expansion proposal *	
Technical parameters	
Pipelines [km]	672
Compressor capacity [MW]	0
Total investment [billion euros]	**2.9**
- of which network expansion measures from NDP 2022	1.0
- of which natural gas-reinforcing measures from NDP 2022 and core network	1.4
- of which new network expansion measures for power plants and industry	0.4
- of which new natural gas-reinforcing measures	0.2

* rounded figures

Results of hydrogen network expansion proposal*	
Technical parameters	
Compressor capacity [MW]	255
Pipelines [km]	7,040
- of which pipelines to be repurposed [km]	3,658
- of which newly built pipelines [km]	3,196
- of which newly built pipelines (offshore) [km]	186
- For information: Czech-German Hydrogen Interconnector (CGHI)** [km]	168
Total investment [billion euros]	**20.3**
Compressor stations	2.0
Pipelines (incl. M&R station costs)	18.3
- of which pipelines to be repurposed	2.5
- of which newly built pipelines	14.0
- of which newly built pipelines (offshore)	1.9

* rounded figures

** CGHI was taken into account in the modelling but is not part of the German hydrogen network.

Source: Coordination Office for Gas and Hydrogen Planning

The network expansion proposal envisages a pipeline length of 672 km and total investments of €2.9 billion for methane and 7,040 km and around €20.3 billion for hydrogen by 2037 (plus 2,201 km and €4.0 billion of the originally approved hydrogen core network, which has already been delivered as the starter network or is currently being implemented and is not part of the network expansion proposal). The hydrogen transmission network for 2037 thus roughly corresponds to the scope of the approved hydrogen core network.

Status of implementation of approved measures

The Gas and Hydrogen Network Development Plan 2025 contains information on the status of the approved measures of the most recent Gas Network Development Plan (2022) as well as information on the status of the hydrogen core network (2024).

Updated databases

The Gas NDP database was updated by the Coordination Office for Gas and Hydrogen Network Development Planning as part of the preparation of the current Network Development Plan. It is available to the public at www.nep-gas-datenbank.de and contains information on input variables for modelling, capacities, measures and further details for this Network Development Plan. As part of the revised draft of the Gas and Hydrogen Network Development Plan 2025, the gas TSOs and hydrogen transmission system operators have also populated the new legally mandated network topology database with the network models, consisting of the network topology and the modelled load cases, which were used as the basis for the creation of the Gas and Hydrogen Network Development Plan 2025.

Outlook on the next steps for the Gas and Hydrogen Network Development Plan 2025

The gas TSOs and hydrogen transmission system operators have submitted the consulted and revised draft to the regulatory authority for approval. The Federal Network Agency (BNetzA) will consult on the revised document and will subsequently approve the draft Gas and Hydrogen Network Development Plan submitted by the gas TSOs and regulated hydrogen transmission system operators, taking into account the outcome of the public consultation.

Foreword

Foreword

Dear reader,

With this document, the Coordination Office for Gas and Hydrogen Network Development Planning is submitting the revised draft Gas and Hydrogen Network Development Plan 2025 prepared by the gas TSOs and hydrogen transmission system operators to the Federal Network Agency for review and approval.

This Network Development Plan is a novelty in many respects. The statutory introduction of integrated network development planning for methane and hydrogen networks in 2024 was a significant step towards holistic infrastructure planning for a secure and resilient energy supply. It was accompanied by the greater alignment in terms of timing and content with the transmission system operators' Electricity Network Development Plan. Uniform assumptions now ensure consistent input parameters for power plants and electrolysis sites, so that the planning of electricity, methane and hydrogen networks interlock more effectively and meet the requirements of an increasingly cross-sectoral energy system. In addition, unlike in the past, the modelling for this Network Development Plan was scenario-based for the target years 2037 and 2045.

A particular challenge for gas TSOs and hydrogen transmission system operators was the statutory obligation to review the hydrogen core network approved in October 2024, which took place amid conflicting priorities between the political goal of creating a basis for market development and the existing uncertainties regarding the actual development of methane and hydrogen demand and the temporal and spatial hydrogen market ramp-up. As part of the network expansion proposal for hydrogen based on the scenarios approved in the Scenario Framework, the legal and regulatory options for extending the time frame and making technical adjustments to core network measures were used to implement a cost-effective, Germany-wide, efficient and climate-friendly hydrogen transmission network in line with the market ramp-up.

By the end of 2025, more than 500 kilometres of pipeline of the approved hydrogen core network will have been completed, and further hydrogen projects are currently underway to help decarbonise German industry and the economy and achieve Germany's climate targets.

This version reflects the comments and suggestions made during the public consultation conducted by the gas TSOs and hydrogen transmission system operators from 3 to 27 March 2026.

We would like to thank everyone involved for their excellent cooperation in drawing up this Network Development Plan, namely the market players for participating in the demand and market surveys, and Prognos AG for their support.

Kind regards,

Your KO.NEP – Coordination Office for Gas and Hydrogen Network Development Planning

Introduction

1

1 Introduction

1.1 Legal basis and tasks

The amendment of the Energy Industry Act (EnWG) in 2024 redefined the legal basis for drawing up the network development plan. At the heart of the changes is the requirement for integrated development planning for gas and hydrogen networks. Operators of gas transmission systems and regulated hydrogen transmission system operators therefore have an equal obligation and responsibility to develop their respective plans. This document always distinguishes between methane and hydrogen as energy sources. For methane, the transmission system operators do not make any specific distinction between natural gas, biomethane and other gases.

The amendment of the EnWG reflects the statutory climate targets and the need for a future hydrogen-based energy supply. Since a significant portion of the future hydrogen network will consist of repurposed methane pipelines, the planning of both energy infrastructures will have to be closely coordinated.

Sections 15a–d EnWG create a transparent framework for a binding process that incorporates plans for future gas and hydrogen networks in an integrated approach. In order to facilitate the coordinated and efficient expansion of these central energy infrastructures, the gas transmission system operators (TSOs) and the regulated hydrogen transmission network operators (HTNOs) established a Coordination Office for Gas and Hydrogen Network Development Planning (KO.NEP).

The task of KO.NEP is to coordinate the development of the Scenario Framework and network development plans for gas and hydrogen and to submit these to the Federal Network Agency (BNetzA) every two years. KO.NEP acts as a central point of contact for authorities and market participants on issues relating to network development planning in the methane and hydrogen sector and is also responsible for creating and operating the network topology database for the methane and hydrogen networks.

1.1.1 Gas and Hydrogen Network Development Plan

In accordance with Section 15c (2) EnWG, the Germany-wide Gas and Hydrogen Network Development Plan comprises all effective measures for the needs-based and efficient optimisation, reinforcement and expansion of the networks which are necessary for secure and reliable network operation by the end of the respective observation periods pursuant to Section 15b (2) EnWG at the latest. Measures should be selected with a view to implementing the German government's climate policy objectives and ensuring security of supply, with particular consideration given to the goal of affordability. The conversion of existing pipeline infrastructure to hydrogen generally takes precedence over the construction of new pipelines, provided this is feasible and economically viable.

The Scenario Framework provides the basis for network development planning. It is to consider at least three scenarios for the development of demand, covering a range of probable trends over the next 10 to 15 years in line with the German government's climate and energy policy objectives. A further three scenarios have to consider the development of methane and hydrogen demand for the year 2045 with a range of probable developments based on the German government's statutory and other climate and energy policy targets. Following consultation with the electricity transmission system operators and the BNetzA, the modelling years 2037 and 2045 were chosen for the Gas and Hydrogen Network Development Plan 2025. It should be noted that demand is modelled for 2037 (2045), for example, and that the necessary infrastructure must already be in place by the end of the previous year, 2036 (2044). This fact was taken into account by the gas TSOs and operators of hydrogen transmission in setting the commissioning dates.

In addition, the BNetzA approved the security of supply scenario for methane proposed by the gas TSOs for the modelling year 2030 in order to be able to take the results of a shorter-term demand analysis into account in the network development planning.

The draft Network Development Plan, drawn up on the basis of the Scenario Framework, must be published by KO.NEP on its website before being submitted to the regulatory authority so that the public and all existing and potential network users, as well as affected network operators, have the opportunity to comment. The draft made available for consultation and subsequently revised must then be submitted to the regulatory authority for approval. The BNetzA will review the revised draft for compliance with statutory requirements.

The authority may issue a change request, asking the gas TSOs and hydrogen transmission system operators to amend the submitted Network Development Plan. KO.NEP then needs to submit the amended Gas and Hydrogen Network Development Plan to the regulatory authority without delay and, upon request, provide all the information and data required by the authority for its review.

The regulatory authority will consult on the revised draft and subsequently approve the draft Gas and Hydrogen Network Development Plan submitted by the gas TSOs and hydrogen transmission system operators, taking into account public participation in the process.

1.1.2 European Network Development Plan

At European level, the gas transmission system operators are organised in the European Network of Transmission System Operators for Gas (ENTSO-G). ENTSO-G also draws up a Network Development Plan for the European transmission network every two years, the Ten-Year Network Development Plan (TYNDP). The TYNDP 2024 for the European methane and hydrogen network was published in October 2025. In accordance with Articles 60 and 61 of Regulation (EU) 2024/1789 of the European Parliament and of the Council, a Union-wide Network Development Plan for hydrogen must be drawn up every two years. During a transitional period until 1 January 2027, ENTSO-G is working with the European Network of Network Operators for Hydrogen (ENNOH), which represents hydrogen transmission network operators, to develop the Union-wide Network Development Plan for hydrogen. The Union-wide Network Development Plan 2028 for hydrogen is being developed by ENNOH [EU 2024].

Based in part on the TYNDP, the second "Union list of projects of common interest and projects of mutual interest" (Union list) was published on 1 December 2025. It lists the Projects of Common Interest (PCI) and the Projects of Mutual Interest (PMI), including projects from Germany [EC 2025].

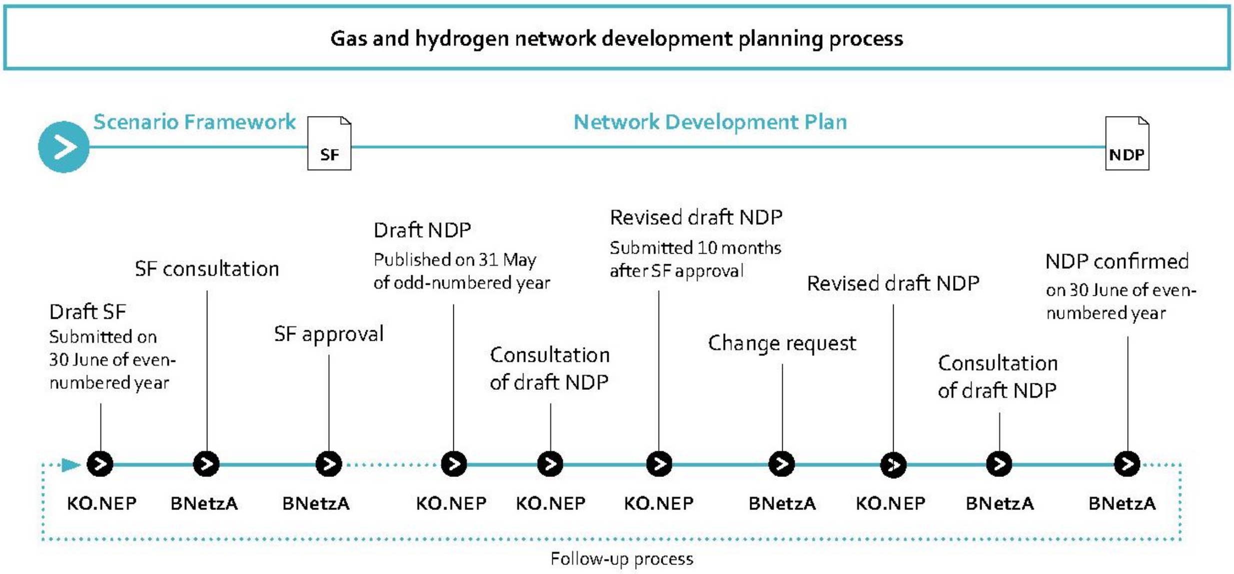
1.2 Timeline and structure of the Gas and Hydrogen Network Development Plan 2025

The gas TSOs and hydrogen transmission system operators are required under Section 15a EnWG to submit their Network Development Plan every two years. This is in line with the publication requirements for electricity transmission system operators.

The draft of the Gas and Hydrogen Network Development Plan 2025 is published in two stages, as provided for in Sections 15c and 15d EnWG. Based on the Scenario Framework approved by the BNetzA on 30 April 2025 (Ref. 4.13.01/11#1), the transmission system operators first published their draft Gas and Hydrogen Network Development Plan 2025 on 3 March 2026. The draft was then put out to public consultation until 27 March 2026.

Based on the comments received and the outcome of the consultation, the Gas and Hydrogen Network Development Plan was subsequently revised and submitted to the BNetzA on 1 June 2026.

Figure 1: Methane and hydrogen network development planning process



Source: Coordination Office for Gas and Hydrogen Network Development Planning

The current NDP cycle is characterised by a multitude of new legal requirements for gas TSOs and hydrogen transmission system operators. With the Scenario Framework confirmed in April 2025, the BNetzA has broadened the scope of consideration compared to the previous cycle to reflect changes in the energy industry and technological conditions.

A key element here is the integrated view of the two energy sources methane and hydrogen. This requires an iterative coordination process in order to be able to develop the hydrogen infrastructure largely from the existing methane infrastructure. Owing to this integrated view and the requirements defined for the Scenario Framework, the number of scenarios and modelling variants has increased significantly.

Given the process-related interdependencies between methane and hydrogen, the draft Gas and Hydrogen Network Development Plan 2025 contained the modelling results for methane for the years 2030, 2037 and 2045, as well as the results for hydrogen in 2037. The revised draft now also includes the hydrogen modelling results for 2045 as well as a detailed analysis of exit capacities at cross-border interconnection points (cross-border IPs) for 2037 that do not require expansion. In addition, the revised draft also includes the results of the modelling of market-based instruments (MBIs) for methane.

1.3 Databases used for the Gas and Hydrogen Network Development Plan 2025

The Gas NDP database published by KO.NEP at www.nep-gas-datenbank.de contains the input variables for the modelling done for the Network Development Plan. These variables are checked for their feasibility in various load cases and confirmed, possibly for defined expansion measures. One such load case is peak load, which corresponds to maximum network utilisation. Given its importance for methane modelling, it is described in more detail in chapters 3, 5 and 6.

The Gas NDP database also contains master data, capacities, expansion measures and information on market area conversions from L-gas to H-gas. The modelling results for the methane network in 2045 can be found in chapter 6.3.2 , and the hydrogen measures for 2045 are set out in chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**.

Unlike its 2022–2032 predecessor, the new Gas Network Development Plan shows the information for the methane and hydrogen infrastructure in the Gas NDP database using different tiles for methane and hydrogen for the first time.

Figure 2: Landing page of the Gas NDP database with excerpt from the methane and hydrogen tiles

Source: Coordination Office for Gas and Hydrogen Network Development Planning

The following chapters of the Network Development Plan refer to the database cycle "2025 – NDP 2nd draft" available in the Gas NDP database. All available data can be downloaded.

For this revised draft of the Gas and Hydrogen Network Development Plan 2025, the gas TSOs and hydrogen transmission system operators have also populated the new legally required topology database with the network models, consisting of the network topology and the modelled load cases used for the Gas and Hydrogen Network Development Plan 2025.

Any questions about the Gas NDP database can be directed to KO.NEP.

1.4 Consideration of the results of the public consultation

In accordance with Section 15c(4) EnWG, KO.NEP invited the public, including actual and potential network users, to comment on the draft Gas and Hydrogen Network Development Plan 2025 during the period from 3 March 2026 to 27 March 2026.

A total of 44 submissions were received during this period. An overview of the topics raised in these submissions can be found in **Fehler! Verweisquelle konnte nicht gefunden werden.** ("Evaluation of comments").

Following the consultation and the review of the comments received, the gas TSOs and hydrogen transmission network operators revised the Gas and Hydrogen Network Development Plan 2025 both substantively and editorially. These revisions affect both the Gas and Hydrogen Network Development Plan 2025 itself and the Gas NDP database.

Apart from adding this chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**, the following amendments and/or additions were made to the draft of the Gas and Hydrogen Network Development Plan 2025:

- **Chapter 3.4 :** Additional explanations on entry and exit capacities as well as load cases for hydrogen
- **Chapter 6.1.2 :** Additional explanations on hydrogen entry capacities
- **Chapter 6.2.2 (and in the Gas NDP database):** Identification of specific M&R stations in the hydrogen infrastructure for the year 2037
- **Chapter** Fehler! Verweisquelle konnte nicht gefunden werden.**:** Addition of an analysis of hydrogen exit capacities at cross-border IPs for 2037 that do not require network expansion
- **Chapter** Fehler! Verweisquelle konnte nicht gefunden werden.**:** Addition of input variables and results for the 2045 hydrogen modelling
- **Chapter 6.5 :** Addition of the NewCap modelling results (MBI)
- **Chapter 7.5 :** Additions / changes to the network expansion proposal
- **Gas NDP database, Annexes and Appendices:** Updated tables and files, together with partial revisions to the commissioning dates for hydrogen projects in light of the latest findings and political developments

In addition, the Gas NDP database has been updated to include the current "2025 – NDP 2nd Draft" cycle.

This chapter 1.4 focusses on the main aspects of the comments received as part of the consultation process:

Approved Scenario Framework (chapter 2)

The comments on chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**(approved Scenario Framework) addressed both fundamental questions regarding the design of the scenarios and their implications for security of supply and network development planning. Several comments focussed on the 2030 security of supply scenario (scenario 4). The vast majority of comments welcomed the introduction of this scenario and emphasised its importance for ensuring security of supply in the short term during the transition phase. In particular, respondents noted that the scenario accurately reflects the actual demand reported by power plants, industry and distribution system operators. Several comments also suggested that the security of supply scenario should be retained or further developed in future.

Many comments highlighted the role of hydrogen as a key energy carrier in the transformation process. There was broad consensus on the importance of hydrogen, particularly for industry and the power generation sector. However, its use in other sectors prompted a more nuanced debate. While some respondents supported scenario 1 with its early and widespread deployment of hydrogen, others questioned the assumed use of hydrogen in private households and, in particular, for space heating, arguing that this would be economically challenging.

One of the main and most contentious issues raised in the comments concerns scenario 3, which assumes a comparatively slow hydrogen ramp-up and a prolonged role for methane, in some cases involving the use of CCS/CCU. A large number of respondents viewed this scenario somewhat critically, considering it implausible from both an energy and climate policy perspective. In particular, doubts were expressed as to whether the assumed developments in the CCS-based power generation sector are realistic. Several respondents suggested that scenario 3 should be treated primarily as a sensitivity, with the more transformation-oriented scenarios serving as the main basis for long-term network planning. At the same time, some comments highlighted the role of scenario 3 as a safeguard against market risks and as a way of helping to avoid misdirected investment.

The comments also addressed the role of biomethane. A number of market participants argued that biomethane is not yet sufficiently reflected in the Scenario Framework or in network development planning more broadly, and called for greater quantitative and geographical integration, particularly in light of the growing European biomethane markets and increasing cross-border trade flows.

The gas TSOs and hydrogen transmission system operators will take these comments into account in preparing the draft Scenario Framework 2027.

Framework conditions and input variable for modelling: Role of storage (chapters 3 and 6)

Only a limited number of comments were received regarding the treatment of storage sites in the development plan. These comments highlight, on the one hand, the need for forward-looking planning of hydrogen storage requirements and for adequate consideration of hydrogen withdrawal capacities during "dark doldrums", i.e. periods of low wind and solar capacity. In addition, the importance of methane storage potential is emphasised.

The gas TSOs and hydrogen transmission system operators also stress the fundamental importance of storage for the gas sector, particularly during prolonged dark doldrums. Scenario 4 (2030) in particular makes extensive use of the existing storage infrastructure in order to safeguard security of supply.

In addition, KO.NEP has established a dedicated Storage Working Group to provide a further platform for exchange between network and storage operators. This enables regular dialogue on the use of storage infrastructure to ensure the efficient supply of methane and hydrogen and on its possible integration into the network development planning process.

Framework conditions and input variables for modelling: Power plants connected to distribution networks (chapter 3)

Several comments addressed the inclusion of power plants connected to distribution networks in the modelling. In particular, respondents pointed to methodological differences in the treatment of power plants connected to distribution networks as compared with those connected directly to the transmission network.

Gas transmission system operators are required to carry out scenario-based modelling in accordance with the provisions of the EnWG and the associated Scenario Framework. On this basis, however, it is not always possible to forecast precise developments for individual interconnection points. Nevertheless, demand developments at interconnection points associated with significant power plant demand in distribution networks were adjusted individually wherever possible. This required assumptions to be made regarding efficiency levels. The request for information on the LFP 2.0 and on distribution network development plans for the next NDP cycle will further improve the modelling basis in future.

Sufficient level of freely allocable capacity (chapter 3)

Some comments addressed the required capacity levels and the methodology for determining a sufficient level of freely allocable capacity (FAC).

With regard to exports, respondents noted that transit volumes could remain higher than assumed in the current Network Development Plan beyond 2037 and argued that the projected export volumes were incompatible with the continuing demand expected from neighbouring countries.

The transmission system operators would first point out that the plans up to and including 2035 envisage maintaining the export capacities set out in the Scenario Framework. The reduction in export capacities envisaged for 2037 and 2045 is consistent overall with the requirements laid down in the BNetzA's approval of the Scenario Framework. Any differing requirements identified by neighbouring countries, particularly those arising from existing network development plans, may be taken into account for the next Scenario Framework.

Some respondents also criticised the fact that, for southern German and downstream network interconnection points, detailed figures for specific points of the system are only provided up to 2033, arguing that this provides only limited certainty for distribution system operators and for the supply of gas-fired power plants.

The transmission system operators point out that no changes have been made to the existing approach for distribution system operators or for downstream interconnection points serving end users. As in previous network development plans, developments at network interconnection points continue to be based on customers' demand forecasts. Developments are not only shown over a 10-year period as in previous plans ("2025-SR" cycle in the Gas NDP database), but are also published for the year 2037 ("2025-NDP 2nd Draft" cycle in the Gas NDP database).

The methodology used to determine entry capacity, which is based on statistical quantiles of historical bookings, was generally regarded as understandable. However, it was noted that market behaviour between 2022 and 2024 had been shaped by low consumption resulting from the Ukraine crisis and mild winters. Respondents therefore stressed the importance of maintaining flexibility and resilience in gas supply, particularly in the event of short-term disruptions caused by unforeseen events.

The gas transmission system operators would first clarify that entry capacities are not reduced to the 96.2% quantile of historical bookings, neither overall nor for individual import corridors. Owing to the additional consideration given to security of supply and diversification aspects, as described in chapter 3.3.3 , the actual level of supply is significantly higher. By way of illustration, FAC supply on the Norwegian import corridor in the 2026/2027 gas year amounts to 51.2 GWh/h, more than one third above the 96.2% booking quantile. From the transmission system operators' perspective, the commissioning of new LNG terminals increases flexibility and competition on the entry side, although it does not necessarily result in higher overall entry volumes. This competitive environment must therefore be reflected in the projected development of entry FACs over time. As part of future updates to the sufficient level assessment, the allocation of FACs across entry points will continue to be adjusted in line with observed usage patterns.

Likewise, future changes in consumption and export levels will be taken into account in determining overall supply requirements. Figures 8 and 9 demonstrate that sufficient entry FACs remain available even during colder winters. In addition, fixed entry capacities at cross-border IPs are available as conditionally firm, freely allocable capacity (cFAC) during periods of low temperatures.

It is also worth noting that unused entry capacities at one point in the network allow increased capacities at competing points to be utilised without the risk of interruption. Such a mechanism would be particularly effective in the event of short-term outages of import infrastructure.

The transmission system operators believe that the methodology applied ensures that FACs are made available to the market to the extent required, while remaining sufficiently flexible to respond to changes in market behaviour.

Status of network expansion measures (chapter 4)

Several comments addressed the implementation status of the network expansion measures, with particular requests for information on delays affecting individual projects.

The gas TSOs and hydrogen transmission system operators point out that details on the current implementation status of the relevant NDP measures, in accordance with Section 15c(2) EnWG, are set out in Appendix 2 to the document, including the reasons for changes to planned commissioning dates, and that current project phases have also been made available in the Gas NDP database. As part of rolling network development planning, the implementation statuses of network expansion measures are constantly updated.

Scenario 4: Security of supply assessment for methane 2030 (chapter 5)

Several comments welcome the demand-based approach in scenario 4, regarding it as an important addition to the long-term transformation scenarios based on the years 2037 and 2045.

Respondents particularly emphasised that the assumptions underpinning this scenario are based on validated data relating to power plants, industry and distribution networks, and therefore provide a more accurate reflection of actual demand.

Both explicitly and implicitly, the comments indicate a desire for a demand-based security of supply scenario to be permanently incorporated into future network development plans. In addition, several respondents suggested that the results of the security of supply scenario should be given greater weight in the derivation of the network expansion proposal.

The transmission system operators welcome the positive feedback on the security of supply scenario (scenario 4) and see it as confirmation of their intention to continue assessing the added value of a demand-based approach in future network development plans. They also note that scenario 4, alongside scenarios 1–3, is already taken into account for the network expansion proposal (see chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**). The criteria CH_4 (1)–(3) relate directly to the expansion of the methane network and are not linked to measures for converting pipelines to hydrogen, whereas criteria CH_4 (4)–(5) relate to measures aimed at reinforcing the natural gas network for the hydrogen transition. In addition, network expansion proposals derived from scenarios 1–3 will continue to be reviewed in future network development plans with regard to both feasibility and necessity. Thus, scenario 4 is appropriately taken into account for the preparation of the network expansion proposal.

Interaction of different entry capacities (chapters 5 and 6)

Respondents considered the projected LNG entry capacities to be overly optimistic and, in light of external factors such as geopolitical uncertainty, of limited reliability. It was pointed out that security of supply during cold winter periods is ensured primarily by storage facilities, whose withdrawal capacities at times exceed import volumes at cross-border IPs and LNG terminals. Against this background, respondents recommended that existing storage capacities should be taken into account at least to the extent of import capacity, as storage infrastructure is viewed as more robust and not yet sufficiently reflected in the models. In particular, given that some projected LNG capacities have not yet been fully realised, respondents argued that storage capacity projections should be given greater weight.

The transmission system operators point out that the assumptions regarding LNG entry capacities are based on the requirements laid down in the Scenario Framework approved by the BNetzA. For scenario 4, the BNetzA has specified a minimum LNG entry capacity of 79 GWh/h, which had to be incorporated into the model as a binding requirement. The underlying assumptions are reassessed as part of every NDP process, allowing the framework conditions to be updated where necessary in line with actual market developments.

Clusters for the hydrogen ramp-up (chapter 6)

Several comments addressed hydrogen exchange capacities between the hydrogen ramp-up clusters. The Gas and Hydrogen Network Development Plan 2025 models the years 2037 and 2045 for hydrogen, as required by law. Cluster exchange capacities are not themselves part of the Network Development Plan, but are considered separately by the hydrogen transmission network operators in accordance with the provisions of operative part 9 of the WaKandA decision.

Consideration of hydrogen projects (chapter 6)

Several comments referred to additional hydrogen projects, particularly in northern Germany, which are not currently included in the Network Development Plan.

The inclusion of projects follows the procedure confirmed by the BNetzA in its approval of the Scenario Framework. In this context, the requirements identified through the joint market survey are assessed alongside the respective project status.

Hydrogen scenarios in the NDP vs. actual hydrogen ramp-up (chapter 6)

Several comments highlighted discrepancies between the scenarios used and the actual pace of the hydrogen ramp-up.

Through scenarios based on the orientation scenarios set out in the system development strategy, the Gas and Hydrogen Network Development Plan 2025 aims to present a broad spectrum of possible energy pathways in order to reflect a wide range of potential future developments.

Power plants in the 2045 methane modelling (chapter 6)

Several respondents noted that it should be verified whether the power plant sites included in the 2045 methane modelling are physically connected to the transmission network, in order to enable accurate network modelling.

The transmission system operators point out that power plant sites were incorporated into the modelling in accordance with the specifications laid down by the BNetzA. The objective of the 2045 methane modelling is to identify a methane network capable of accommodating the necessary transit flows while also supplying the relevant power plant sites. To this end, the modelling ensures that peak demand can be met via cross-border interconnection points and storage facilities, and that the required capacities are available in the vicinity of the respective power plant sites.

Biomethane in the 2045 methane modelling (chapter 6)

Several comments also criticised the fact that, despite the recognised importance of biomethane, the Network Development Plan addresses its future role in the 2045 modelling only in broad methodological terms, without identifying specific entry capacities or regions.

The transmission system operators share the view that biomethane is an important component of a sustainable energy supply and will continue to play a significant role in the future energy system. They also acknowledge that the system development strategy did not identify sufficient biomethane capacities. However, from the transmission system operators' perspective, considerable uncertainty remains regarding the development of entry capacities and potential entry locations. They therefore intend to include more detailed information in future network development plans once more concrete results from transformation planning become available.

Network expansion proposal (chapter 7)

Several comments welcomed the hydrogen and methane network expansion proposal submitted by the gas TSOs and hydrogen transmission system operators as a robust and transparent planning framework. Some consultation participants nevertheless called for a stronger focus on particular scenarios or for the exclusion of individual scenarios altogether.

The gas TSOs and hydrogen transmission system operators believe that the chosen multi-scenario, criteria-based approach to deriving the network expansion proposal successfully balances scenario-based and demand-based planning approaches (see chapter 7).

Network expansion proposal for methane (chapter 7)

With regard to the methane network expansion proposal, several respondents argued that the security of supply perspective for methane (scenario 4) should have been given greater weight in the derived expansion proposal.

The transmission system operators believe, however, that the results of the MBI modelling published in the revised draft of the Gas and Hydrogen Network Development Plan 2025 (see chapter 6.5) show that scenario 4 has already been sufficiently taken into account.

Changes to core network measures (chapter 7)

The timing of hydrogen infrastructure measures was also the subject of several comments, revealing differing views. On the one hand, adjustments to commissioning dates were recognised as necessary for demand-driven network expansion and against the backdrop of approval procedures and capacity constraints among service providers. On the other hand, respondents argued that postponing individual core network sections creates uncertainty and directly jeopardises investment planning for downstream projects.

The hydrogen transmission network operators have set out the reasons for adjusting commissioning dates transparently in **Fehler! Verweisquelle konnte nicht gefunden werden.**, describing them individually for each measure. These reasons vary considerably, and each case must ultimately be assessed on its own merits. The possibility of adjusting commissioning dates for core network measures up to 2037 is also expressly provided for in the EnWG and is subject to continuous review as part of network development planning. The transmission system operators believe that the completion of all proposed core network expansion measures by 31 December 2037 remains realistic.

Ellund-Niebüll pipeline (chapter 7)

Several comments criticised the omission of the Ellund-Niebüll core network pipeline as technically unjustified, while also pointing to the significant risks this poses to the further development of the hydrogen economy in northern Schleswig-Holstein. Respondents consistently stressed that the pipeline represents a key element of hydrogen infrastructure for projects in the district of North Friesland, some of which are already at an advanced stage of development. Several comments further argued that the hydrogen entry capacity of only 75 MW_{th} at the Bosbüll site, as included in the Gas and Hydrogen Network Development Plan 2025, significantly understates the actual and foreseeable transmission requirements up to 2030. In the view of respondents, the assumptions underpinning the modelling reflect only the project status recorded in the market survey conducted in the first quarter of 2024 and fail to capture the considerably more advanced state of project development since then. Particular emphasis was placed on the regional development potential associated with this hydrogen pipeline, including the long-term connection of electrolysis capacities totalling up to 1.1 GW_e, as well as on the strategic importance of the Ellund cross-border interconnection point as a European network hub.

At the same time, the draft Gas and Hydrogen Network Development Plan 2025 must be viewed in the context of the amended legal framework established under the EnWG. For the first time, methane and hydrogen infrastructure are being planned jointly on the basis of the Scenario Framework approved by the BNetzA. Within this framework, core hydrogen network measures with planned commissioning dates after 31 December 2027 are subject to a renewed assessment of their necessity pursuant to Section 28q(8) EnWG. The omission of the Ellund-Niebüll pipeline from the draft resulted from this legally required assessment and was based on the results of the scenario-based hydrogen modelling for 2037.

The comments nevertheless make clear that many of the arguments advanced – including investment certainty, regional value creation, and broader energy and industrial policy considerations – relate primarily to the long-term strategic significance of the Ellund-Niebüll pipeline. These arguments therefore primarily concern the fundamental necessity of the measure rather than the current status of its planning classification as part of the scenario-based analysis underpinning the Gas and Hydrogen Network Development Plan 2025. Several respondents also noted that the project landscape has evolved significantly since the market consultation, meaning that current connection requests and updated planning statuses could only be reflected to a limited extent in the modelling.

A large number of respondents therefore supported reintegrating the Ellund-Niebüll pipeline into the revised draft of the Gas and Hydrogen Network Development Plan 2025. From the perspective of coherent NDP project development, a revised timetable for the measure appears particularly appropriate, taking into account both the remaining uncertainties surrounding market ramp-up and the increasingly concrete nature of project prospects. According to the comments, such an approach would preserve the pipeline as a strategic expansion option within the hydrogen network while remaining consistent with both the methodological principles of scenario analysis and the statutory obligation to review core network measures. At the same time, it would send an important signal regarding planning certainty and investment readiness in a strategically important region of the energy transition in northern Germany.

For the reasons outlined above, the hydrogen transmission network operators propose including the Ellund-Niebüll core network measure in the hydrogen network development proposal. The hydrogen transmission network operators have added a section on this measure in Chapter 7.5 .

Gas and hydrogen network development planning process

Several comments welcomed and broadly supported the first integrated network development planning process for gas and hydrogen. At the same time, some respondents argued that the process requires specific adjustments to reflect the high level of market dynamism, particularly in relation to hydrogen. Among other things, comments noted that the current Network Development Plan does not fully capture the latest project data or the most recent capacity reservations.

The network development planning process is a rolling process established under the Energy Industry Act and carried out every two years in order to respond to market developments. Overall, it is a complex and iterative process involving multiple consultation and participation phases.

Given the structure and complexity of network development planning, there have to be cut-off dates for input parameters for modelling. The Scenario Framework is approved by the BNetzA, and the modelling for the network development plan must be carried out on that basis. As a result, there will always be recent developments that cannot be reflected in a given Network Development Plan because they emerge after the relevant deadlines. However, as noted above, the planning process is repeated every two years in order to incorporate the latest available information at that time.

Approved Scenario Framework 2

2 Approved Scenario Framework

On 30 April 2025, the BNetzA approved the Scenario Framework for the Gas and Hydrogen Network Development Plan 2025–2037/2045 on the basis of Section 15b EnWG. The draft by the gas transmission system operators had been submitted to the BNetzA by KO.NEP on 1 July 2024, within the deadline, and then made available for public consultation by the BNetzA in the version dated 16 August 2024.

The approved Scenario Framework contains four different scenarios, which form the binding basis for network development planning in the methane and hydrogen sector. The scenarios represent possible development paths for Germany's future energy supply with the goal of greenhouse gas neutrality by 2045, thus reflecting the range of possible decarbonisation paths. The scenarios differ mainly in terms of hydrogen use and electrification in the individual sectors, the pace of transformation and the role of methane supply.

The approved scenarios are designed to reflect the remaining uncertainties regarding future energy policy as well as technological and market developments, thus facilitating the development of a methane and hydrogen infrastructure that is resilient to various developments.

The scenarios range from a rapid and, in some cases, cross-sector hydrogen ramp-up to a rather conservative scenario with continued high methane use and a delayed hydrogen ramp-up until 2037, followed by an accelerated development of the hydrogen economy between 2037 and 2045. Scenarios 1, 2 and 3 each cover the years 2037 and 2045, while the fourth scenario only considers the year 2030 and focuses on short-term security of supply in the methane sector. The BNetzA has specified the following capacities for methane and hydrogen for each scenario, broken down by sector.

Table 2: Methane exit capacity according to the approved Scenario Framework

Sector	Scenario 1 2037	Scenario 2 2037	Scenario 3 2037	Scenario 1 2045	Scenario 2 2045	Scenario 3 2045	Scenario 4 2030
Power plants	17 GW_e	21 GW_e	58 GW_e	0 GW_e	0 GW_e	22 GW_e	41 GW_e*
Industry	25 GWh/h	20 GWh/h	31 GWh/h	0 GWh/h	0 GWh/h	0 GWh/h	40 GWh/h**
Private households Commerce/trade/services Transport District heating	71 GWh/h	66 GWh/h	122 GWh/h	0 GWh/h	0 GWh/h	0 GWh/h	240 GWh/h***
Cross-border IPs	53 GWh/h	49 GWh/h	49 GWh/h	*****	*****	*****	69 GWh/h
Storage	****	*****	*****	--	--	****	****

* excluding power plants in the distribution system

** excluding industry in the distribution system

*** including power plants and industry in the distribution system

**** The exit/entry capacity ratio must be appropriate to allow storage facilities to be filled completely.

***** transits

Source: BNetzA 2025, Scenario Framework approval, p. 6

Table 3: Methane entry capacity according to the approved Scenario Framework

<table>
<tr><th>Sector</th><th>Scenario 1 2037</th><th>Scenario 2 2037</th><th>Scenario 3 2037</th><th>Scenario 1 2045</th><th>Scenario 2 2045</th><th>Scenario 3 2045</th><th>Scenario 4 2030</th></tr>
<tr><td>Cross-border IPs</td><td>at least 18 GWh/h</td><td>at least 16 GWh/h</td><td>at least 16 GWh/h</td><td>--</td><td>--</td><td rowspan="2">Determination of sufficient entry capacity with due consideration for power plant capacity and the respective allocation points</td><td>152 GWh/h</td></tr>
<tr><td>Storage</td><td>at least 42 GWh/h</td><td>at least 37 GWh/h</td><td>at least 37 GWh/h</td><td>--</td><td>--</td><td>at least 130 GWh/h</td></tr>
<tr><td>LNG</td><td>at least 16 GWh/h</td><td>at least 14 GWh/h</td><td>at least 79 GWh/h</td><td>--</td><td>--</td><td>--</td><td>at least 79 GWh/h</td></tr>
<tr><td>Domestic production</td><td>1 GWh/h</td><td>1 GWh/h</td><td>1 GWh/h</td><td>--</td><td>--</td><td>--</td><td>3 GWh/h</td></tr>
<tr><td>Biomethane/green gases</td><td>*</td><td>*</td><td>*</td><td>*</td><td>*</td><td>*</td><td>*</td></tr>
<tr><td colspan="8">The sum of the methane entry capacities must in any case cover at least the sum of the methane exit capacities.</td></tr>
</table>

* Any assessment of the development of biomethane feed-in should follow the procedure described in the draft Scenario Framework based on the BNetzA's/BKartA's current 2024 monitoring report.

Source: BNetzA 2025, Scenario Framework approval, p. 6

Table 4: Hydrogen exit capacity according to the approved Scenario Framework

Sector	Scenario 1 2037	Scenario 2 2037	Scenario 3 2037	Scenario 1 2045	Scenario 2 2045	Scenario 3 2045
Power plants	29 GW_e	41 GW_e	5 GW_e	60 GW_e	81 GW_e	59 GW_e
Industry	35 GWh/h	18 GWh/h	7 GWh/h	92 GWh/h	42 GWh/h	42 GWh/h
Private households	11 GWh/h	0 GWh/h	0 GWh/h	21 GWh/h	0 GWh/h	0 GWh/h
Commercial/trade/services	3 GWh/h	0 GWh/h	0 GWh/h	5 GWh/h	0 GWh/h	0 GWh/h
Transport	4 GWh/h	0 GWh/h	0 GWh/h	7 GWh/h	0 GWh/h	0 GWh/h
Cross-border IPs	*	*	*	30 GWh/h	30 GWh/h	30 GWh/h
Storage	**	**	**	**	**	**

* Capacitiy achievable without expansion still to be determined.

** The exit/entry capacity ratio must be appropriate to allow storage facilities to be filled completely.

Source: BNetzA 2025, Scenario Framework approval, p. 5

Table 5: Hydrogen entry capacity according to the approved Scenario Framework

Sector	Scenario 1 2037	Scenario 2 2037	Scenario 3 2037	Scenario 1 2045	Scenario 2 2045	Scenario 3 2045
Cross-border IPs	at least 58 GWh/h	at least 58 GWh/h	at least 10 GWh/h	at least 58 GWh/h	at least 58 GWh/h	at least 58 GWh/h
Storage	at least 36 GWh/h	at least 36 GWh/h	at least 6 GWh/h	at least 36 GWh/h	at least 36 GWh/h	36 GWh/h
Other imports (including LH_2 and derivatives)	at least 4 GWh/h	at least 4 GWh/h	at least 1 GWh/h	at least 4 GWh/h	at least 4 GWh/h	at least 4 GWh/h
Electrolysis	at least 32 GW_e	42 GW_e	at least 6 GW_e	at least 32 GW_e	58 GW_e	at least 32 GW_e
The sum of the entry capacities for hydrogen must cover at least the sum of the exit capacities for hydrogen in each load case.						

Source: BNetzA 2025, Scenario Framework approval, p. 5

Scenario 1

This scenario assumes a rapid and far-reaching ramp-up of the hydrogen economy. Hydrogen is used in all sectors, i.e. not only in large-scale power generation, but also in industry, transport, commerce, trade and services (CTS), and private households (PHH). It is the only scenario that forecasts significant hydrogen demand in all consumption sectors as early as 2037.

The early replacement of large parts of today's methane demand with hydrogen requires high hydrogen entry capacities for various sources, including electrolysers, storage facilities, imports and cross-border IPs.

In this scenario, the ramp-up in hydrogen is accompanied by a rapid decline in methane consumption, particularly in industry, PHH and power plants as early as 2037, with fossil methane consumption in Germany ending by 2045.

Scenario 2

This scenario focuses on the widespread electrification of energy supply. Hydrogen is mainly used in the power plant sector, primarily as a flexible energy source to back up highly intermittent wind and solar sources. Hydrogen is also used in industry.

Other sectors do not use hydrogen. The assumptions are closely aligned with scenario B of the approved Scenario Framework for the Network Development Plan for Electricity, particularly with regard to the locations of power plants and electrolysers, based on a common data set.

Methane use also declines sharply in this scenario. While exit capacities are still planned for all sectors in 2037, methane consumption will be completely phased out by 2045, as in scenario 1.

Scenario 3

Compared to the first two scenarios, this scenario sets out a more cautious transformation path in which methane continues to play an important role for a longer period of time. The switch to hydrogen is delayed and on a smaller scale.

In scenario 3, hydrogen use by industry and power plants is still low in 2037. Although it increases by 2045, it remains well below the consumption levels of the other two scenarios. Use is limited to industry and power plants, while the PHH, transport and CTS sectors do not use hydrogen. Methane continues to be used to some extent in the power plant sector after 2045, with CO_2 emissions being mitigated by technologies such as carbon capture and storage (CCS) or carbon capture and utilisation (CCU).

Scenario 4

The fourth scenario adds a short-term perspective to the long-term paths of scenarios 1 to 3 in that it considers only the year 2030 and serves to secure the supply of methane during the hydrogen ramp-up.

This so-called security of supply scenario was included at the suggestion of the gas TSOs in order to further analyse developments up to 2030.

In contrast to the German government's more normative long-term scenarios (LTSs), which describe a range of possible developments aimed at greenhouse gas neutrality by 2045, this scenario is based on specific methane demands reported to the TSOs, e.g. as part of long-term forecasts (LTFs) by distribution system operators (DSOs), capacity requests from power plants in accordance with Sections 38 and 39 of the Gas Network Access Ordinance (GasNZV), and on the basis of further capacity demands from industrial customers directly connected to the gas transmission system and existing gas-fired power plants. This means that this scenario can serve as a reliable basis for determining short-term demand trends.

The four approved scenarios highlight the need for integrated methane and hydrogen infrastructure planning for the first time and illustrate the dynamic interactions between the two systems: while hydrogen demand increases at different rates depending on sector and time frame, methane consumption declines accordingly at different rates. Tables 1 to 4 of the approved Scenario Framework provide the quantitative reference data (overall figures) for integrated network development planning.

Figure 3 provides an overview for methane and hydrogen across the different scenarios by sector on the exit side. It shows the overall figures for industry, CTS, PHH, transport, district heating and power plants as well as the total for the years 2030, 2037 and 2045. For methane, the overall figures from scenario 4 for 2030 are shown to illustrate the situation.

The different scenarios clearly show the varying transformations in methane supply. Scenario 1 shows a development path with widespread use of hydrogen in all conceivable sectors, including PHH and transport. The hydrogen demand of the industrial sector doubles compared to 2030. In scenario 2, hydrogen is mainly used in the power plant sector and in industry. In scenarios 1 and 2, methane demand falls to 0 GWh/h in 2045. In scenario 3, the hydrogen ramp-up is delayed. In addition, methane will continue to be used in the power plant sector in 2045 with the use of CCS technology.

Figure 3: Overall figures from Scenario Framework approval

Source: Coordination Office for Gas and Hydrogen Network Development Planning

3 Framework and Input Variables for Modelling

3 Framework and Input Variables for Modelling

The following subchapters provide the relevant, overarching framework and the key input variables for the modelling process.

3.1 Regionalisation of capacity targets for methane and hydrogen

Regionalisation, i.e. the geographical breakdown of capacity demand for Germany as a whole by specific consumption locations, is a central part of scenario-based hydrogen and methane network planning.

It is only by identifying future centres of hydrogen demand that the core network approved by the BNetzA in October 2024 can be critically reviewed in terms of its appropriate design in line with the statutory mandate and be developed in a meaningful way for regions where increased hydrogen demand is identified.

Likewise, centres of demand should also be identified for methane, so that it is possible to specify the right expansion measures, for example, following the construction of a methane-fired power plant. Given the expected decline in methane demand, it will be necessary to make predictions as to how quickly demand will fall in which regions and which methane infrastructure will no longer be required. This is the only way to identify methane pipelines that can be repurposed for hydrogen transportation without compromising the security of gas supply so that the costs of the energy transition can be reduced.

The Network Development Plan 2025 is the first to apply two different approaches to determining demand and centres of consumption based on specified scenarios with defined energy requirements, each requiring its own methodology.

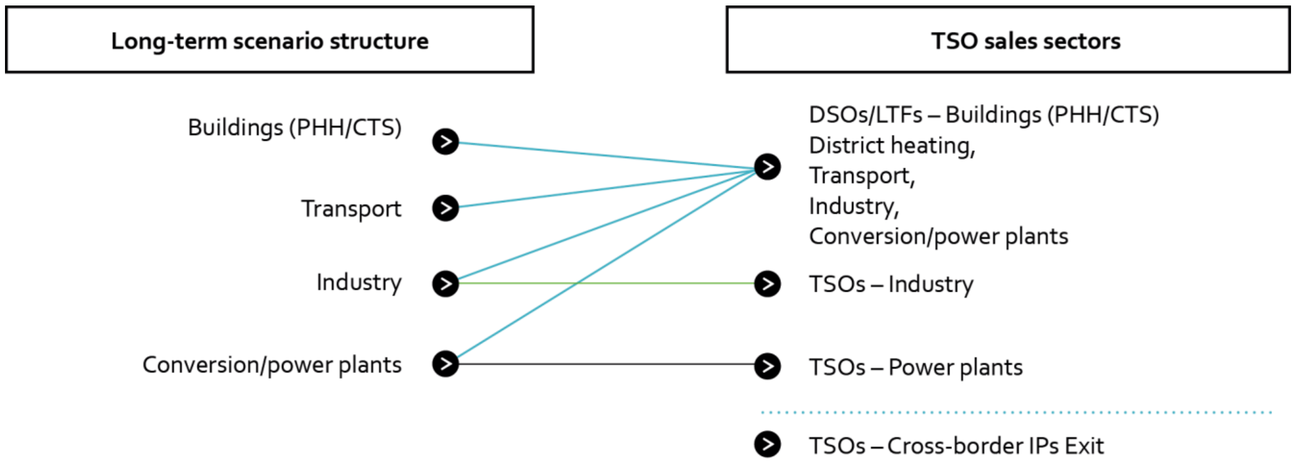
3.1.1 Demand-based approach

The demand-based approach, which forms the basis of the security of supply scenario for methane (scenario 4) for the year 2030, takes into account specific capacity requirements reported by market participants. The data basis includes the DSOs' long-term forecasts (LTFs) checked for plausibility, capacity requests by power plants in accordance with Sections 38 and 39 of the GasNZV, and the additional capacity demand of industrial customers directly connected to the gas transmission system and existing gas-fired power plants, with the total demand being calculated from the sum of many individual, geographically located reports. Demand is therefore already regionalised. The next step is essentially to systematically record and check these location-specific reports and assign them to the relevant entry and exit points in the network model. This creates a consistent overall picture that can be translated into a model.

3.1.2 Scenario-based regionalisation

In the scenario-based approach, which governs scenarios 1, 2 and 3 for methane and hydrogen in the target years 2037 and 2045, the overall figures in chapter 2 approved by the BNetzA provide the starting point. These figures, which are set out in the Scenario Framework, define the total capacity in each of the sectors in the target year. However, in their capacity balances, gas TSOs do not distinguish between sectors, but rather between industry and power plants directly connected to the gas transmission system and those sites that are connected to downstream distribution systems and therefore included in the DSOs' LTFs that cover the requirements of the industrial, power plant, private household, trade/commerce/services, district heating and transport sectors. For this reason, the first step is to transfer the sectoral targets of the approved scenarios to the sales structures of the gas transmission system operators, in accordance with Figure 4.

Figure 4: Allocation of the total methane capacity across Germany from the scenarios to the current capacity demand structure



Source: Coordination Office for Gas and Hydrogen Network Development Planning

The second step then is to regionalise these sectoral requirements, which are not assigned geographically. The capacity value specified in the overall figure for Germany as a whole is thus broken down into specific regional requirements.

In the case of methane, regionalisation across sectors follows the principle of a proportional reduction based on the reported requirements for 2030, both for consumers directly connected to the gas transmission system and for DSOs. In this context, a proportional reduction means that consumer demands in a customer group or sector are reduced by the same relative amount so that the capacity targets of the Scenario Framework are met. This approach is based on the assumption that DSOs in particular supply a large number of individual consumers who will not reduce their methane consumption fully at the same time but rather gradually. Industrial consumers also frequently use methane for different applications or in several technical facilities located at the same site. In such cases, consumption can often only be reduced gradually. The methane infrastructure will be needed for the duration of the transformation process, even if individual customers are already able to cover part of their energy demand with hydrogen in a given scenario. In some cases, it was assumed that some connection customers would no longer be supplied with methane in 2037.

The results of the first market survey on hydrogen projects conducted together with the electricity transmission system operators ("WEB survey") are a key input variable for the regionalisation process. This variable was also used for the BNetzA's list of power plant locations, among other things. The aim of the market survey on hydrogen projects (WEB survey) was to gather up-to-date information on projects currently executed as well as future plans for hydrogen production, storage and use, including Power-to-Gas (PtG) plants, along with the electricity consumption of large consumers from market participants and DSOs.

These elements and their specific role in the process of regionalising the scenarios for 2037 and 2045 are described in detail in chapters 3.3 and 3.4.

3.2 BNetzA list of power plant locations

A central element of the methane and hydrogen scenarios specified by the BNetzA is the list of power plant locations, which is part of the approved Scenario Framework. This list of locations is based, among other things, on capacity requests from power plants in accordance with Sections 38 and 39 of the GasNZV, the BNetzA's list of power plants (as of 21 November 2024) and the results of the 2024 market survey on hydrogen projects.

The list contains the electrical capacities (GW_e) to be applied in each of the scenarios for the power plants mentioned, separately for methane and hydrogen. Where project notifications in the market survey referred to existing power generating units (PGUs), these were linked to each other in order to prevent double counting of the same power generating unit in both methane and hydrogen. The individual power plants or individual PGUs were then allocated to the hydrogen scenarios for 2037 primarily on the basis of the commissioning dates specified in the market survey and the stated probability of project execution. Reported projects that were not included in the hydrogen scenario but could be assigned to an existing methane PGU were included by the BNetzA in the relevant methane scenario.

The BNetzA requires gas transmission system operators to use the electrical capacities of the power plant sites on the list as a basis for modelling the scenarios. Moreover, for 2045, the gap between the sum of the specified site capacities and the scenario's target values is to be filled with the addition of further hydrogen capacities at gird-supportive sites. The BNetzA has decided not to specify thermal gas connection ratings due to insufficiently valid and complete data and has instructed the gas transmission system operators to determine the corresponding connection capacities for existing power plants and new plants running on methane (possibly with CCU/CCS technology).

3.3 Input variables for methane

This chapter refers in particular to the input variables of scenarios 1 to 3 for the target years 2037 and 2045 in relation to methane. The input variables for the security of supply review for scenario 4 (2030) are presented in detail in chapter 5.2.

3.3.1 Exit capacity

The following subchapters provide an overview of the methane exit capacities for scenarios 1 to 3 for the target years 2037 and 2045. The gas transmission system operators do not make a specific distinction between natural gas, biomethane and other gases.

3.3.1.1 Power plants

The different methane scenarios are based on the electrical capacities specified in the BNetzA's list of power plant locations. Transferring the power plants to the gas transmission system operators' network structures meant first of all assigning the power generating units (PGUs) on the location list to specific network connection points in the gas transmission system or to a collective group of power plants supplied via downstream distribution systems. The thermal gas connection ratings were then derived as described in the scenarios below.

Regionalisation scenarios 1–3 (2037)

Scenario 1 (2037): This scenario takes account of all power plants on the location list that are not already designated for hydrogen use. The electrical capacity of these power plants is then proportionally reduced until the overall figure of 17 GW_e is reached (TSO power plants 10 GW_e, DSO power plants 7 GW_e).

Scenario 2 (2037): As in scenario 1, all relevant gas-fired power plants are taken into account. Their capacity is reduced proportionally to achieve the overall figure of 21 GW_e (TSO power plants 11 GW_e, DSO power plants 10 GW_e).

Scenario 3 (2037): Scenario 3 depicts a delayed transformation from methane to hydrogen in the power plant sector, among others. An electrical capacity of 58 GW_e is assumed here. This includes all existing power plants and newly planned plants that run on methane (possibly with CCU/CCS technology) (TSO power plants 42 GW_e, DSO power plants 16 GW_e).

Regionalisation scenarios 1–3 (2045)

Scenario 3 (2045): This scenario is based on an electrical capacity of 22 GW_e generated exclusively by newly built power plants with CCU/CCS technology connected to the gas transmission network.

The relevant gas connection capacities to be assumed in each case were determined by the gas transmission system operators as follows:

For power plant sites connected to and supplied by the gas transmission system (TSO network), a calculated efficiency for the entire power plant site was determined on the basis of the gas connection rating assumed for scenario 4 in 2030 and the electrical capacity for power generating units at this location, as shown in the power plant list. In individual cases, this efficiency was corrected if the transmission system operators had additional information on site-specific circumstances, such as a planned dual-fuel supply for the power plant. To determine the gas connection rating to be applied at the site in the relevant scenarios for 2037 and 2045, this efficiency was then offset against the electrical capacity specified in the scenario at the site according to the power plant list. Capacity requests pursuant to Sections 38 and 39 of the GasNZV were taken into account in accordance with the requested gas connection capacity.

For power plants supplied via the gas transmission network, the estimated thermal gas connection rating for the modelling years 2030 and 2037 is published in the Gas NDP database in the "2025 – NDP 2nd Draft " cycle in the "Capacities" tile. For the modelling year 2045, the gas connection ratings are shown in **Fehler! Verweisquelle konnte nicht gefunden werden.**.

For power plant sites connected to and supplied via a distribution system (DSO network), the technology used for electricity generation was determined for the individual PGUs on the basis of the market master data register, and an average efficiency was used here. Based on the individual efficiencies determined in this way, an average efficiency of 46% was calculated. To determine the total gas connection rating to be applied in the respective scenarios in 2037 for power plants supplied via the DSO network, this efficiency was finally offset against the electrical capacity to be applied in total in the relevant scenario for the DSO power plants.

Based on the procedure described above, the following gas connection ratings were determined, which were then used by the transmission system operators for the next steps:

Table 6: Electrical and thermal ratings of power plants

	Rating according to Scenario Framework approval	Sales structures of the gas transmission system operators		
	GW_e		GW_e	GW_{th}
Scenario 1 (2037)	17	TSO network	10	19
		DSO network	7	15
Scenario 2 (2037)	21	TSO network	11	23
		DSO network	10	21
Scenario 3 (2037)	58	TSO network	42	82
		DSO network	16	35
Scenario 3 (2045)	22	TSO network	22	44
		DSO network	0	0

Source: Coordination Office for Gas and Hydrogen Network Development Planning

The power plants, which will be included in the DSO network in the target year, are taken into account in the targets for DSOs (chapter 3.3.1.3). For power plants supplied via a distribution system, the estimated thermal gas connection rating is therefore not published individually in the Gas NDP database, but is part of the LTF of the DSO operating the relevant supply network.

Allocation points for new and system-relevant power plants

Since the 2013 Gas Network Development Plan, gas transmission system operators, in consultation with the BNetzA, have been using the efficient power plant product known as "firm, dynamically allocable capacity" (fDAC) for the supply of new, system-relevant power plants. The fDAC product, as defined by the BNetzA in its standardisation of capacity products in the gas sector (KASPAR) ref. BK7–18-052, ensures the supply of power plants with firm capacities, but not exclusively via the German virtual trading point (VTP), but also, in situations where this is necessary for technical reasons, via certain storage facilities, cross-border IPs or LNG entry points which ensure the supply of the power plant in a congestion situation.

Usually, the gas transmission system operators and the power plant operators contact each other in the course of determining the allocation points and coordinate their actions.

From the gas transmission system operators' perspective, the allocation points Ellund (Denmark), Bocholtz/Bunde/Elten/Zevenaar H (Netherlands), Eynatten (Belgium), Wallbach (Italy, France) and Oberkappel/Überackern/Überackern 2 (Austria) can be considered to be liquid, as confirmed by regular reports and analyses of gas market developments by the European regulatory authority ACER. For the allocation points Dornum and Emden (Norway is not considered by ACER), the gas transmission system operators consider liquidity to be guaranteed, given their role as key import points for Norwegian methane. The selection of the Deutschneudorf-EUGAL allocation point for the power plants in the Lusatia region was made in consultation with the relevant power plant operator and was confirmed by the latter. Since their commissioning, the import points for LNG have also developed into reliable sources, so that the LNG entry points Brunsbüttel, Mukran and Wilhelmshaven can be considered liquid points. The LNG terminals in Rostock and Stade are still under construction, but according to current plans, they will go into operation before the power plants in Rostock and Mehrum are connected to the grid. This means that these terminals can also be used as allocation points in the modelling.

Furthermore, the use of storage facilities for the supply of power plants with the fDAC product offers the advantage that the source of the stored gas can be freely selected, meaning that all trading points can be selected. Where possible, the gas transmission system operators have chosen several storage facilities as allocation points for a power plant, which significantly increases the availability of methane. In cases where only storage facilities are designated as allocation points, these allocations were agreed with the power plant operators or made at their express request. Storage facilities are therefore generally suitable allocation points for the power plant product, as the availability of gas is sufficiently guaranteed when required.

3.3.1.2 Industry

The future methane requirements of industry were determined as part of the 2025 Scenario Framework through a direct survey of the requirements of industrial customers connected to the gas transmission system up to 2035. Expected developments such as changed processes, efficiency improvements or the substitution of methane by other energy sources, such as hydrogen, were to be taken into account. The demand reported for 2035 was extrapolated to 2037. For industrial customers who did not provide feedback on their future capacity demand, the previous capacity demand figures were extrapolated to 2037.

Regionalisation scenarios 1–3 (2037)

In the approved Scenario Framework, the BNetzA specifies methane capacities of 25 GWh/h (scenario 1), 20 GWh/h (scenario 2) and 31 GWh/h (scenario 3) for the industrial sector for 2037, which covers total sectoral consumption in Germany and includes both industrial sites connected to the gas transmission system and those connected to downstream networks. The BNetzA's overall figures for industry were allocated to the TSO and DSO levels using an allocation key based on historical data for all exit points with recorded demand measurement (RLM) in the Trading Hub Europe (THE) market area during the period from January 2023 to December 2024. Analysis of this data resulted in the following distribution of allocated RLM consumption:

- Exit points with a direct connection to the gas transmission system accounted for 33.9% of consumption.
- Exit points connected to the DSO network accounted for 66.1% of consumption.

This allocation key was applied accordingly to the overall industry figure for scenarios 1–3 for the target year 2037 in order to determine the sector targets for the TSO and DSO network levels.

After the target values had been determined for industry on the gas transmission system, the actual regionalisation was carried out in a multi-stage process:

1. **Future methane supply**
   The first step was to determine the connection points which no longer had to be supplied with methane according to the scenario.
2. **Identification of pipelines that continue to supply methane**
   Identification of pipelines that are (highly likely) to remain methane pipelines by 2037 by the respective gas transmission system operators. Only industrial customers connected to these pipelines are included in the methane scenarios.
3. **Proportional reduction of industrial demand**
   Since the industrial consumers' capacity demand for 2037 determined in the market survey significantly exceeds the sectoral target for the gas transmission system in each scenario, some reductions are necessary. In the third step, the determined capacity demand per scenario and per industrial exit point to be applied was therefore reduced by the same percentage until the sum of all reduced industrial requirements corresponded to the overall figure for the respective scenario for 2037 at TSO level.

In the case of known industrial power plants, i.e. exit points where part of the available capacity is used to supply a power plant whose demand must be allocated to the power plant sector in accordance with the power plant list, the initial capacity was reduced accordingly before step 3 was carried out in order to avoid double counting of the capacity in two sectors.

The Gas NDP database only publishes capacity data for industrial customers located on the gas transmission system (aggregated per gas transmission system operator).

The values to be applied in the distribution system for the industrial sector are taken into account below in the specifications for DSOs (chapter 3.3.1.3). For industrial sites supplied via a distribution system, the applied thermal gas connection rating is therefore not published individually in the Gas NDP database, but is part of the LTF of the DSO operating the relevant supply network.

Regionalisation scenarios 1–3 (2045)

According to the approval of the Scenario Framework, no methane requirements are to be applied in the industrial sector in 2045, meaning that regionalisation is not necessary.

3.3.1.3 Private households, commerce/trade/services, transport, district heating – distribution system operators

In the first quarter of 2024, the gas transmission system operators conducted a survey of the DSOs' LTFs for methane capacity demand in 2025–2035. The reported requirements for 2035 were carried forward by the gas transmission system operators until 2037. The methane capacity demand figures reported by DSOs were checked for plausibility in that reported increases in capacity demand were only taken into account if the DSO provided a comprehensible justification. A key finding of the survey was a reported decline in methane capacity demand of around 26% in the period from 2025 to 2035, partly due to hydrogen meeting some of the demand.

Regionalisation scenarios 1–3 (2037)

In order to transfer the BNetzA's sectoral requirements to the network structure of the gas transmission system operators, a DSO target rating was first determined for each scenario for the group of DSOs, to which the following components were assigned:

- Complete allocation of the private households, commerce/trade/services, transport and district heating sectors, as these end consumers are supplied exclusively via the distribution system level.
- Determination and addition of the share of target rating for the industrial sector supplied via DSO networks in the scenario (chapter 3.3.1.2).
- Determination and addition of the gas connection ratings of power plants supplied via DSO networks that is relevant to the scenario (chapter 3.3.1.1).

The LTFs made by the DSOs are significantly higher than the DSO target values determined for scenarios 1, 2 and 3 for the target year 2037. For this reason, a differentiated adjustment of the LTFs to be applied in 2037 was carried out for each scenario. First, the average relative reduction required for each scenario was determined, by which the sum of all LTF values for 2037 would have to be reduced in order to achieve the DSO target figure for the respective scenario. This average reduction was compared with the LTF reported for each zone. If an LTF curve reported by the DSOs showed a higher relative decline in LTFs between 2025 and 2035 than the average reduction required for the scenario, the LTF reported by the respective DSOs was applied to the zone. The average reduction at which both conditions were met was determined for each scenario.

If the transmission system operators had information about which specific system IPs or zones supply power generating units in the distribution system in the scenario under consideration, the relevant rating was additionally applied to the affected zone without any reduction using the procedure described above.

For scenario 3, which depicts a delayed phase-out of methane compared to scenarios 1 and 2, a further plausibility check of the LTFs for the year 2035 was also carried out. In this case, a methane capacity was carried forward for zones in which the DSOs had reported a complete substitution of methane by hydrogen for 2035 and, accordingly, no methane demand. In the subsequent modelling steps, the corresponding pipelines continued to be taken into account for the methane infrastructure. With this extended plausibility check, the gas transmission system operators use negative planning in scenario 3 for the target year 2037 to ensure that the infrastructure required to supply the DSOs with methane remains available, regardless of the actual supply of hydrogen.

Regionalisation scenario 3 (2045)

According to the approved Scenario Framework, no exit capacities are applied in 2045 in the private households, commerce/trade/services, transport, district heating and industry sectors. The power plants included in scenario 3 (2045) are supplied exclusively via the gas transmission system (chapter 6.3.1.1), meaning that there are no services for connection customers supplied via DSO networks and, accordingly, no regionalisation is required.

3.3.1.4 Cross-border interconnection points

The distribution of methane that can be exported from the German market area via cross-border interconnection points (IPs) determines the capacities available for supplying neighbouring countries. Where cross-border IPs were used as entry points to meet domestic demand, the corresponding exit point of the cross-border IP was not usually included in the balance. The Gas NDP database shows additional cross-border IP exit capacities based on current levels, which were confirmed in the modelling.

Determination of exit capacities for scenarios 1–3 (2037)

For the target year 2037, the BNetzA has set overall figures for cross-border IP exit capacity of 53 GWh/h for scenario 1 and 49 GWh/h for scenarios 2 and 3.

In order to achieve the specified overall figures for Germany as a whole, the gas transmission system operators proportionally reduce the cross-border IPs' exit capacities applied in the balance for the modelling year 2030 in the peak load case until the overall figure is reached. Exceptions are cross-border IPs for supplies to Poland and the Czech Republic, for which a lower proportional reduction in exit capacity was applied for reasons of security of supply. For the Lindau and Kiefersfelden-Pfronten cross-border IPs, modified reductions are applied due to a specific purchase situation in the areas supplied via the two cross-border IPs.

As a result, exit capacities in the balancing case are generally reduced by 33% (scenario 1) and 45% (scenarios 2 and 3) compared to the values assumed in scenario 4 (2030).

Determination of exit capacities for scenarios 1–3 (2045)

For the target year 2045, scenarios 1 and 2 describe a complete phase-out of methane use in Germany, while scenario 3 retains methane for supplying power plants. In addition, all scenarios should show possible transits through Germany to supply neighbouring countries.

With regard to transit, a continuing demand for methane is assumed for neighbouring countries in the east as well as for Austria and Switzerland due to the importance of methane in the energy supply of these countries. Accordingly, exit capacities at the cross-border IPs Deutschneudorf (Czech Republic), Wallbach/Basel (Switzerland), Lasow (Poland) and Oberkappel/Lindau (Austria) are set at 33% of current firm capacities, resulting in a largely uniform linear reduction in exit capacities from 2030 to 2037 to 2045.

3.3.1.5 Storage facilities

Exit capacities for scenarios 1–3 (2037)

To avoid misunderstandings, the gas transmission system operators point out that the Scenario Framework considers the network perspective, which is why the transport directions must also be interpreted from a network perspective. This means that the exit capacity corresponds to the gas injection rate, i.e. the transport direction from the network to the storage facility. Similarly, the entry capacity refers to the gas withdrawal rate, i.e. the transport direction from the storage facility to the network.

Capacities are used in the modelling in accordance with the Gas NDP database ("2025 – NDP 2nd draft" cycle, Capacities tile).

Since the capacity balance in chapter 6.1.1.2 of scenarios 1–3 shows an oversupply in the market area in 2037, the gas transmission system operators assume that it will be possible to fill the storage facility without any restrictions.

3.3.2 Entry capacity

The BNetzA has defined both general and specific requirements for determining methane entry capacity. The key requirement for ensuring security of supply is that the sum of the entry capacities for methane in each load case must at least cover the sum of the exit capacities. For the peak load case, this comparison is presented in chapter 6.1.1.2.

In addition, the BNetzA specifies concrete minimum values for individual input sources – cross-border IPs, LNG, storage facilities – for the respective scenarios and years under consideration in the modelling year 2037, which must be taken into account for the modelling. For the modelling year 2045, only scenario 3 specifies an internal German power demand in the power plant sector. The entry capacity to be determined must therefore be suitable for meeting this power plant demand, in addition to the transits through Germany to supply neighbouring countries, which must be taken into account in all three scenarios. These more specific requirements and their implementation are described in the following chapters.

As part of the negative planning by the gas transmission system operators, it was determined that infrastructure will not be required for methane in specific scenarios and can therefore be converted to hydrogen. Where this infrastructure was also required for the hydrogen modelling of the scenario, it was not taken into account for the modelling of the methane scenario. In cases where this had an impact on the capacity at entry points, this capacity was reduced accordingly in the relevant load cases.

The Gas NDP database contains aggregated values from German gas transmission system operators for the entry points in various modelling variants for the modelling year 2037. This is done explicitly without predetermining the origin of the gas fed into the system.

In view of the predicted decline in methane demand by 2037, the economic viability for infrastructure operators at the entry points is also likely to change. In the course of the conversion to hydrogen, significant adjustments are to be expected both for connection customers for entries and for transmission system operators. These developments will have a noticeable impact on the available entry capacity.

The decisive factor here is the simultaneous demand for exit capacity, which determines the total entries required. Gas transmission system operators strive to maintain close contact with national and European market participants. The aim is to review the assumptions made in future network development plans and to promote the sustainable and plausible development of available entry capacities, taking into account the diversification of supply sources.

3.3.2.1 Cross-border interconnection points

Entry capacities in scenarios 1–3 (2037)

The BNetzA specifies minimum entry capacities of 18 GWh/h for cross-border IPs in scenario 1 and 16 GWh/h for scenarios 2 and 3. Further information can be found in the chapter 6.1.1.2.

Chapter 3.3.3 explains how the freely allocable capacities used in the scenarios are determined.

Entry capacities in scenarios 1–3 (2045)

Due to the advanced transformation, only scenario 3 specifies a remaining domestic methane demand for 2045 to supply power plants with an electrical capacity of 22 GW_e. This corresponds to a gas connection rating of 44 GWh/h. In all 2045 scenarios, methane transit through Germany to supply neighbouring countries and supra-regional biomethane transport must also be taken into account. Cross-border IP entry capacities must be taken into account for the supply of power plants in scenario 3 and the figure for transit through Germany.

For this specific 2045 scenario, it is assumed that the German market area will be supplied mainly from Denmark (Ellund), Norway (Emden, Dornum), the Netherlands (Bocholtz, Elten, Oude Statenzijl), Belgium (Eynatten) and France (Medelsheim). This assumption is based on the methane and biomethane production, LNG and transport infrastructure available in these countries, which already ensures today that the German methane demand of the market area is primarily met by supplies from these countries.

3.3.2.2 Storage

The BNetzA requires the gas transmission system operators to take into account the minimum entry capacities specified in the licence for each scenario, amounting to 42 GWh/h for scenario 1 and 37 GWh/h for scenarios 2 and 3 in 2037. Furthermore, transmission system operators are required not to take storage locations for methane and hydrogen into account twice, unless it is a newly built storage facility or individual caverns are converted for hydrogen operation.

The BNetzA also defines minimum requirements for hydrogen storage facilities, which must be supplemented, if necessary, by additional grid-supportive locations or the necessary entry and exit capacities as part of the hydrogen modelling process. The minimum requirements are based on specific reports on new storage projects and/or storage conversions from the WEB 2024 survey. To identify further sites, the authority refers in particular to existing cavern storage facilities for methane, the study on potential "Hydrogen storage facilities" [BVEG/DVGW/INES 2022] and other projects with suitable project status reported in the market survey.

To ensure that the same storage infrastructure is not used for modelling both methane and hydrogen, the gas TSOs and hydrogen transmission system operators first checked whether storage projects that must be taken into account in hydrogen to meet the minimum requirements, or that could be taken into account in addition to the minimum requirements, are newbuild or conversion measures. In the case of a conversion measures, it was then checked whether the storage facilities in question were connected to the gas transmission system and whether, and to what extent, these storage facilities could still be taken into account for methane.

Entry capacities in scenarios 1–3 (2037)

The BNetzA requires the transmission system operators to take into account the minimum entry capacities specified in the licence in the respective scenarios (scenario 1: min. 42 GWh/h; scenarios 2 and 3: min. 37 GWh/h).

Further information can be found in chapter 6.1.1.2.

Entry capacities in scenarios 1–3 (2045)

In 2045, only scenario 3 assumes entry capacities from storage facilities, which will secure the supply of the power plants specified in the scenario. Based on the geographical distribution of the power plants and the resulting regional demand, corresponding entries from the storage facilities are assumed.

Further information can be found in chapter 6.3.1.3.

3.3.2.3 LNG terminals

For LNG entry points, the gas transmission system operators are obliged to take into account the minimum capacities specified in the licence for each scenario for the year 2037, amounting to 16 GWh/h for scenario 1, 14 GWh/h for scenario 2 and 79 GWh/h for scenario 3.

Entry capacities in scenarios 1–3 (2037)

For the Gas and Hydrogen Network Development Plan 2025, the transmission system operators have received capacity reservations/capacity expansion claims in accordance with Sections 38 and 39 of the GasNZV for the planned LNG terminals in Brunsbüttel, Lubmin, Mukran, Rostock, Stade and Wilhelmshaven amounting to 79.7 GWh/h, which are included in scenario 3 as requested.

Chapter 3.3.3 explains how the freely allocable capacities used in the scenarios are determined.

Further information can be found in chapter 6.1.1.2.

Entry capacities in scenarios 1–3 (2045)

According to the Scenario Framework approval, no LNG entry capacities are assumed for 2045.

3.3.2.4 Domestic production

In the draft Scenario Framework, the gas transmission system operators proposed estimating the conventional methane entry capacity from domestic production based on the most recent forecast of the German Association of Natural Gas, Oil and Geoenergy (BVEG). In addition to the baseline forecast, the BVEG also considers alternative scenarios, such as the "Forecast 2024+ Development". This scenario assumes additional production volumes from development projects and the continued operation of the Großenkneten plant until 2040. Compared to earlier estimates, this approach predicts a less severe decline in production volumes. The baseline forecast, which is based on data from the BVEG's 2023 outlook, shows a moderate decline after 2029. As the baseline forecasts tended to be more reliable in the past, the focus on this data is deemed appropriate. The BNetzA has approved this approach in its approval of the Scenario Framework. When modelling domestic production, gas transmission system operators are required to use the overall figures for the individual scenarios and years under consideration, as presented in the approval of the Scenario Framework.

Entry capacities in scenarios 1–3 (2037)

For the reference year 2037, an entry capacity of 1 GWh/h is assumed in scenarios 1, 2 and 3, respectively.

Entry capacities in scenarios 1–3 (2045)

In the reference year 2045, no domestic production is taken into account in scenarios 1, 2 and 3.

3.3.2.5 Biomethane

The BNetzA does not specify concrete values for the individual scenarios for biomethane entry capacity. However, it points out that the assessment of the development of biomethane entries should be carried out as described in the "Draft Scenario Framework for the Gas and Hydrogen Network Development Plan 2025" using more recent information, such as the 2024 monitoring report by the BNetzA and the Federal Cartel Office (BKartA).

The draft Scenario Framework included an analysis of the current situation and an assessment of the development of biomethane entries using the 2023 monitoring report by the BNetzA and the Federal Cartel Office (BNetzA/BKartA 2023) as well as the biomethane feed-in atlas published by the German Energy Agency (dena) (dena 2023). For the biomethane feed-in plants in operation, it was proposed that these be regionalised on the basis of the feed-in atlas. The dena feed-in atlas also contains information on biomethane processing plants that are under construction or planned.

These sources reflect the current status and development of biomass plants throughout the methane network, i.e. at both the transmission and distribution system levels. In the past, gas transmission system operators have used only the entry capacities of biomethane plants connected to their gas transmission systems as input variables for modelling. The capacities of biomethane plants connected to the DSOs' networks were not specifically considered. In addition, there is insufficient information about which distribution systems they are connected to. However, this information is not necessary for modelling, as the DSOs must take these biomethane plants into account for their LTFs. As a result, biomethane plants in the DSO networks reduce the exit capacity required from the upstream networks. This also reduces the LTF levels.

Entry capacities in scenarios 1–3 (2037)

Gas transmission system operators base their modelling solely on biomethane plants connected to their networks. This includes both biomethane plants already in operation and newly planned biomethane plants. In 2025, approximately 500 MWh/h of entry capacity will be connected to the gas transmission system operators' networks. Current plans indicate that this capacity will grow to approximately 650 MWh/h by 2035. These values are used in all three scenarios for the year 2037.

Entry capacities in scenarios 1–3 (2045)

Due to the high level of uncertainty, the gas transmission system operators are refraining from specifying concrete entry capacities from biomethane plants in gas transmission systems for 2045. However, the topic of biomethane is described qualitatively for 2045.

3.3.3 Determining sufficient level of freely allocable methane entry and exit capacity

3.3.3.1 Regulatory basis

The gas transmission system operators determine the entry and exit freely allocable capacity (FAC) for the THE market area in accordance with the BNetzA's KARLA 2.0 and ANNIKA rulings ("Capacity regulations and handling of network access in the gas sector – KARLA Gas 2.0", ref. BK7–24-01-007 (KARLA Gas 2.0) and "Determination on the recognition of instruments for increasing capacity ANIKA", ref. BK7–23-043 (ANIKA)). Capacity-increasing measures such as load flow commitments (LFCs) or market-based instruments (MBIs) may only be used to achieve a sufficient level of FACs.

Since MBIs must be used in the H-gas network to provide the capacities offered, the sufficient level of FACs thus represents an upper limit for marketing. From the gas transmission system operators' perspective, there is no contradiction to the so-called "maximisation requirement" in KARLA Gas 2.0, operative part 3 (b). This regulates the obligation to cooperate with the aim of maximising available FACs. However, as soon as fee-based instruments are required to achieve a sufficient level of FACs, maximisation is only permitted up to this level (ANIKA, operative parts 1 and 4).

The sufficient level is understood to mean "the required amount of available capacity at entry and exit points in each case" (ANIKA, margin note 35). This amount must be determined precisely. Capacities with restricted use are not included in the sufficient level of FACs.

Paragraph 2 of the ANIKA ruling stipulates that the sufficient level of FACs is determined by the current market-wide long-term capacity demand, which is determined by the gas transmission system operators in the NDP process in accordance with Section 15a of the Energy Industry Act (EnWG) as part of a transparent, non-discriminatory NDP process across all network operators, using the criteria previously applied in Section 17 sentence 2 of the GasNZV. The capacity demand is incorporated into the network modelling of the Gas and Hydrogen Network Development Plan and thus forms a basis for any necessary network expansion measures.

Due to the imminent end of L-gas use, long-term L-gas demand is only determined as part of the market area conversion. There are no plans to use capacity-increasing instruments.

In the Gas and Hydrogen Network Development Plan 2025, the following criteria were applied in accordance with Section 17 sentence 2 of the GasNZV to determine the future sufficient level of FACs for H-gas. This approach is in line with the gas transmission system operators' proposal in chapter 3.2.11 of the draft Scenario Framework for the Gas and Hydrogen Network Development Plan 2025 [KO.NEP 2024], even though no successor regulation for Section 17 of the GasNZV has been adopted since the GasNZV expired.

1. The expected development of the ratio of methane supply and demand is based on the scenarios in chapter 2 and the evaluation of booking behaviour at the entry and exit points.

2. The annual auction on 7 July 2025 marked the start of the 2025–2027 incremental capacity cycle, which surveyed the long-term binding capacity demand of network users within the scope of Regulation (EU) 2017/459 (NC CAM). No relevant non-binding market requests were made for this incremental capacity cycle. The survey therefore has no impact on the sufficient level of FACs.

3./4. The findings from load flow simulations and existing or predicted bottlenecks in the network in accordance with KARLA Gas 2.0 Section 3 (b) were generated by means of modelling of the gas transmission system in the Gas and Hydrogen Network Development Plan 2025 and have been incorporated into the H-gas balance. If the bottlenecks are permanent and cannot be resolved by capacity products or network expansion measures in accordance with KASPAR, LFCs or MBIs, they may have a negative impact on the long-term FAC availability.

5. In order to capture capacity demand developments during the year, the results of the capacity allocation procedures in the gas year (GY) 2024/2025 were evaluated and taken into account in determining the sufficient level. The result of the annual auction for capacities in accordance with NC CAM has also been available since July 2025 but did not yield any deviating findings.

6. Findings about the denial of network access pursuant to Section 25 sentences 1 and 2 EnWG are reviewed by the gas transmission system operators on a regular basis as part of the Gas and Hydrogen Network Development Plan 2025. Findings from auction surcharges in auctions for primary capacities are taken into account in the determination of long-term capacity demand. This process is explained in more detail in chapter 3.3.3.4.

7. The possibilities for increasing capacity by cooperating with neighbouring transmission or distribution system operators were reviewed as scheduled in the Gas and Hydrogen Network Development Plan 2025.

8. The market areas were merged in 2021. The findings about the resulting capacity demand levels have been taken into account since that time.

9. The findings from the TYNDP 2025 in accordance with Art. 32 (EU) 2024/1789 for the necessary capacities at cross-border IPs have been taken into account for the long-term capacity demand and have been incorporated into the H-gas capacity balance.

10. Existing and rejected capacity reservations pursuant to Section 38 of the GasNZV and corresponding connection requests pursuant to Section 39 of the GasNZV are presented in chapter 3.2.1 of the draft Scenario Framework for the Gas and Hydrogen Network Development Plan 2025 [KO.NEP 2024].

In the light of the long-term capacity demand and the need for a sufficient level of FACs, the BNetzA expects gas transmission system operators to first explore economically reasonable capacity-increasing measures when modelling the Gas and Hydrogen Network Development Plan 2025 in order to increase the availability of FACs until a sufficient level is achieved.

Given the decarbonisation target stipulated in Section 3 of the Federal Climate Action Act (KSG) and the associated shorter remaining useful lives of gas transportation assets, any new construction measures for the methane network must be reviewed to ensure that they are compatible with the objectives of the EnWG.

In this context, it should be noted that an offer of entry FACs that exceeds the required capacity can result in network expansion measures or increased MBI costs due to (excessive) flexibility in intermediate load cases.

In addition to customer demand as shown by bookings, the required demand for entry FACs to serve the exit FACs actually used must also be taken into account. An increase in consumption (e.g. due to market area conversion) can therefore lead to an increase in the required scope of entry FACs. Conversely, the decline in consumption assumed in the scenarios of the Gas and Hydrogen Network Development Plan 2025 after 2030 can lead to a reduction in the required scope of entry FACs.

Adjusting the FACs to a sufficient level ensures an appropriate level of MBIs and network expansion. The potential for MBI use is not reduced by such an adjustment of capacities, as interruptible capacities can also be used for MBIs.

In accordance with ANIKA paragraph 2, the sufficient level of FACs is determined as part of the NDP in accordance with Section 15a EnWG, i.e. in a process lasting at least two years. This makes it possible to respond to changes in the market environment. In future, the level should be determined as far as possible as part of the Scenario Framework creation process.

The transmission system operators reserve the right to extend the period for evaluating the results of the capacity allocation procedures (criterion 5) in future in order to have a broader statistical basis. This year, only GY 2024/2025 was used, as the earlier periods show atypical market behaviour as a result of the war in Ukraine and are not representative of future market behaviour.

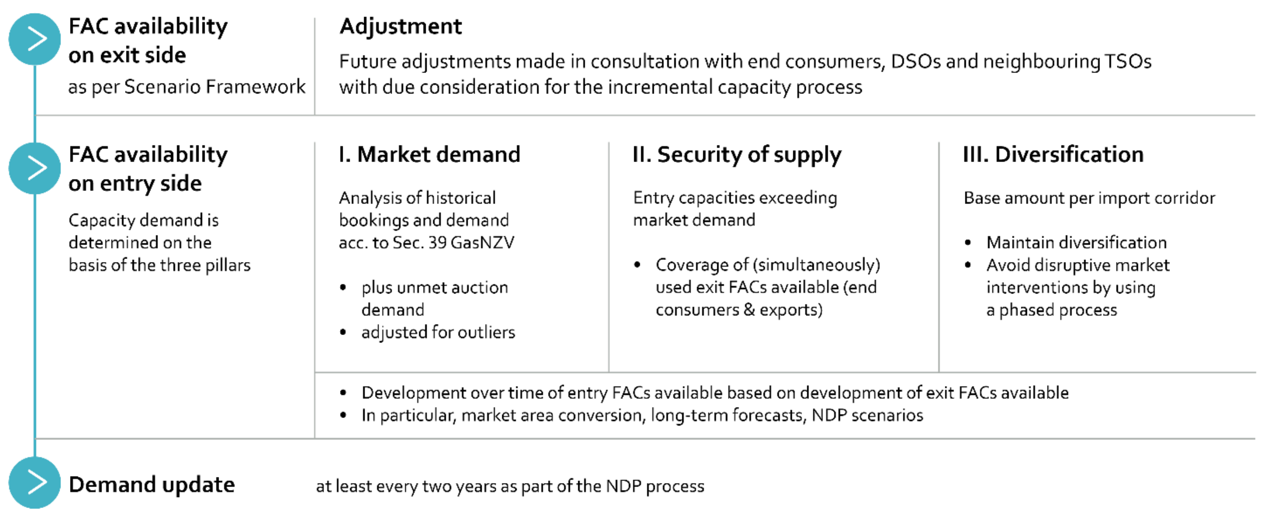
3.3.3.2 Methodology for determining the sufficient level

The methodology for determining the sufficient level of FACs is described below. The FACs are determined for each individual point for the years up to and including 2033 in order to cover the period of the upcoming annual auctions. As mentioned above, determining the sufficient level of FACs on a regular basis in future may lead to changes in the capacity available up to 2033 in response to changing market demands.

The gas transmission system operators do not consider it appropriate to specify the sufficient level of FACs beyond 2033, as the scenarios in the Gas and Hydrogen Network Development Plan 2025 show a possible range of developments, and forecasts of market behaviour are subject to considerable uncertainty. The networks offer flexible options for distributing the total demand for FACs for each individual point, taking into account both national and European developments. A point-specific level beyond 2033 would not reflect this flexibility. Rather, it could influence future developments in the market.

The methodology for determining the sufficient level of FACs can be simplified as follows:

Figure 5: Methodology for determining the sufficient level of FACs



Source: Coordination Office for Gas and Hydrogen Network Development Planning

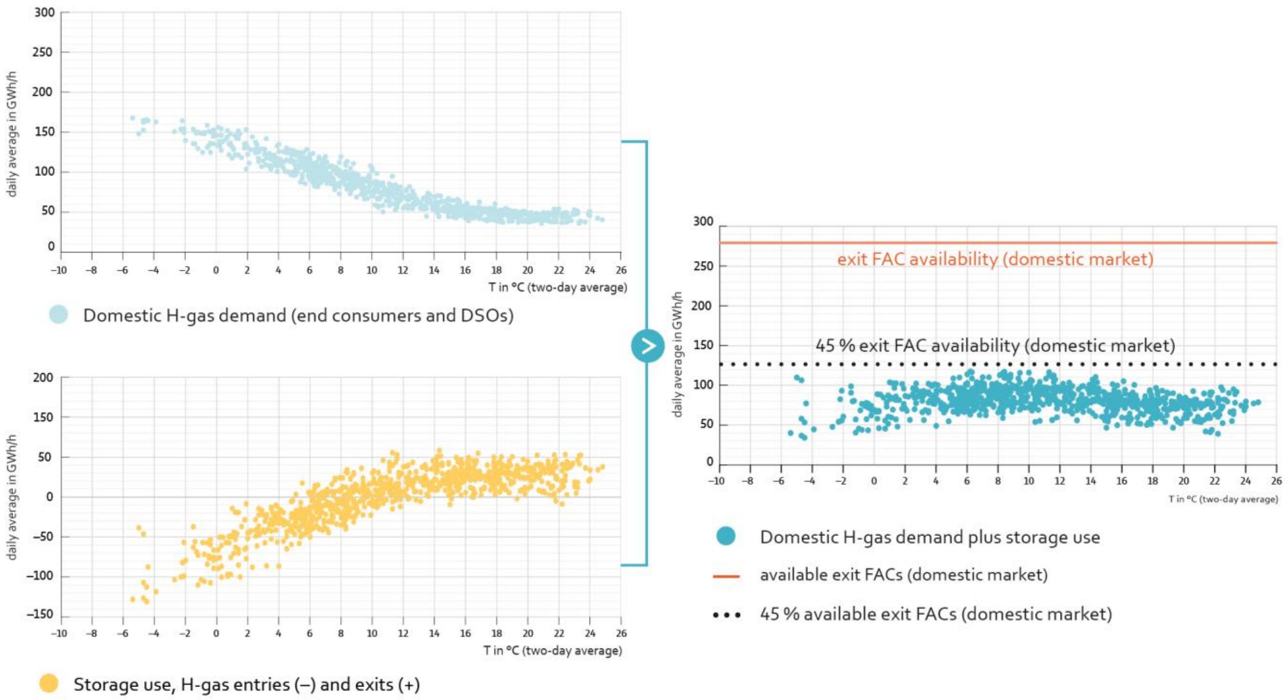
3.3.3.3 Sufficient level of exit FACs

The sufficient level of exit FACs basically corresponds to the development over time, as shown in the Scenario Framework for the Gas and Hydrogen Network Development Plan 2025. In isolated cases, adjustments were made for end users or DSOs where updated information made this necessary.

On the domestic side, the required capacity depends on the demand of end users (industry and power plants) and DSOs, taking into account the forecast development over time (including new connections to the gas transmission systems). In addition, there is a need to fill gas storage facilities. This is offset by the storage facilities' entry capacity into the transmission network, which contributes to serving the FAC exits.

Both storage facilities and domestic demand show temperature-dependent usage in total. Statistical evaluations show that the simultaneous domestic FAC off-take, taking into account the additional storage facility usage, is below 45% of the contractual FAC supply for end users and DSOs:

Figure 6: Simultaneous domestic consumption including storage use



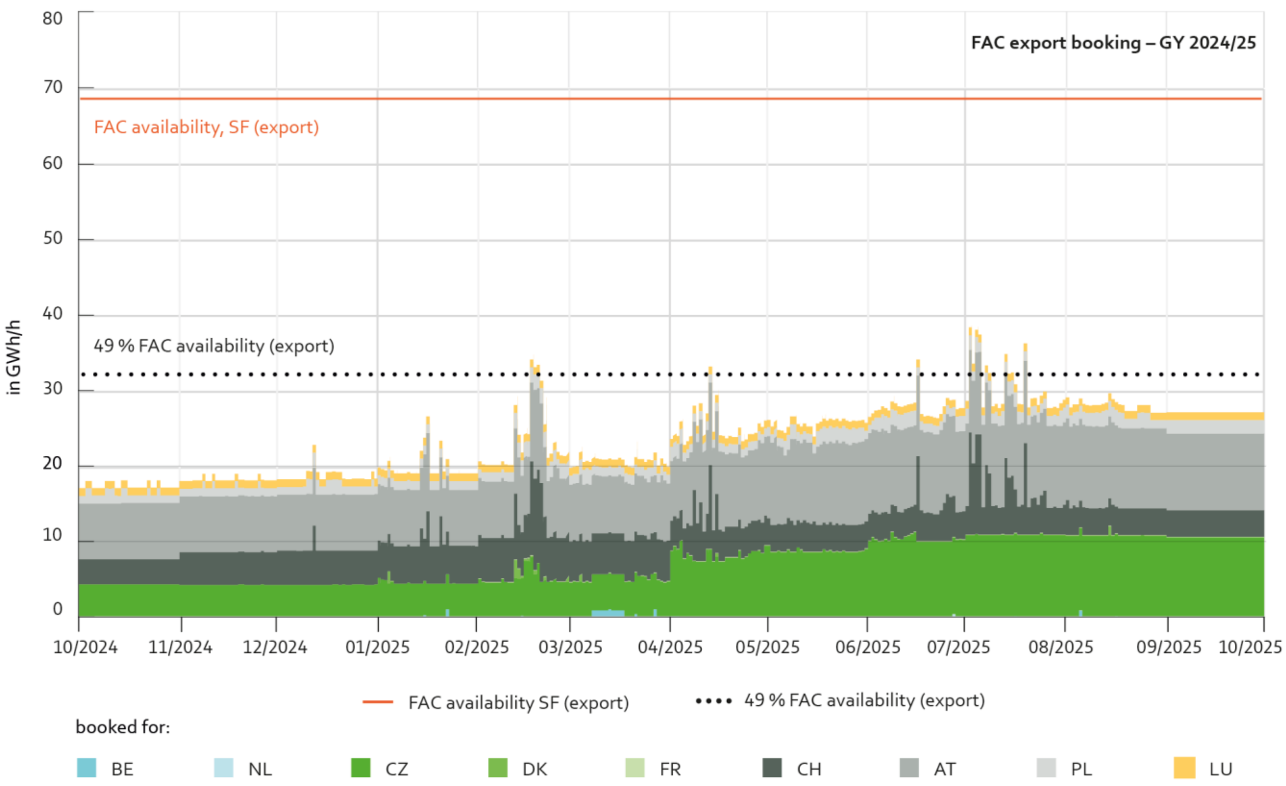
Source: Coordination Office for Gas and Hydrogen Network Development Planning

Foreign demand for exit FACs relates to exports from Germany. Analyses of FAC bookings for exports via cross-border IPs show that simultaneous utilisation is significantly below FAC supply.

Excluding outliers (96.2% quantile, i.e. exclusion of 14 days), less than 49% of the FAC supply was booked for exports at the same time.

It should be noted that levels may be exceeded in midsummer, i.e. in temperature ranges where domestic consumption plus storage drops below the annual maximum demand (Figure 6).

Figure 7: Simultaneous FAC export bookings in GY 2024/2025



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Even if the simultaneous demand for exports is below the supply, the sufficient level of FACs for each individual point corresponds to the development set out the Scenario Framework, as the maximum utilisation of the individual cross-border IPs occurs at different times. Maintaining the export FACs also makes sense from a European market integration perspective and in terms of security of supply for neighbouring countries.

The export FACs will continue to be adjusted with due consideration for the needs of shippers (incremental capacity process) and in coordination with neighbouring European transmission network operators.

In summary, it can be stated that the FACs available for each of the entry points will not be adjusted, even if the simultaneous demand is below the total supply over the whole year. However, lower simultaneous use has an impact on the amount of entry FACs actually required.

3.3.3.4 Sufficient level of entry FACs

The sufficient level of entry FACs in total is adjusted to the development of exit FACs and represents the maximum defined by market demand, supply and diversification, whereby the criteria also allow for a point-specific determination of the required capacity:

I. Market demand: at least cover the historical bookings, adjusted for extreme values

II. Supply: also cover *simultaneously used* exit FACs (domestic consumption and export)

III. Diversification: at least provide a base amount (percentage share of current FACs) per VIP/import route – maintain import routes and increase in flexibility

Market demand for cross-border IPs is determined on the basis of bookings and auction surcharges. This approach takes into account at least the historical bookings (for each point per VIP/import corridor), including unfulfilled auction requirements ("day ahead"/"within day"), adjusted for extreme values. Cross-border IPs for which there is no VIP obligation are grouped together into import corridors for reasons of non-discrimination.

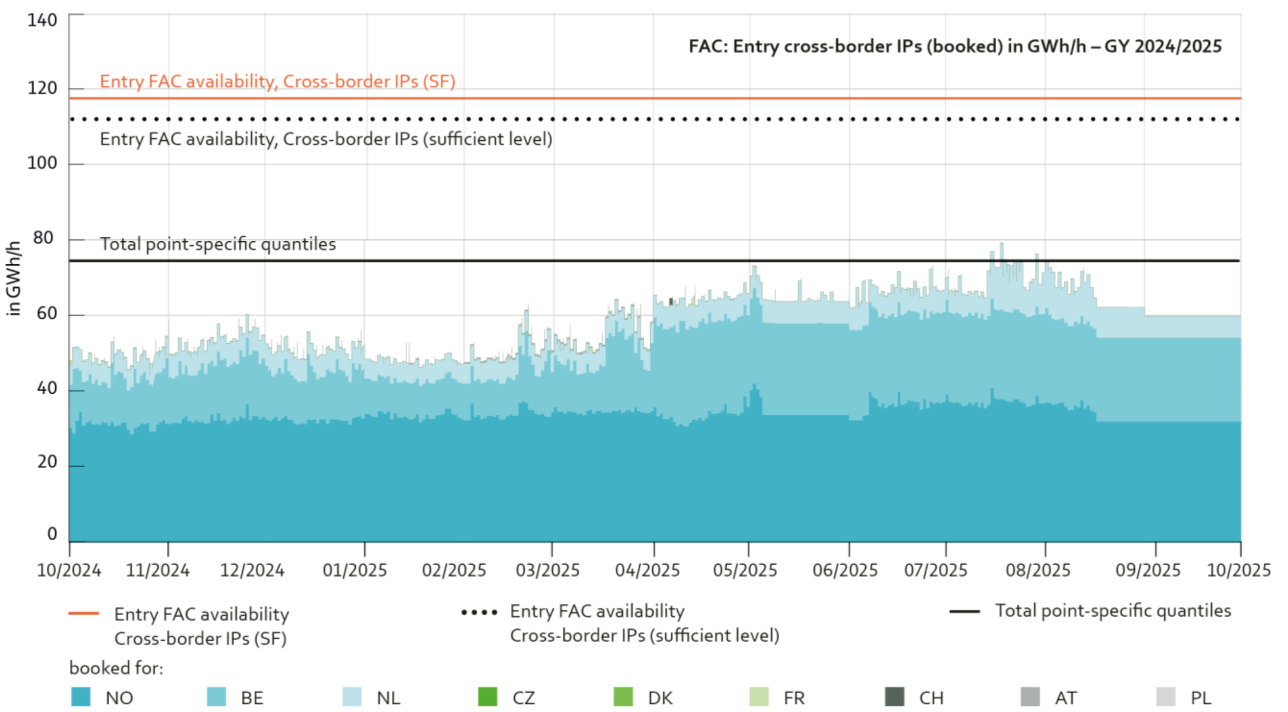
An analysis of historical data shows that the maximum simultaneous entry booking is significantly lower than what is on offer. From the gas transmission system operators' perspective, a reduction is therefore feasible without restricting market requirements and their flexibility, as both the amount of entry FACs required and the actual need for flexibility are reflected in the shippers' booking behaviour. Pure declarations of intent that do not lead to actual bookings and short-term booking peaks (a few hours/days) do not demonstrate a long-term capacity demand. The analysis of historical data was carried out in August 2025 so that the results could still be incorporated into the network modelling.

Currently, as with the consideration of FAC exports, the point-specific target value is set at a minimum of the 96.2% quantile of (entry) bookings per import route. Flexibility for customers is maintained, point-specific demand is met and is significantly above the average booking. The level of the quantiles is regularly reviewed as part of the NDP process in order to adapt them to changes in market demand.

The future availability of point-specific entry FACs at cross-border IPs is de facto higher than the 96.2% quantile, as criteria II (supply) and III (diversification) show a higher entry demand, which is additionally distributed across the points. This generally reduces the exclusion of extreme values to less than 5.5 days (instead of 14 days). This corresponds to the 98.5% quantile per import route.

Figure 8 shows the aggregated FAC entry bookings at cross-border IPs plus unmet auction requirements for GY 2024/2025 in comparison to current and future demand.

Figure 8: Market demand for FAC entries at cross-border IPs compared to supply



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Bookings were mainly made at the import points to Belgium, the Netherlands and Norway. The remaining import corridors were used to a significantly lesser extent.

At the same time, demand for bookings is significantly below supply throughout the year. Despite higher consumption, the winter half-year, with an average utilisation rate of less than 50% of supply, actually shows even lower use of entry FACs than the summer half-year. Even though there were no extreme cold spells in the winter of 2024/2025, this behaviour shows that high load cases in winter are mainly covered by the market through the use of storage facilities.

A year-round supply of entry FACs, which should only be used to cover peak load demand on a few days at most, would therefore not be appropriate, especially since on such days of high consumption, entry capacities that are only available on an interruptible basis throughout the year can also be transported securely. Rather, such a supply would lead to increased costs due to network expansion or MBI deployment to ensure reliable provision of FACs even in intermediate load cases.

The methodology described above for determining the minimum point-specific FAC demand at cross-border IPs (entries) cannot yet be applied to other point types at this stage.

The LNG market in Germany is still developing. Capacity growth is expected in the coming years based on the connection requests received by the gas transmission system operators by the end of 2025 in accordance with Section 39 of the GasNZV. There is therefore no reliable booking data available for entry points at LNG terminals.

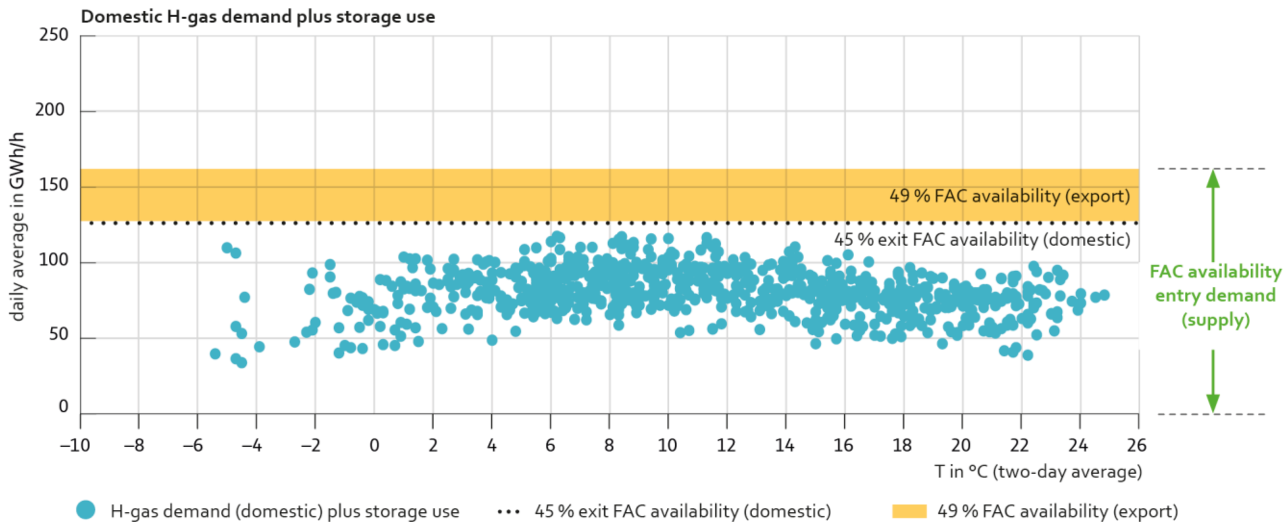
Consequently, the sufficient level of entry FACs for LNG will initially be determined on the basis of developments in the Scenario Framework. Adjustments to the Scenario Framework will only be made on the basis of changed assumptions regarding the commissioning of the onshore LNG terminals in the Wilhelmshaven and Unterelbe clusters.

A similar approach is taken for entry FACs at storage facilities, which account for only a small proportion of total entry FACs. However, these storage facilities show high utilisation (especially to cover winter demand) and also contribute to year-round flexibility in the German network.

The procedure described for the point-specific determination of FAC market demand at entry points (criterion I, market demand) must be reviewed regularly in the coming years, with due consideration for updated information from neighbouring infrastructure operators and future connection customers. Once the LNG market has consolidated, an approach similar to cross-border IPs is conceivable for these points.

Beyond this point-specific market demand, for reasons of security of supply (criterion II, supply), it must be ensured that the simultaneous existing FAC exit demand can be covered via FAC entries. For this purpose, simultaneous domestic consumption plus storage facility usage (Figure 6) and simultaneous export demand (Figure 7) are also examined.

Figure 9: FAC entries (sufficient level) to serve FAC exits



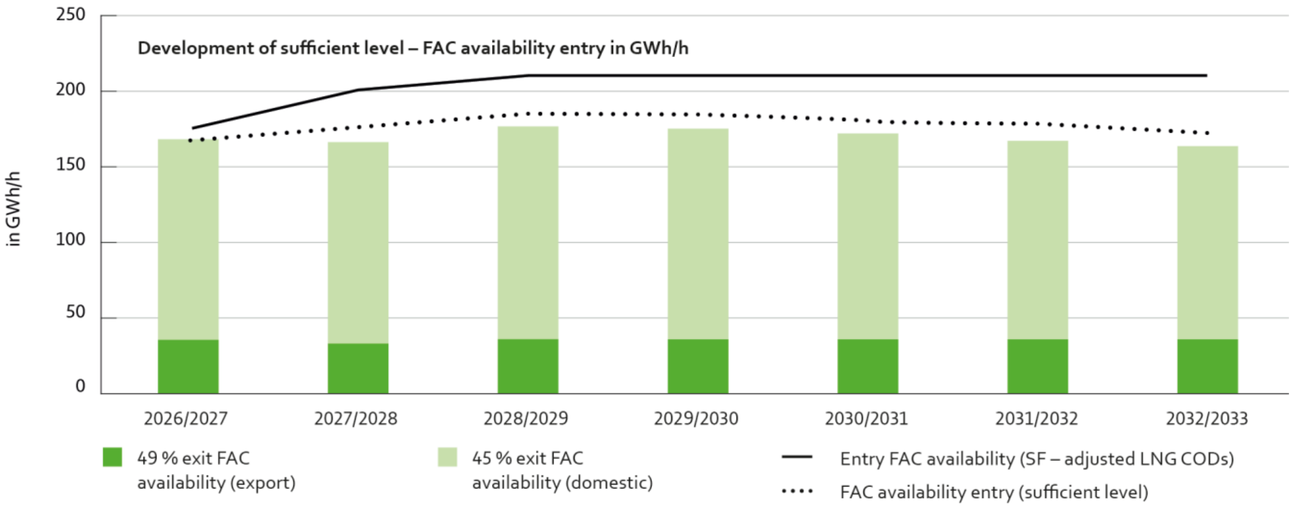
Source: Coordination Office for Gas and Hydrogen Network Development Planning

The sum of simultaneous demand for FAC exits for domestic consumption and export exceeds the market demand determined on the basis of GY 2024/2025 (criterion I, market demand). Since entry FAC at LNG terminals and storage facilities is already taken into account in accordance with the Scenario Framework, the demand for entry FAC exceeding market demand is distributed proportionally among the cross-border IPs. The resulting future supply of FAC at entry points significantly exceeds the market demand reflected in bookings (Figure 8). Based on the percentage shares of domestic consumption and exports, the demand for FAC entries required can be adjusted to the temporal development of FAC exits.

Individual import corridors have recently shown very low utilisation. However, it cannot be ruled out that import demand via these corridors will rise again. To ensure the resilience of supply and increase flexibility, a baseline demand (criterion III, diversification) per corridor that decreases over time is therefore also taken into account. This will, in particular, avoid disruptive changes when the methodology presented here is applied for the first time. The base demands applied will be reviewed in future in terms of their level and development over time on the basis of updated empirical values.

For the Gas and Hydrogen Network Development Plan 2025, the sum of the sufficient level of entry FACs will develop as shown in Figure 10.

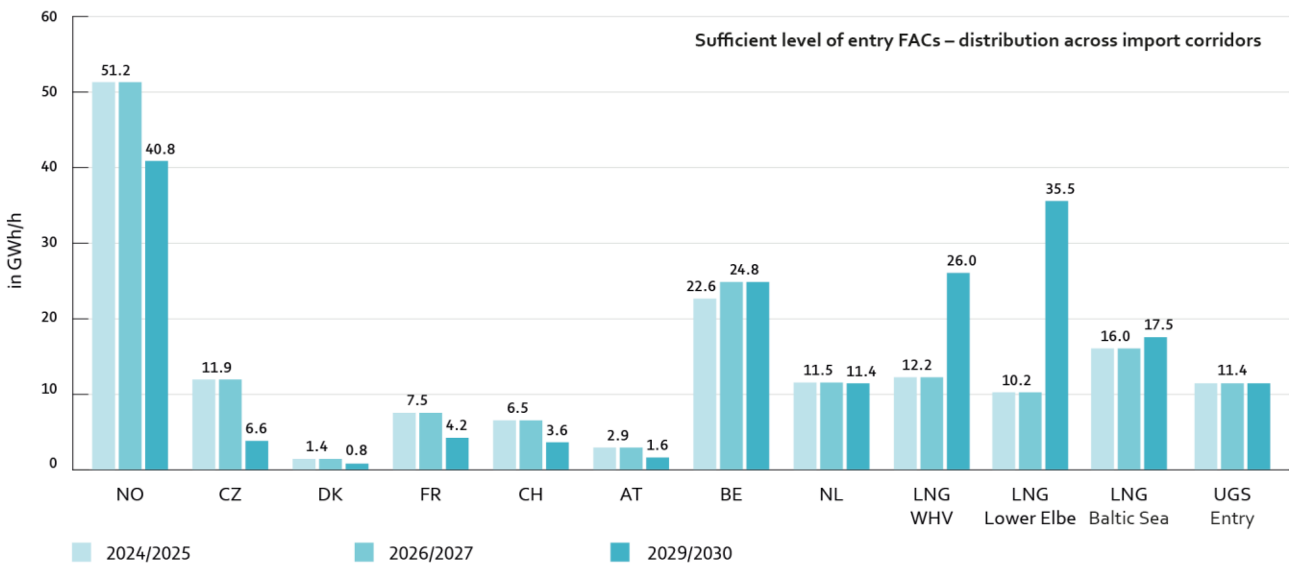
Figure 10: Sufficient level of entry FACs compared to the Scenario Framework – shares of cross-border IPs, LNG and underground storage facilities (UGS)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Changes in the market environment may lead to adjustments to this development in future network development plans. **Fehler! Verweisquelle konnte nicht gefunden werden.** shows the distribution of entry FACs across the various import corridors for the GY 2024/2025, 2026/2027 and 2029/2030. Import corridors with an entry capacity of less than 0.5GWh/h are not shown. The precise values for all import corridors for the period up to 2033 can be found in the Gas NDP database for the Gas and Hydrogen Network Development Plan 2025.

Figure 11: Development of entry FACs per import corridor



Source: Coordination Office for Gas and Hydrogen Network Development Planning

The increase at the VIP Belgium is due to high utilisation of bookings and unmet auction requirements in GY 2024/2025. Even under the new methodology, the allocation in GY 2026/2027 is almost identical to the availability (supply) of entry FACs in GY 2024/2025. The methodology presented here is therefore consistent with the previous availability of entry FACs. However, the more differentiated consideration of the relationship between methane supply and demand in accordance with Section 17(1) of the GasNZV will lead to adjustments in later years. In particular, there will be shifts between import corridors due to the commissioning of new LNG terminals, without a corresponding increase in exit requirements.

Despite the reduction, almost all FAC bookings for GY 2024/2025 can also be shown in GY 2029/2030. For example, in the Norway import corridor, the supply in GY 2029/2030 covers 98.5% of historical demand for bookings – only on 5.5 days would additional interruptible bookings of less than 1 GWh/h be necessary.

The proactive involvement of neighbouring infrastructure operators and regulatory authorities has not yet been possible at this stage, as the proposed methodology must be communicated simultaneously and without discrimination to all market participants in accordance with ANIKA. The gas transmission system operators are grateful for the constructive feedback from market participants as part of the consultation on the Gas and Hydrogen Network Development Plan 2025 in order to further optimise the methodology for determining the sufficient level of FACs in future network development processes.

In future, information from these stakeholders regarding planned developments that are not reflected in the current utilisation of FAC capacities will be taken into account for the determination of point-specific import requirements. This applies in particular to import points that are currently underutilised. If the information is plausible and/or verifiable, this may lead, for example, to an individual adjustment of the FAC baseline capacities or to a conversion between FACs and other company capacity products.

An adjustment of the FAC offer at LNG terminals is to be examined in subsequent years if the capacities offered are not (sufficiently) booked or if the infrastructure operators' plans change.

3.3.3.5 Conclusion on the sufficient level

The methodology presented for determining the sufficient level of FAC meets the criteria set out in the EnWG, KARLA Gas 2.0 and ANIKA: the adjustments of the FAC to the sufficient level ensure an appropriate level of MBI use and network expansion. They do not reduce the potential for MBI use, as interruptible capacities can also be used for MBIs.

Flexibility and complete coverage of the FAC exits used are maintained even after the entry FAC has been reduced, taking into account conditionally firm, freely allocable capacity (cFAC) at storage facilities. Even in peak load cases, simultaneous demand can be met so that there is no capacity shortfall even during periods of high network loads – see chapter 5.4 (H-gas balance) for more information.

In future, the methodology for determining the sufficient level of FACs will be applied exclusively to H-gas, as MBI-relevant bottlenecks only occur there.

The sufficient level of FAC for the auction-relevant period up to 2033 is published in the Gas NDP database as part of scenario 4 (reference year 2030). Information on scenarios 1, 2 and 3 for the reference year 2037 should only be considered indicative. The Gas NDP database only provides a total value for these years.

The Gas and Hydrogen Network Development Plan consultation also allows for short-term alignment with neighbouring countries in accordance with Art. 6 NC CAM, if necessary. However, long-term changes in cross-border demand can also be incorporated into the following network development plans.

In individual cases, additional limited or dynamic entry products may already be offered at this stage in order to compensate for the reduction in freely allocable entry capacities. Further reviews of this kind are planned for the revised draft of the Gas and Hydrogen Network Development Plan 2025.

3.4 Input variables for hydrogen

3.4.1 Results of the 2024 market survey on hydrogen projects

From 7 February 2024 to 22 March 2024, the German electricity transmission system operators and hydrogen transmission system operator conducted the first joint market survey on hydrogen projects

(WEB survey) in the "2024" cycle. The aim of the survey was to gather up-to-date information on transportation requirements for projects currently underway and on future hydrogen production plans. This includes reports from market participants and DSOs on PtG plants, hydrogen storage and use, and electricity consumption by large consumers. A total of 1,731 projects (plus PtG plants) were reported. After a plausibility check, 1,600 of the reported hydrogen projects were taken into account for the next stage of the process. Of the 300 PtG projects reported, 298 projects were taken into account after plausibility checks.

3.4.2 Detailed sector allocation of hydrogen projects

In the 2024 market survey, market participants reporting hydrogen projects were free to assign them to several demand sectors (power plants, industry, transport and CTS). At the same time, the BNetzA specified Germany-wide capacities for individual sectors in its approved 2025 Scenario Framework. For the modelling approach used in the Gas and Hydrogen Netzwrk Development Plan 2025, it waws necessary to establish a clear allocation of the capacities reported in the hydrogen project submissions of the market survey to the respective demand sectors. The following assumptions were made for this purpose:

- A reported project was generally considered a power plant for any scenario if it was assigned to the power plants sector in the market survey. In addition, this project had to be included as a power plant in this scenario in the BNetzA power plant list.
- If a reported hydrogen project was also listed under the industrial sector, there was a check as to whether a "remaining capacity" of this project report could be allocated to the industrial sector. To this end, plausible efficiencies for the power plants were used to check whether the power plant capacity in accordance with the BNetzA power plant list already covered the reported hydrogen project from the market survey. If this was not the case, a "remaining capacity" was allocated to the industrial sector.
- If a hydrogen project was reported for both the transport and CTS sectors, the capacity in these two sectors was not taken into account.
- A reported project was only included in the industry sector for any scenario if demand in the market survey had been allocated to the industry, transport and CTS sectors in the market survey.
- A reported project was only included in the transport sector for any scenario if demand in the market survey had been allocated to the transport and CTS sectors.

Using this approach, projects were clearly allocated to the demand sectors for each scenario.

3.4.3 Exit capacity

3.4.3.1 Power plants

The different hydrogen scenarios are based on the electrical capacities specified in the BNetzA location list.

Scenario 1 (2037)

The power plant projects identified in the joint market survey were taken into consideration in accordance with the location list published by the BNetzA. Both the specific locations and the electrical capacities of 29 GW_e were specified. The required gas connection ratings for the individual locations were taken from the results of the market survey.

The ratio between electrical capacity and thermal capacity was then checked for plausibility for the power plant projects recorded. In cases where this ratio was outside an appropriate efficiency range (25% to 65%), the thermal capacity was adjusted. If it was above the defined permissible range, the upper limit of

65% was applied, and if it was below the appropriate range, the lower limit of 25% was used. This procedure gave a thermal capacity of 61 GW_{th} for these power plants.

Scenario 2 (2037)

The power plant projects identified in the joint market survey were taken into consideration in accordance with the location list published by the BNetzA. Both the specific locations and the electrical capacities of 41 GW_e were specified. The required gas connection ratings for the individual locations were taken from the results of the market survey.

The ratio between electrical capacity and thermal capacity was then checked for plausibility for the power plant projects recorded. In cases where this ratio was outside an appropriate efficiency range (25% to 65%), the thermal capacity was adjusted. If it was above the defined permissible range, the upper limit of 65% was applied, and if it was below the appropriate range, the lower limit of 25% was used. This procedure gave a thermal capacity of 87 GW_{th} for these power plants.

Scenario 3 (2037)

The power plant projects identified in the joint market survey were taken into consideration in accordance with the location list published by the BNetzA. Both the specific locations and the electrical capacities of 5 GW_e were specified. The required gas connection ratings for the individual locations were taken from the results of the market survey.

The ratio between electrical capacity and thermal capacity was then checked for plausibility for the power plant projects recorded. In cases where this ratio was outside an appropriate efficiency range (25% to 65%), the thermal capacity was adjusted. If it was above the defined permissible range, the upper limit of 65% was applied, and if it was below the appropriate range, the lower limit of 25% was used. This procedure gave a thermal capacity of 11 GW_{th} for these power plants.

Scenarios 1–3 (2045)

The electrical capacity specified by the BNetzA in scenario 1 for the year 2045 amounts to 60 GW_e. In scenario 2, the capacity is 81 GW_e. Scenario 3 also has a capacity of 81 GW_e, which, in contrast to scenario 2, is composed of capacities from methane and hydrogen-fired power plants. Scenario 3 is based on the assumption that newly built methane power plants with CCU/CCS will be in operation in 2045. The electrical capacity of these power plants amounts to 22 GW_e. Accordingly, the overall figures specified are a capacity of 22 GW_e for methane and a capacity of 59 GW_e for hydrogen. For hydrogen, all power plant projects from the market survey are therefore taken into consideration, minus those projects which the transmission system operators could assign to the locations of the new construction measures.

Since only power plant projects with an electrical capacityt of around 50 GW_e were reported in the joint market survey for hydrogen, the BNetzA stipulates that the f hydrogen transmission system operators must make up the difference to the overall figure by adding further capacities in suitable locations for the hydrogen network.

Depending on the scenario, this results in varying capacity differences, which must be compensated by the hydrogen transmission system operators providing additional power plant capacities in order to meet the requirements of the Scenario Framework.

Existing conventional power plant sites were used to identify additional power plant capacities. Due to their existing infrastructure and their previous importance to the energy industry, these sites are particularly suitable for conversion to hydrogen. Three site categories were defined for systematic classification:

- Category 1: Locations of newbuilds in accordance with Sections 38, 39 GasNZV with capacity reserves
  These sites, which are currently still supplied with methane, will be connected to the hydrogen infrastructure and also offer additional potential for further power plant capacities. The analysis is based on the difference between today's higher electrical capacity and the lower electrical capacity assigned in the respective scenarios based on the specifications in the BNetzA site list.
- Category 2: Power plant sites from the hydrogen core network
  As part of the work on the hydrogen core network, the hydrogen transmission system operators have identified additional power plant sites that were not specified in the market survey and are therefore not on the BNetzA site list. As these sites have been taken into consideration for the hydrogen core network, it can be assumed that they are gird-supportive sites from the future hydrogen infrastructure perspective.
- Category 3: Other coal and methane-fired power plants
  Also taken into consideration were sites where coal or methane-fired power plants are currently in operation but are no longer expected to be connected to the grid in 2045. These sites appear suitable given the electricity infrastructure at coal-fired power plants and the additional gas infrastructure at methane-fired power plants.

Depending on the difference in capacity, the additional power plant capacities and locations identified in this way were assigned to a category (in the order of category 1, category 2 and category 3) for each scenario until there was no longer any difference. All power plants were assigned within a category; if necessary, only part of the capacity was assigned.

3.4.3.2 Industry

The industrial sector has been taken into account in scenarios 1–3 for hydrogen. The specified overall figure for hydrogen demand varies both between scenarios and between the years under consideration. The procedure described below basically follows the same pattern; only for scenario 3 in 2037 was a slightly different approach chosen.

Scenarios 1 and 2 (2037)

For scenarios 1 and 2, the hydrogen projects reported in the market survey were used as a basis. In this regard, the BNetzA stated in its approval of the Scenario Framework 2025 that regionalisation *"should be based on data from the hydrogen market survey and that projects with a higher probability of execution should be taken into account in the modelling."*

In accordance with this requirement, the projects reported for the industrial sector were used in accordance with the project status. More advanced projects were given priority until the specified overall figure was reached. If the cumulative capacity of the hydrogen projects of an additional project status exceeded the specified overall figure, the capacities of the projects of the last status considered were adjusted proportionally so that the overall figure was adhered to.

Scenario 3 (2037)

In this scenario, the overall figure for industrial hydrogen demand is significantly lower than in the other scenarios. In principle, the approach here is also based on the project status of the reported industrial hydrogen projects. If the specified overall figure is exceeded by the inclusion of an additional project status, the capacities of the projects of the last project status used are not adjusted proportionally, but rather they are based on the commissioning of the pipelines to which the hydrogen projects can be connected.

Scenarios 1–3 (2045)

The procedure for scenarios 1–3 for the reference year 2045 is essentially the same as the procedure for scenarios 1 and 2 for 2037. For the year 2045, the specified overall figure for industrial hydrogen demand in the scenarios exceeds the demand reported for all industrial projects. In this case, the capacities of all industrial projects were adjusted proportionally until the overall figure was reached.

3.4.3.3 Private households, commerce/trade/services, transport

The private households, commerce/trade/services and transport sectors are only taken into account in scenario 1 for hydrogen. The approach here is identical for the years 2037 and 2045:

Private households

The market survey included hydrogen projects that were assigned to the power plants sector without there being any electrical capacity (district heating only). These project reports are not included in the BNetzA power plant list. These are heating plants, which were subsequently taken into account for the PHH sector. The total capacity determined in this way is below the demand threshold required for this sector in the approved 2025 Scenario Framework for both 2037 and 2045. The required remaining capacity was distributed proportionally across all LTFs for hydrogen reported by the DSOs.

Commerce/trade/services

The reported hydrogen projects assigned to the CTS sector were taken into account in full. The total capacity determined in this way is below the demand threshold required for this sector in the approved 2025 Scenario Framework for both 2037 and 2045. The required remaining capacity was distributed proportionally across all LTFs for hydrogen reported by the DSOs.

Transport

The reported hydrogen projects assigned to the transport sector were taken into account in full. The total capacity determined in this way is below the demand threshold required for this sector in the approved 2025 Scenario Framework for both 2037 and 2045. The required remaining capacity was distributed proportionally across all LTFs for hydrogen reported by the DSOs.

3.4.3.4 Cross-border interconnection points

For cross-border IPs, the approved Scenario Framework contains different overall figures and regionalisation requirements for the individual scenarios and support years on the hydrogen exit side. They all refer to Table 24 of the Scenario Framework draft ("baseline capacities" for hydrogen capacities at cross-border IPs).

Scenarios 1–3 (2037)

For the reference year 2037, Table 1 of the approved Scenario Framework contains the requirement for all scenarios to "determine what capacity can be achieved without expansion". The results obtained in response to this question are shown in chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**.

Scenarios 1–3 (2045)

For the reference year 2045, Table 1 of the approved Scenario Framework specifies 30 GWh/h for all scenarios. In principle, the BNetzA confirms the capacities proposed by the transmission system operators in Table 24 of the draft Scenario Framework. The exception here are the cross-border IPs to the Czech Republic. Instead of setting 6.6 GWh/h for the exit capacity in Deutschneudorf and Waidhaus, as proposed, a total capacity of 6.6 GWh/h must be used for the Czech Republic.

The hydrogen transmission system operators have complied with this requirement by allocating the entire 6.6 GWh/h to the Waidhaus cross-border IP.

3.4.3.5 Storage facilities

The approved Scenario Framework does not contain an explicit overall figure for exit capacities to storage facilities – i.e. for injection into storage – in any of the scenarios or support years. Instead of an overall figure, Table 1 contains the stipulation that the "exit capacity [...] must be in an appropriate ratio to the entry capacity so that the storage facility can be filled completely."

The exit capacity provided was used for the projects reported in the market survey. For storage capacities above this level, the hydrogen transmission system operators used the ratio deemed appropriate by the BNetzA in the approved 2025 Scenario Framework (75%).

3.4.4 Entry capacity

On the hydrogen entry side, Table 2 of the approved Scenario Framework contains the overall figure as a minimum value for all scenarios and support years, with the proviso that the "sum of the hydrogen entry capacities [...] must cover at least the sum of the hydrogen exit capacities in each load case".

This provision is implemented by the hydrogen transmission system operators in different ways according to the load case logic (chapter 3.4.5). Therefore, the overall figures for each sector are presented below.

3.4.4.1 Cross-border interconnection points

On the entry side, the approved Scenario Framework contains for cross-border IPs very similar overall figures and regionalisation requirements across all scenarios and support years. As on the exit side, reference is also made to Table 24 of the Scenario Framework draft ("base capacities" for hydrogen capacities at cross-border IPs) [BNetzA 2025].

Scenarios 1 and 2 (2037)

For scenarios 1 and 2, the overall figure for entries at cross-border IPs is defined as "at least 58 GWh/h".

Scenario 3 (2037)

For scenario 3, "at least 10 GWh/h" is to be applied for entries at cross-border IPs.

Scenarios 1–3 (2045)

In the modelling year 2045, the requirement for entries at cross-border IPs for all three scenarios corresponds to the "at least 58 GWh/h" already specified for 2037 in scenarios 1 and 2.

Given the high exit capacities projected for scenarios 1–3 in 2045, entry capacities at cross-border IPs will need to increase significantly. A description of the methodology used to determine the additional entry capacity potential is provided in chapter 6.4.1.2 .

3.4.4.2 Storage

For storage facilities, the approved Scenario Framework contains overall figures on the entry side as well as requirements for regionalisation.

The overall figures are also described as minimum values for storage facilities, with the proviso that the "sum of the entry capacities for hydrogen [...] in each load case must at least cover the sum of the exit capacities for hydrogen". Here, too, the hydrogen transmission system operators follow the stipulation in different ways according to the respective load case logic from chapter 3.4.5 . This applies in particular to the *Kalte Dunkelflaute* load case (periods of very low wind and solar capacity), as explained by the BNetzA.

Scenarios 1 and 2 (2037)

For scenarios 1 and 2, the overall figure for entries from storage facilities into the transmission network is defined as "at least 36 GWh/h".

This number is filled up, as required, on a pro-rata basis for 2037 from reported projects of the joint market survey for hydrogen projects that have reached at least the "basic design/regional planning procedure" status (i.e. excluding "initial assessment/feasibility study" and "project idea"), taking into account the specific features of the individual load cases. The correction made by the BNetzA to the entry and exit capacities and the gas withdrawal and injection rates is adopted.

Scenario 3 (2037)

For scenario 3, a minimum of 6 GWh/h is to be used for entries from storage facilities into the transmission network for the year under consideration (2037). The procedure is basically the same for scenarios 1 and 2 (2037), but differs for different load cases.

Scenarios 1–3 (2045)

In the modelling year 2045, the requirement for entries from storage facilities into the transmission network in all three scenarios corresponds to the already specified "at least 36 GWh/h" requirement.

Given the high exit capacities projected for scenarios 1–3 in 2045, projects that are at the "initial assessment/feasibility study" and/or "project idea" stage are also taken into account along with the plans reported as part of the joint market consultation for projects already considered for 2037, which must have reached at least the "preliminary planning/regional planning procedure" stage. This means that all hydrogen projects are taken into account, regardless of their current planning status. The corrections made by the BNetzA to the entry and exit capacities, or rather the storage withdrawal and injection capacities, are adopted.

Even when storage projects are fully taken into account, total entries from storage facilities, combined with the entries into the transmission network at cross-border IPs and from other imports – which are likewise assumed to be at full capacity for the year 2045 – remains insufficient to ensure a balance between entries and exits in all load cases across scenarios 1–3. It may be assumed that, subject to appropriate market developments, the storage sites included in the joint market consultation offer additional potential for increasing entries into the transmission system. For this reason, all storage projects in scenarios 1–3 have been "over-estimated" to varying degrees in each case to ensure system balance in every scenario. Further details are provided in chapter 6.4.1.2 .

3.4.4.3 Other imports (including LH_2 and derivatives)

Similar to cross-border IPs and storage facilities on the entry side, the "Other imports (including LH_2 and derivatives)" sector also contains overall figures with minimum values and regionalisation requirements. These can also be found in Table 2 of the approved Scenario Framework.

The regionalisation of the overall figure is based on projects reported by the joint market survey as required by the approved Scenario Framework.

Scenarios 1 and 2 (2037)

For scenarios 1 and 2, the overall figure for entries via "Other imports (including LH_2 and derivatives)" is set at "at least 4 GWh/h".

Projects reported in the joint market survey that have been assigned at least the "basic design/regional planning procedure" status (or higher) are to be used to fill up this number.

This is done by the hydrogen transmission system operators on a pro-rata basis, taking into account the specific features of the individual load cases.

Scenario 3 (2037)

For scenario 3, a minimum of 1 GWh/h is to be used for entries via "Other imports (including LH_2 and derivatives)" for the year under review (2037). Again, the procedure for filling the numbers is basically the same as for scenarios 1 and 2 (2037) and differs for the different load cases.

Scenarios 1–3 (2045)

In the modelling year 2045, the requirement for entries via "Other imports (including LH_2 and derivatives)" in all three scenarios corresponds to the already specified "at least. 4 GWh/h" requirement.

Given the high exit capacities in scenarios 1–3 in 2045, projects that are at the "initial assessment/feasibility study" and/or "project idea" stage are also taken into account along with the plans reported as part of the joint market consultation for projects already considered for 2037, which must have reached at least the "preliminary planning/regional planning procedure" stage. Accordingly, all hydrogen projects are taken into account, regardless of their current planning status.

3.4.4.4 Electrolysis

The electrolysis capacities in the scenarios are based on the BNetzA's requirements and are derived from the long-term scenarios, while the joint market survey of hydrogen and electricity transmission system operators serves as a basis for the regionalisation of electrolysis capacities.

Using the market survey, the BNetzA has compiled a consolidated list of electrolysers, which provides a joint project base for the individual scenarios. For this project base, the BNetzA relies on the consolidated project status groups of the draft Electricity Scenario Framework. These are divided into five groups and combine the status of a project as reported in the network operator survey and in the joint market survey. All projects except those in the "idea and preliminary planning" status group are included in the project base. Based on this methodology, the joint project base thus comprises a total of 32 GW_e, and projects with a total electrical capacity of 56 GW_e are outside the joint project base.

The electrolyser capacities specified in the scenarios are based either on the orientation scenarios of the long-term scenarios for scenario 2 or on the BNetzA's own reflections (scenarios 1 and 3). The BNetzA justifies this approach, among other things, by stating that the deviations are within the range specified in the anchor points of the system development strategy. This strategy envisages an entry capacity of 30 GW_e to 40 GW_e for 2035 and an entry capacity of 60 GW_e to 80 GW_e for 2045.

The BNetzA's approval of the Scenario Framework does not contain any information on gas entry capacities for electrolysers. The hydrogen transmission system operators therefore carried out a plausibility assessment of the ratio between electrical capacity and thermal capacity for the electrolyser projects recorded. Where this ratio fell outside a reasonable efficiency range of 40% to 75%, the thermal capacity was adjusted. If the ratio was above the defined range, the upper limit of 75% was applied. Where the ratio was below the reasonable range, the lower limit of 40% was used instead.

Scenario 1 (2037 and 2045)

For scenario 1, the BNetzA has specified an electrical capacity of 32 GW_e as the minimum value for modelling for the years 2037 and 2045. Using the specified minimum value, the gas transmission system operators are to determine the specific entry capacity required in the two years under consideration as part of the modelling exercise. If more entry capacity is required than the minimum level, the remaining projects outside the joint project bases are to be used to further regionalise the entry capacity.

Scenario 2 (2037 and 2045)

For scenario 2, the BNetzA uses the overall figures from the long-term scenario "O45 electricity" of 42 GW_e for 2037 and 58 GW_e for 2045.

The joint project base described above, with a total capacity of 32 GW_e, forms the starting point in both years under consideration and must be taken into account in full. As in scenario 1, the hydrogen transmission system operators must also use the remaining projects outside the joint project base to further regionalise the capacity in order to achieve the overall figures mentioned above. This should involve locating the electrolysers where they will be most useful to overall network operation, with due consideration for already known electrolyser locations.

The hydrogen transmission system operators have based their selection of electrolyser locations on the likelihood of the projects being executed. To this end, the project status reports provided by the project sponsors in the joint market survey were used. It was assumed that more advanced projects were more likely to be completed.

In addition to the projects in the joint project base, projects with the "Basic design/regional planning procedure" project status were taken into account for 2037. In order to achieve the capacities exactly as specified, the capacities of the electrolysers in the last project group included were adjusted by a factor.

In 2045, the projects from the joint project base were fully taken into account and those with the "Basic design/regional planning procedure" status were also included. Furthermore, projects with the project status "initial assessment /feasibility study" were included with adjusted capacity.

Scenario 3 (2037 and 2045)

For scenario 3, the BNetzA specifies a minimum value of 6 GW_e for the year 2037. This value was determined by the BNetzA taking into account the specific conditions of scenario 3. In particular, this scenario assumes a delayed hydrogen ramp-up and a less extensive phase-out of methane for the year 2037.

Projects from the project base that have the consolidated "In operation" or "Execution" status were taken into account. In addition, projects with the "Advanced planning" status with adjusted capacity were included.

The BNetzA specifies a minimum value of 32 GW_e for the year 2045. The specified minimum value is intended to help gas transmission system operators determine the specific entry capacity required in the two years under consideration as part of their modelling. If the entry capacity required exceeds the minimum value, the remaining projects outside the joint project base are used to further regionalise the entry capacity.

3.4.5 Load cases for hydrogen modelling

This section describes the load cases developed and applied uniformly for flow-dynamic testing of transportation requirements as part of the hydrogen modelling process. A load case describes a specific transportation task with defined modelling premises that are considered for the simulation and design of a system. Uniform load cases have already been used for the modelling of the hydrogen core network 2032. For hydrogen modelling in the Network Development Plan 2025, the hydrogen transmission system operators have revised the system based on the findings from the modelling for the core network. In addition to the hydrogen core network modelling, a further load case is being introduced to specifically examine the grid-supportive use of storage facilities.

3.4.5.1 Description of load cases

The following load cases were used to test and design the hydrogen network for different requirements:

- *Entry tests* are performed to determine the extent to which regional maximum hydrogen quantities can be shipped across different regions. The load case is intended to explore the limits of flow mechanics in the network and simulate long transportation paths (variation of sources). A total of three entry zones – northwest, east and south – are tested here, resulting in three entry load cases.
- The methodological approach underlying the entry test is expanded to examine the *gird-supportive use of storage facilities*, i.e. the extent to which *storage facilities can support network operation* when it comes to coping with high levels of renewable generation. In view of the substantial storage potential in the northwest entry zone, this load case has been selected for the assessment of the network-supporting role of storage sites.
- The *Kalte Dunkelflaute* security of supply case looks at the extent to which a very high nationwide gas demand resulting from low temperatures and low renewable energy generation can be covered by the hydrogen network, primarily from storage facilities and via imports. This case defines the maximum gas load on the exit side to ensure supply security (maximum withdrawals).
- The *high renewable energy storage* load case is intended to represent a scenario of maximum hydrogen supply from intermittent renewable sources or from a surplus of electricity, while ensuring that storage facilities are utilised to the greatest possible extent in support of the network.

A total of five load cases are considered in the hydrogen modelling:

- Entry test in the east
- Entry test in the south
- Grid-supportive use of storage facilities, Entry test in the northwest (EEbNW)
- Kalte Dunkelflaute
- High level of renewable energy storage

3.4.5.2 Classification of load cases from a gas industry perspective

The *entry test* load case examines the maximum deployment of entries in a region in conjunction with a high network load in the most remote region. From a flow-mechanical perspective, a region represents an interconnected network area in which entries act on the same transportation paths (congestion or high-load network area). This generates the largest possible transportation task with maximum transportation distances. The aim of this approach is to examine the extent to which capacities are freely allocable at entry points and to determine the infrastructure requirements (pipelines, compressors, etc.) for this transportation task. In order to model restrictive but realistic load cases, an additional distinction is made on the exit side: Exits in close proximity to the entries generally have a relieving effect (grid-supportive effect), whereas exits at greater distances increase the load on the system (restrictive transportation effect). Due to this effect, in entry test cases, exit points close to the entries are assumed to have a relieving effect while the exits far from the entry points are assumed to increase the load (high performance levels, e.g. requested values/input data).

For industry and CHP plants, the hydrogen transmission system operators made modelling assumptions for baseload demand (i.e. demand with a load-relieving, network-supporting effect) based on statistical analysis. These analyses drew on current consumption data from the methane sector. The results indicated that, in the industrial sector, 35% of demand can be regarded as baseload demand, while for CHP plants the corresponding figure is 20%.

Based on the findings on modelling and determining the core hydrogen network, three entry zones (northwest, east, south) were identified for modelling entry test cases for the Gas and Hydrogen Network Development Plan 2025. These regions are shown in the following overview.

Figure 12: Classification of entry zones based on identified high-load transportation paths in regions (schematic representation)

Source: Coordination Office for Gas and Hydrogen Network Development Planning

The *Kalte Dunkelflaute* security of supply load case is intended to examine the extreme case of very high demand for electricity and heat at very low temperatures and weather-related failure of intermittent, renewable energy sources. It is assumed that electricity consumption will be covered predominantly by power plants, in particular combined heat and power (CHP) plants. Therefore, exits for power plants, CHP plants and industry, with the exception of storage facilities, will be maximised throughout the entire network area, while entries will only be provided by import sources, non-volatile other feed-in projects and storage facilities. The system balancing is achieved by further grid-supportive use of storage facility and pro-rata entries at cross-border IPs. The potential of the storage facility and import services as well as their impact on the network *("grid-supportive use")* were taken into account.

The *gird-supportive use of storage facilities* load case represents a maximum supply of hydrogen from intermittent generation or from the electrolysis of a surplus of renewable electricity, while at the same time making gird-supportive use of storage facilities. For the basic model, a distinction is made between increasing and decreasing the load on network areas, as in the entry test. In contrast to the entry test, the transportation task is lessened here by the changed use of storage facilities. This is achieved through withdrawals from the storage facility in the entry zone that take place not at full capacity but at reduced capacity, so feeding less into the network. The reduced withdrawal from storage into the grid is equal to the entries from intermittent sources. This simulates the grid-supportive use of the storage facilities in the entry zone. In the entry zone, the test case assumes not only maximum withdrawal from storage into the network, but also the storage of excess hydrogen. This reduces the total amount to be transported in the entry zone.

3.4.5.3 Load cases for the years 2037 and 2045

As part of the modelling for the Gas and Hydrogen Network Development Plan 2025, the security of supply load case *Kalte Dunkelflaute* and the load cases *entry test in the northwest*, *entry test in the east* and *entry* *test in the south* were modelled for all scenarios to be examined and evaluated in terms of expansion requirements. In the course of the modelling, the *entry test in the northwest* proved to have a particularly adverse impact on the network. In order to ensure the efficiency of any network expansion, the above system of gird-supportive use of storage was applied to the *entry test in the northwest* for all scenarios and years considered (*grid-supportive use of storage facilities* load case). The key element of this approach is the beneficial potential of flexible and gird-supportive cavern storage capacities in the northwest entry zone, which are not available to the same extent in the other entry zones.

Table 7: Proportions of total entry and exit capacities applied in the load cases

Load case	Zone	Inclusion of entry and exit points in the scenarios and the respective share of capacity in the load cases by zone										
		Factored into all scenarios									Only in scenario 1	In all scenarios
		Storage		Cross-border IPs		CGTs	CHPs	Industry	PHH/ CTS	Transport	PtG	other
		Entries	Exits	Entries	Exits	Exits	Exits	Exits	Exits	Exits	Entries	Entries
Entry test for the east/south entry zones and northwest entry test (grid-supportive use of storage facilities)	East/south entry zone	100%		100%							100%	100%
	Entry zone grid-supportive use (northwest)	100% less PtG entries*		100%							100%	100%
	Relevant load zone		100%		100%**	100%	100%	100%	100%	100%		
	System balancing***		0% to 100%		0%**	0% to 100%	20% to 100%	35% to 100%	0% to 100%	0% to 100%		
	Baseload		0%		0%**	0%	20%	35%	0%	0%		
Kalte Dunkelflaute	Germany	100%	0%	100%	0%	100%	100%	100%	100%	100%****	0%	100%*****
High level of RE storage	Germany	0%	100%	0% to system balancing	0%	0%	60%	35%	0%	0%	100%	100%

Abbreviations/acronyms used for entry and exit points: IP = (cross-border) interconnection point, CGT = power plant, CHP = combined heat and power units, PHH = Private households, CTS = commerce/trade/services sector, PtG = Power-to-Gas (electrolysis), other = other intermittent and non-intermittent energy sources
* In the *grid-supportive use of storage facilities* load case, the entries from storage facilities in the entry zone is reduced by the volatile entries from electrolysis plants (PtG) and other entries.
** Exits for 2037 at cross-border IPs that do not require expansion are determined in chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**. For the year 2045, the maximum exit flows from the individual IPs to other countries is allocated to the load cases with entry zones. The exits occur outside the respective entry zone and are based on the respective load zones as well as the greatest possible transmission distance.

*** Entry / exit balancing occurs at the edge of the load zone by applying exit capacity on a pro-rata basis.

**** The modelling for 2045 does not take the transport sector into account during *Kalte Dunkelflaute* because this consumption group was assumed to be flexible (e.g. through the use of on-site storage).
***** The load case is only based on non-volatile other entry capacity.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Status of Network Expansion Measures

4

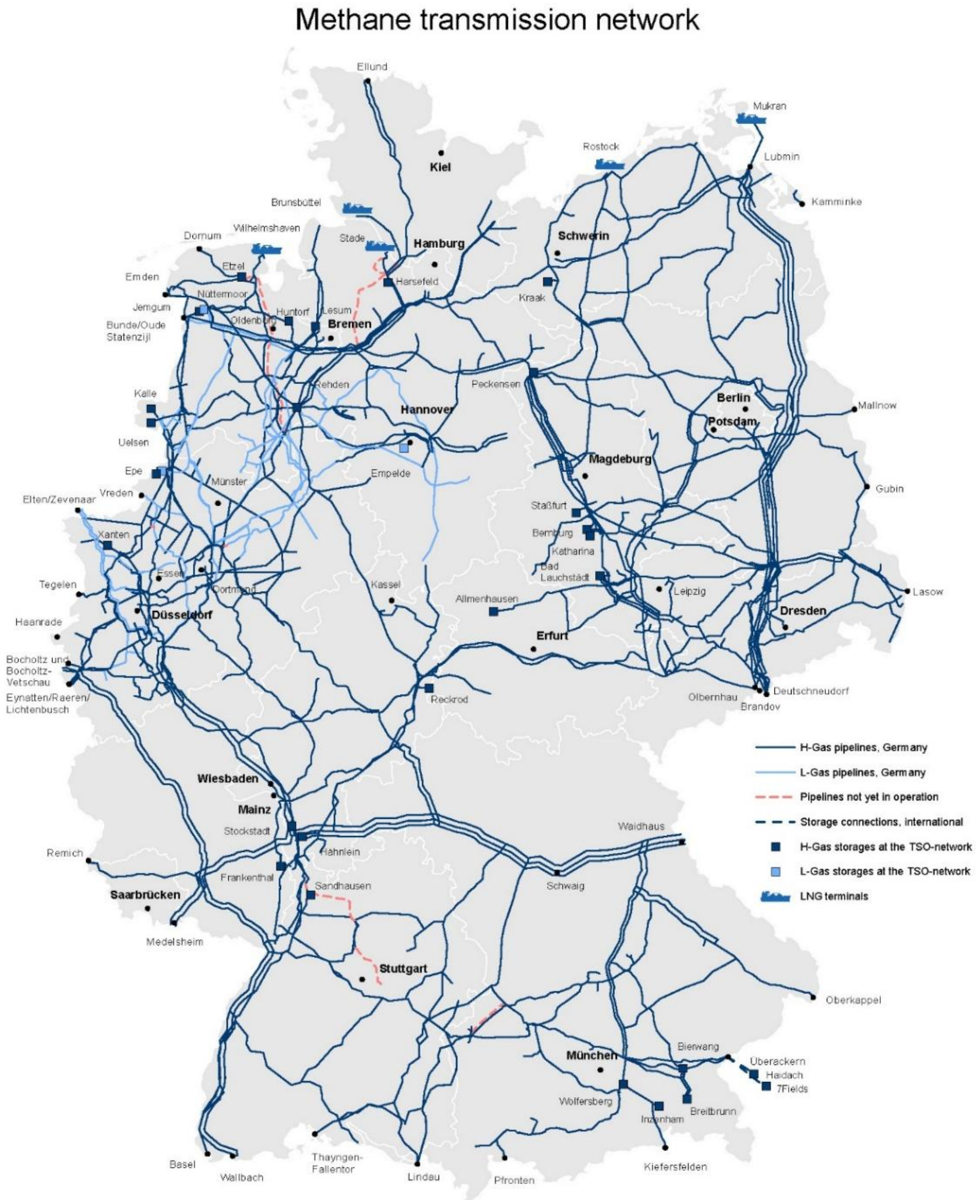
4 Status of Network Expansion Measures

Chapter 4.1 provides an overview of the gas transmission network as on 1 September 2025, while chapter 4.2 describes the starter network used for modelling the Gas and Hydrogen Network Development Plan 2025. Chapter 4.3 gives an update on the network expansion measures of the Gas Network Development Plan 2022–2032. This chapter 4 thus fulfils the requirements of Section 15c (2) EnWG regarding information to be provided on the status of implementation.

4.1 Methane gas transmission system and hydrogen network as of 1 September 2025

The German gas transmission network is divided into an H-gas network and an L-gas network. These two transmission networks are shown in the following figure.

Figure 13: Methane transmission network



Source: Coordination Office for Gas and Hydrogen Network Development Planning

In October 2024, the BNetzA approved the hydrogen core network, which is being built by the hydrogen transmission network operators and other DSOs. The approved core network measures must be reviewed as part of the Network Development Plan. The Germany-wide hydrogen transmission network is currently under construction. The first pipeline sections were already completed in 2025.

4.2 initial network for modelling

4.2.1 Methane

According to the approved Scenario Framework 2025, the starter network used for methane network modelling comprises:

- the existing gas transmission network,
- measures completed and commissioned since the previous network development plans,
- measures currently under construction, and
- further measures selected from the Gas Network Development Plan 2022–2032 as of 1 September 2025 based on the following criteria:
  - The Final Investment Decision (FID) by the gas transmission system operators has been made and
  - the project permits required under public law have been obtained.

For network simulation purposes, the measures included in the starter network are treated in the same way as existing pipelines and facilities. In effect, they have the same status as the existing network.

4.2.2 Hydrogen

Pursuant to Section 28q (8) EnWG, measures in the Network Development Plan scheduled for commissioning before 31 December 2027 in accordance with the core network approval and already underway by 31 December 2025 are not included in the review. These measures define the starter network for hydrogen network modelling. Similarly, the starter network criteria for methane infrastructure are also applied in the hydrogen sector.

4.2.3 Measures put into operation by 1 September 2025

The following measures which have been taken either from the Gas Network Development Plan 2022–2032 (Table 8) or from the core network approval (Table 9), were commissioned by 1 September 2025 and are therefore no longer included in the Gas and Hydrogen Network Development Plan 2025 or in the Gas NDP database.

Table 8: Methane projects commissioned by 1 September 2025

No.	ID number	Network expansion measure	Gas TSO
1	067-02a	Voigtslach-Paffrath pipeline	OGE/Thyssengas
2	067-03b	Paffrath M&R station and connecting pipeline	OGE/Thyssengas
3	112-03	Heilbronn connection	terranets bw
4	116-02	Wiernsheim M&R station (Heilbronn area)	terranets bw
5	119-03	Achim M&R station	GUD
6	204-02a	ZEELINK 1	OGE/Thyssengas

No.	ID number	Network expansion measure	Gas TSO
7	204-02b	ZEELINK 1 M&R station in Glehn and connecting pipeline	OGE/Thyssengas
8	204-02c	ZEELINK 1 M&R station in St. Hubert and connecting pipeline	OGE/Thyssengas
9	204-03d	ZEELINK 1 M&R station in Stolberg and connecting pipeline	OGE/Thyssengas
10	205-02a	ZEELINK 2	OGE/Thyssengas
11	205-03b	ZEELINK 2 M&R station in Legden and connecting pipeline	OGE/Thyssengas
12	206-02	Mittelbrunn M&R station	NaTran_D/OGE
13	300-02	Integration of the Folmhusen compressor station into the H-gas system	GUD
14	302-01	Datteln-Herne pipeline	Thyssengas
15	305-02	TENP reversal	Fluxys/OGE
16	307-01	Mittelbrunn M&R station	NaTran_D/OGE
17	312-02	MEGAL compressor station Rimpar	NaTran_D/OGE
18	320-01	Conversion of the Bergheim 1 network area to H-gas	Thyssengas
19	331-01	Scheidt M&R station	OGE
20	333-02	Asbeck M&R station and connecting pipeline	OGE
21	335-02a	Kempershöhe M&R station and connecting pipeline	OGE
22	335-02b	Wipperfürth-Niederschelden pipelines	OGE
23	337-02	Porz M&R station	OGE
24	338-02	Paffrath M&R station	OGE
25	402-02b	Wertingen 2 M&R station	bayernets
26	402-02c	Kötz M&R station	bayernets
27	416-02	Legden compressor station	OGE/Thyssengas
28	418-02	Expansion of Scharenstetten compressor station	terranets bw
29	422-01	Elten compressor station	OGE/Thyssengas
30	431-02	Emstek M&R station	GTG Nord
31	435-03	Altena M&R station and connecting pipeline	OGE
32	439-01	Pattscheid M&R station and connecting pipeline	OGE
33	440-02	Erftstadt-Euskirchen pipeline	OGE
34	441-02	Vinnhorst valve station and connecting pipeline	OGE

No.	ID number	Network expansion measure	Gas TSO
35	442-02	Ahlten M&R station and connecting pipeline	OGE
36	443-02	Drohne M&R station and connecting pipeline	OGE
37	444-01a	Werne/Stockum M&R station and connecting pipeline	OGE
38	446-01	Wipperfürth-Niederschelden conversion	Thyssengas
39	448-01	Euskirchen M&R station and connecting pipeline	OGE
40	449-02	Extension of Heilbronn connection (SEL 1)	terranets bw
41	501-02a	Walle-Wolfsburg pipeline	GUD
42	501-03e	Expansion of the Unterlüß M&R station	GUD
43	502-03b	Hetlingen M&R station	GUD
44	502-03a	Brunsbüttel-Hetlingen pipeline	GUD
45	503-03b	Expansion of Embsen compressor station	GUD
46	504-01a	EPT-Rysum – Rysum-Folmhusen pipeline connection	GUD/Thyssengas
47	504-02b	Expansion of Folmhusen M&R station	GUD
48	504-02c	Emden M&R station	GUD
49	507-01a	EUGAL gas transmission pipeline	Fluxys D/GASCADE/GUD/ONTRAS
50	507-01h	Börnicke M&R station (DÜG)	ONTRAS
51	507-01l	Reversal of Holtum compressor station	GUD/OGE
52	507-02d	Radeland II compressor station	Fluxys D/GASCADE/GUD/ONTRAS
53	508-01	Expansion of Leonberg-West M&R station	terranets bw
54	524-01	Steinfeld-Düpe M&R station modifications	GTG Nord
55	525-02	Meerbusch Osterrath M&R station and connecting pipeline	OGE
56	526-01	Hamm-Bergkamen pipeline	OGE
57	528-01	Merschhoven-Daberg pipeline	OGE
58	529-01	Elten-St. Hubert valve stations	Thyssengas/OGE
59	530-01	Cologne-Dormagen conversion	Thyssengas
60	552-01	Mittelbrunn-Schwanheim pipeline	Fluxys/OGE
61	554-01	Hügelheim-Tannenkirch pipeline	Fluxys/OGE
62	555-03	Cross-connections TENP I to TENP II	Fluxys/OGE

No.	ID number	Network expansion measure	Gas TSO
63	601-01	M&R pipeline at Lauchhammer station	ONTRAS
64	602-02	Schwanheim-Au am Rhein pipeline	Fluxys/OGE
65	603-01	Schwarzach-Eckartsweier pipeline	Fluxys/OGE
66	604-01	Tannenkirch-Hüsingen pipeline	Fluxys/OGE
67	625-01	Scharenstetten M&R station	terranets bw
68	645-01	Neuenkirchen-Rheine pipeline	Thyssengas
69	651-01	Neuss Rheinpark M&R station and connecting pipeline	OGE
70	652-01	Engelbostel M&R station and connecting pipeline	OGE
71	654-02	Iserlohn Hennen valve station	OGE
72	657-01	Conversion to H-gas (Rehden-Bassum area)	Nowega
73	659-01	Conversion to H-gas (Kolshorn-Ahlten-Empelde storage facility)	Nowega
74	824-01	Meschede-Bockum M&R station expansion	Thyssengas
75	825-01	Arnsberg-Niedereimer M&R station expansion	Thyssengas
76	826-01	Düren loop line	Thyssengas
77	827-01	Nittingen M&R station expansion	bayernets
78	851-01	WAL Part 1	OGE
79	853-01	Wilhelmshaven M&R station and connecting pipeline	OGE
80	855-01	Friedeburg-Horsten 1 M&R station and connecting pipeline	OGE
81	862-01	Sande Nüttermoor/ Jemgum pipeline	GTG Nord
82	863-01	Westerstede M&R station	GTG Nord
83	864-01	Sande M&R station	GTG Nord
84	865-01	Leer M&R station and connecting pipeline	GTG Nord
85	872-01	Connecting pipeline for LNG Stade (accelerated limited capacity for FSRU)	GUD
86	873-01	M&R station at the LNG Stade plant (accelerated limited capacity for FSRU)	GUD
87	874-01	Partial use of DSO line Brunsbüttel-Klein Offenseth (accelerated limited capacity for FSRU)	GUD
88	882-02	Conversion of EST Lubmin 2	Fluxys D/GASCADE/GUD/NEL Gastransport/ ONTRAS

No.	ID number	Network expansion measure	Gas TSO
89	883-01	Expansion of Radeland 2	Fluxys D/GASCADE/GUD/ONTRAS
90	901-01a	Wilhelmshaven 2, Voslapper Groden M&R station and connecting pipeline	OGE
91	902-01	WAL Part 2	OGE
92	904-01	Automation system reversal Medelsheim-Mittelbrunn	OGE/NaTran_D
93	913-01	EUGAL-JAGAL-OPAL connection	Fluxys D/GASCADE/GUD/Lubmin-Brandov Gastransport/ONTRAS/OPAL gas transport
94	914-01	OPAL-STEGAL connection	GASCADE/Lubmin-Brandov Gastransport/ OPAL Gastransport
95	915-02	Connection pipeline to industrial port in Lubmin	Fluxys D/GUD/Lubmin-Brandov Gastransport/ NEL Gastransport/OPAL gas transport
96	916-02	BEG connection pipeline	Fluxys D/GASCADE/GUD/ONTRAS
97	921-01	Flow reversal project at Quarnstedt compressor station	GUD
98	945-01	Connection to the Bremen-West pipeline infrastructure	GUD
99	1012-01	Transfer of BGA Nonnendorf customer connection to JAGAL to NBB at Jüterbog	GASCADE

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 9: Hydrogen projects commissioned by 1 September 2025

No.	ID number	Network expansion measure	Hydrogen network operator
1	KLN033-01a	Hanekenfähr-Schepsdorf 1 incl. M&R stations	Nowega
2	KLN101-01	Leuna Süd-Leuna Süd 1 incl. M&R stations	ONTRAS
3	KLU053-01	Schepsdorf-Frenswegen incl. M&R stations	Nowega
4	KLU054-01	Frenswegen-Bad Bentheim incl. M&R stations	Nowega
5	KLU107-01	Bad Lauchstädt-Milzau incl. M&R stations	ONTRAS
6	KLU109-01	Milzau-Leuna incl. M&R stations	ONTRAS
7	KLU111-01a	Leuna-Leuna Süd incl. M&R stations	ONTRAS

Source: Coordination Office for Gas and Hydrogen Network Development Planning

4.2.4 Projects under construction

The following projects are under construction as of 1 September 2025.

Table 10: Methane projects under construction (as of 1 September 2025)

No	ID number	Network expansion measure	Gas TSO
1	402-02a	AUGUSTA (Wertingen-Kötz pipeline)	bayernets
2	417-02	Mörsch compressor station (Northern Black Forest line)	terranets bw
3	437-02	Heiden-Borken M&R station and connecting pipeline	OGE
4	444-02b	Werne M&R station and connecting pipeline	OGE
5	451-02	Expansion of M&R station in Au am Rhein	terranets bw
6	527-01	Stockum-Bockum Hövel pipeline	OGE
7	612-02	Löchgau-Altbach pipeline (SEL 2)	terranets bw
8	614-02	Heidelberg-Heilbronn pipeline (SEL 3)	terranets bw
9	620-02	Kirchheim unter Teck M&R station	terranets bw
10	621-02	Hittistetten M&R station	terranets bw/bayernets
11	629-02	Reckrod compressor station	GASCADE
12	815-02	Lauchhammer 2 M&R station	ONTRAS
13	822-01	Drohne 2M&R station and connecting pipeline	OGE
14	856-01	Etzel-Wardenburg pipeline	OGE
15	857-01	Wardenburg M&R station and connecting pipeline	OGE
16	858-01	Wardenburg-Drohne pipeline	OGE
17	875-01	Expansion of Rehden compressor station	GASCADE
18	943-02	Lengthal pipeline connection	bayernets
19	947-02	Rerouting work on the Leuna-Nempitz pipeline system	ONTRAS
20	964-01	Lauchhammer III M&R station	ONTRAS
21	1040-01a	System separations on the Emsbüren-Bad Bentheim pipeline system	ONTRAS
22	1040-01g	System separations on the Bad Bentheim-Legden pipeline system	OGE
23	1040-01h	System separations on the Legden-Dorsten pipeline system	OGE/Nowega
24	1051-01	Transfer on the Bobbau-Großkugel pipeline system	OGE/Nowega
25	1102-01	Conversion to H gas (conversion area: in the production area/upstream)	GUD

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 11: Hydrogen projects under construction (as of 1 September 2025)

No	Core network ID	NDP ID	Network expansion measure	HTNO/DSO-HCNO
1	AND030-01	H2-3030-01	Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
2	AND031-01	H2-3031-01	Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
3	AND032-01	H2-3032-01	Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
4	AND033-01	H2-3033-01	Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
5	AND034-01	H2-3034-01	Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
6	AND035-01	H2-3035-01	Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
7	AND036-01	H2-3036-01	Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
8	AND040-01	H2-3040-01	Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
9	KLU003-01	H2-003-01a	Haiming-Lengthal pipeline incl. M&R stations	bayernets
10	KLU004-01	H2-004-01	Lengthal-Burgkirchen pipeline incl. M&R stations	bayernets
11	KLU013-01	H2-013-02	HYOS (formerly OPAL) (Lubmin-Uckermark) incl. M&R stations	GASCADE/LBTG
12	KLU014-01	H2-014-01	HYOS (formerly OPAL) (Uckermark-Radeland) incl. M&R stations	GASCADE/LBTG
13	KLU016-01	H2-016-01	HYRAB (Radeland-Bobbau) incl. M&R stations	GASCADE
14	KLU031-01	H2-031-01	Folmhusen-Nüttermoor pipeline incl. M&R station	GUD
15	KLU032-01	H2-032-01	Folmhusen-Achim pipeline incl. M&R station	GUD
16	KLU033-01	H2-033-01	Ganderkesee-Bremen pipeline incl. M&R station	GUD
17	KLU038-01	H2-038-01	Achim-Heidenau pipeline incl. M&R station	GUD
18	KLU043-01	H2-043-01	Heidenau-Eckel pipeline incl. M&R station	GUD
19	KLU044-01	H2-044-01	Eckel-Leversen pipeline incl. M&R station	GUD
20	KLU051-01	H2-051-01	Lingen-Lingen Nord 1 pipeline incl. M&R stations	Nowega
21	KLU052-01	H2-052-01	Schepsdorf-Lingen pipeline incl. M&R stations	Nowega

No	Core network ID	NDP ID	Network expansion measure	HTNO/DSO-HCNO
22	KLU054-01	H2-054-01	Bad Bentheim M&R station	Nowega
23	KLU066-01	H2-066-01	GetH2 Emsbüren-Bad Bentheim pipeline incl. M&R stations	OGE
24	KLU087-01	H2-087-01	GetH2 Bad Bentheim-Ledgen pipeline incl. M&R stations	OGE/Nowega
25	KLU088-01	H2-088-01	GetH2 Legden-Dorsten pipeline incl. M&R stations	OGE/Nowega
26	KLU097-01b	H2-097-01b	Plaußig-Lüptitz pipeline incl. M&R stations	ONTRAS
27	KLU101-01	H2-101-01	Wefensleben-Wedringen pipeline incl. M&R stations	ONTRAS
28	KLU103-01	H2-103-01	Wedringen 1-Glöthe pipeline incl. M&R stations	ONTRAS
29	KLU129-01	H2-129-01a	GETH2 Vlieghuis-Kalle pipeline incl. M&R stations	Thyssengas H2
30	KLU130-01	H2-130-01	GETH2 Kalle-Ochtrup pipeline incl. M&R stations	Thyssengas H2
31	KLN016-01	H2-1016-01	Elsfleth-Ranzenbüttel pipeline incl. M&R stations	GTG Nord
32	KLN048-01	H2-1048-01	GetH2 Heek-Epe pipeline incl. M&R stations	OGE/Nowega
33	KLN050-01	H2-1050-01a	GetH2 Dorsten-Hamborn pipeline incl. M&R stations	OGE/Thyssengas H2
34	KLN105-01	H2-1105-01	HYRUL (Rubenow-Lubmin) incl. M&R stations	GASCADE

Source: Coordination Office for Gas and Hydrogen Network Development Planning

4.2.5 Further initial network measures of the Gas and Hydrogen Network Development Plan 2025

The following measures fulfil the aforementioned criteria for further projects to be included in the starter network.

Table 12: Further methane initial network measures (as of 1 September 2025)

No.	ID number	Network expansion measure	Gas TSO
1	436-02a	Marbeck-Heiden pipeline	OGE
2	531-01a	Appeldorn M&R station	Thyssengas
3	531-01b	Xanten valve station	Thyssengas
4	622-01	Eichstegen M&R station	terranets bw
5	767-03	Elbe Süd-Achim pipeline	GUD
6	802-01	Lauchhammer valve station	GASCADE/GUD/ONTRAS/Fluxys D
7	839-02	Sonsbeck M&R station	Thyssengas/OGE

No.	ID number	Network expansion measure	Gas TSO
8	880-02	Construction of Wittenburg compressor station	NEL Gastransport/GUD/Fluxys D
9	919-02	Achim West compressor station	GUD
10	920-02	Achim centre M&R station	GUD
11	1013-01	Transfer of customer connection on the STEGAL pipeline from Gera to Rückersdorf	GASCADE
12	1031-01	Achim West compressor station expansion	GUD

Source: Coordination Office for Gas and Hydrogen Network Development Planning

The following table shows the core network measures that, according to the core network approval, are scheduled for commissioning before 31 December 2027. As their execution already began before 31 December 2025, these core network measures will no longer be reviewed in accordance with Section 28q(8) EnWG and are therefore regarded as starter network measures.

Table 13: Further hydrogen initial network measures (as of 1 September 2025)

No.	Core network ID	NDP ID	Network expansion measure	HTNO/HCNO
1	AND037-01	H2–3037-01a	Leversen-Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
2	AND037-01	H2-3037-01b	Leversen M&R station	Hamburger Energienetze GmbH
3	AND038-01	H2–3038-01	Leversen-Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
4	AND039-01	H2–3039-01	Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
5	AND067-01	H2–3067-01	Mühlberg-Röderau pipeline incl. M&R stations	SachsenNetze HS.HD GmbH
6	AND114-01	H2–3114-01	Röderau-Gröditz pipeline incl. M&R stations	SachsenNetze HS.HD GmbH
7	AND115-01	H2–3115-01	Röderau-Riesa pipeline incl. M&R stations	SachsenNetze HS.HD GmbH
8	AND119-01	H2–3119-01	Moorburg compressor station	Hamburger Energienetze GmbH
9	KLN004-01	H2-1004-01	Forchheim-Irsching pipeline incl. M&R stations	bayernets/OGE
10	KLN015-01	H2-1015-01a	Emden-Ost-Nüttermoor pipeline incl. M&R stations	GTG Nord
11	KLN015-01	H2-1015-01b	Leer/ Nüttermoor M&R station	GTG Nord
12	KLN019-01	H2-1019-01a	Rastede-Westerstede pipeline incl. M&R stations	GTG Nord
13	KLN019-01	H2-1019-01b	Westerstede M&R station	GTG Nord

No.	Core network ID	NDP ID	Network expansion measure	HTNO/HCNO
14	KLN023-01	H2-1023-01a	Peine-Hallendorf pipeline incl. M&R stations	GUD
15	KLN023-01	H2-1023-01b	Salzgitter-Hallendorf M&R station	GUD/ONTRAS
16	KLN027-01	H2-1027-01a	Achim-Luttum/Lehringen pipeline incl. M&R stations	GUD
17	KLN027-01	H2-1027-01b	Achim M&R station	GUD/ONTRAS
18	KLN029-01	H2-1029-01	Dykhausen-Ganderkesee pipeline incl. M&R stations	GUD
19	KLN033-01b	H2-1033-01b	Hanekenfähr-Schepsdorf 2 pipeline incl.2 M&R stations	Nowega
20	KLN034-01	H2-1034-01	Lingen-Lingen Nord pipeline incl. M&R stations	Nowega
21	KLN035-01	H2-1035-01	H2ercules Wilhelmshaven-Coastal Pipeline (WKL) incl. M&R stations	OGE/GASCADE
22	KLN036-01	H2-1036-01	H2ercules North Sea-Ruhr-Link (NRL I) pipeline incl. M&R stations	OGE/GASCADE
23	KLN037-01	H2-1037-01a	H2ercules North Sea-Ruhr-Link (NRL III) pipeline incl. M&R stations	OGE
24	KLN037-01	H2-1037-01b	Bunde 1 M&R station incl. connecting pipeline	OGE
25	KLN037-01	H2-1037-01c	Emsbüren 1 M&R station incl. connecting pipeline	OGE
26	KLN049-01	H2-1049-01	GetH2 Dorsten-Marl pipeline incl. M&R stations	OGE/Nowega
27	KLN050-01	H2-1050-01b	Dorsten 1 M&R station and connecting pipeline	OGE/Thyssengas H2
28	KLN066-01	H2-1066-01	Milzau-Milzau 1 pipeline incl. M&R stations	ONTRAS
29	KLN067-01	H2-1067-01	Nempitz-Kulkwitz pipeline incl. M&R stations	ONTRAS
30	KLN085-01	H2-1085-01	Amelsbüren pipeline, northern canal crossing – Amelsbüren southern canal crossing, incl. M&R stations	Thyssengas H2
31	KLN087-01	H2-1087-01	Wallach-Hohfeld pipeline incl. M&R stations	Thyssengas H2
32	KLN088-01	H2-1088-01	Möllen-Averbruch pipeline incl. M&R stations	Thyssengas H2
33	KLN099-01	H2-1099-01a	Emsbüren-Dorsten pipeline incl. M&R stations	Thyssengas H2/OGE

No.	Core network ID	NDP ID	Network expansion measure	HTNO/HCNO
34	KLN099-01	H2-1099-01b	Emsbüren 2 M&R station and connecting pipeline	OGE/Thyssengas H2
35	KLU001-01	H2-001-01a	Forchheim-Münchsmünster pipeline incl. M&R stations	bayernets
36	KLU002-01	H2-002-01	Münchsmünster-Neustadt a. d. Donau pipeline incl. M&R stations	bayernets
37	KLU009-01	H2-009-01a	Irsching-Kösching pipeline incl. M&R stations	bayernets
38	KLU009-01	H2-009-01b	Irsching-Menning M&R station	bayernets
39	KLU012-01	H2-012-01a	Zöllnitz-Bad Lauchstädt pipeline incl. M&R stations	Ferngas
40	KLU012-01	H2-012-01b	Bad Lauchstädt M&R station	Ferngas
41	KLU025-01a	H2-025-01a	Ranzenbüttel-Sandkrug pipeline incl. M&R stations	GTG Nord
42	KLU025-01b	H2-025-01b	Huntorf-Elsfleth 1 pipeline incl. M&R stations	GTG Nord
43	KLU025-01a	H2-025-01c	Sandkrug M&R station	GTG Nord
44	KLU027-01	H2-027-01a	Sande-Jemgum pipeline incl. M&R stations	GTG Nord
45	KLU027-01	H2-027-01b	Sande M&R station	GTG Nord
46	KLU029-01	H2-029-02	Huntorf-Rastede pipeline incl. M&R stations	GTG Nord
47	KLU030-01	H2-030-01a	Oude Statenzijl-Folmhusen pipeline incl. M&R stations	GUD
48	KLU030-01	H2-030-01b	IP Bunde/Oude M&R station	GUD
49	KLU046-01	H2-046-01b	Kolshorn-Sophiental pipeline incl. M&R stations	GUD
50	KLU092-01	H2-092-01	Ketzin-Buchholz pipeline incl. M&R stations	ONTRAS
51	KLU093-01	H2-093-01	Buchholz-Apollensdorf pipeline incl. M&R stations	ONTRAS
52	KLU094-01	H2-094-01a	Bobbau-Großkugel pipeline incl. M&R stations	ONTRAS
53	KLU094-01	H2-094-01b	Bobbau 1 M&R station	ONTRAS
54	KLU095-01	H2-095-01	Apollensdorf-Bobbau pipeline incl. M&R stations	ONTRAS
55	KLU096--01	H2-096-01	Großkugel-Schkeuditz pipeline incl. M&R stations	ONTRAS
56	KLU097-01a	H2-097-01a	Pipeline Schkeuditz-Plaußig incl. M&R stations	ONTRAS

No.	Core network ID	NDP ID	Network expansion measure	HTNO/HCNO
57	KLU098-01	H2-098-01	Lüptitz-Cavertitz pipeline incl. M&R stations	ONTRAS
58	KLU099-01	H2-099-01	Hennickendorf-Vogelsdorf pipeline incl. M&R stations	ONTRAS
59	KLU100-01	H2-100-01	Vogelsdorf-Blumberg pipeline incl. M&R stations	ONTRAS
60	KLU102-01	H2-102-01	Wedringen-Wedringen pipeline incl. M&R stations	ONTRAS
61	KLU104-01	H2-104-01	Glöthe-Bernburg pipeline incl. M&R stations	ONTRAS
62	KLU105-01	H2-105-01	Bernburg-Preußlitz pipeline incl. M&R stations	ONTRAS
63	KLU106-01	H2-106-01	Bad Lauchstädt-Halle pipeline incl. M&R stations	ONTRAS
64	KLU108-01	H2-108-01	Milzau 1-Großkugel pipeline incl. M&R stations	ONTRAS
65	KLU110-01	H2-110-01	Leuna-Böhlen pipeline incl. M&R stations	ONTRAS
66	KLU111-01b	H2-111-01b	Leuna Süd-Nempitz pipeline incl. M&R stations	ONTRAS
67	KLU112-01	H2-112-01	Cavertitz-Mühlberg pipeline incl. M&R stations	ONTRAS
68	KLU123-01	H2-123-01a	Coesfeld-Amelsbüren pipeline incl. M&R stations	Thyssengas H2
69	KLU124-01	H2-124-01	Amelsbüren-Rinkerode pipeline incl. M&R stations	Thyssengas H2
70	KLU125-01	H2-125-01	Hohfeld-Ossenberg pipeline incl. M&R stations	Thyssengas H2
71	KLU126-01	H2-126-01	Wallach-Möllen pipeline incl. M&R stations	Thyssengas H2
72	KLU131-01	H2-131-01	Wallach-Xanten pipeline incl. M&R stations	Thyssengas H2
73	KLU137-01	H2-137-01	Apollensdorf-Wittenberg pipeline incl. M&R stations	ONTRAS

Source: Coordination Office for Gas and Hydrogen Network Development Planning

4.3 Status of measures in the Gas Network Development Plan 2022–2032 and the hydrogen core network

According to Section 15c (2) of the Energy Industry Act (EnWG), the current Gas and Hydrogen Network Development Plan must contain *"information on the implementation status of the most recently published Gas and Hydrogen Network Development Plan and, in the event of any delay, the reasons for the delay. The first Network Development Plan* [Gas and Hydrogen] *must also contain information on the implementation status of the hydrogen core network."* This requirement is met in Annex 1.

In addition, various measures have been omitted in the course of modelling the Gas and Hydrogen Network Development Plan 2025; these are presented in in Annex 2, complete with a justification for their omission.

Change of project names

The gas TSOs and hydrogen transmission system operators would like to point out that the names of the measures listed in the Gas and Hydrogen Network Development Plan may be provisional at this stage and may change in the course of more detailed investigations, technical elaborations and approval processes as the project progresses. This is because the names are selected at an early planning stage.

The reasons for possible changes are, in particular:

- **Technical requirements:** The final route and connection are only determined as planning progresses.
- **Approval law aspects:** Regional planning reviews, opposition or new circumstances may necessitate adjustments.
- **Standardisation:** The final names are selected according to company-specific technical standards and are only determined in subsequent project phases.

5 Security of Supply Review for Methane for 2030

5.1 Introduction and approach

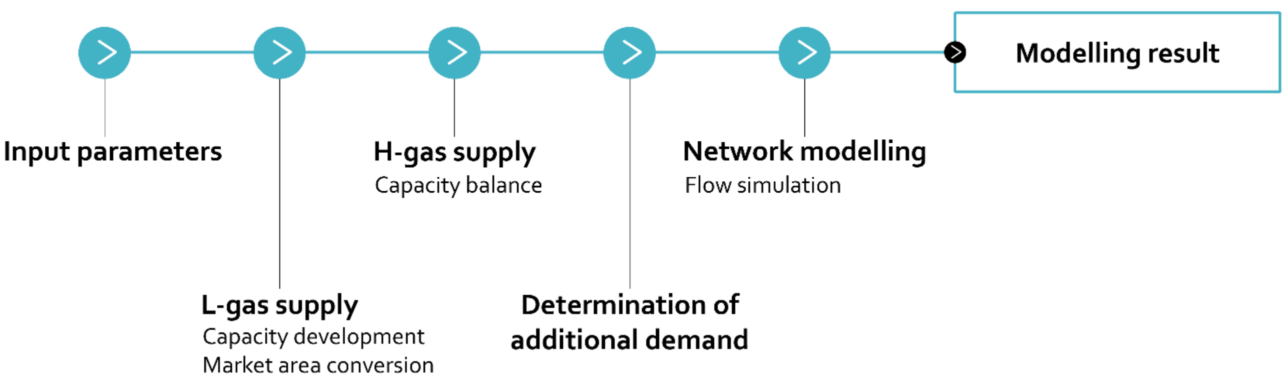
The comparison between trends towards declining methane demand in the long-term scenarios, some of which provide the basis for scenarios 1 to 3 approved by the BNetzA, and the increasing demand forecasts for methane underline the current level of uncertainty regarding future demand. In the draft Scenario Framework 2025, the gas transmission system operators have therefore proposed modelling an additional scenario for the year 2030 that goes beyond the legal mandate so as to be able to incorporate a medium-term perspective in line with their primary mandate – ensuring security of supply – into the network development planning process, in addition to considering long-term developments in methane in 2037 and 2045.

The BNetzA shares the gas transmission system operators' view regarding the importance of such a medium-term perspective and has subsequently confirmed the security of supply review for 2030 in the approval of the Scenario Framework as scenario 4.

As already explained in chapter 3.1.1, the data basis for the security of supply review is the feedback and demand estimates received from market participants, which were used unchanged by the gas transmission system operators for their modelling. The data basis consisted of LTFs for methane from DSOs from the first quarter of 2024, demand reports from industrial customers and from power plant customers, capacity reservations and capacity expansion claims in accordance with Sections 38 and 39 of the GasNZV, and the additional H-gas demand resulting from the market area conversion.

This established market information-based network modelling approach is presented in Figure 14. It starts with determination of the relevant input variables for network modelling, which is followed by an analysis of the L-gas supply situation to determine the conversion areas and the development of the L-gas capacity. The next step is then to establish the H-gas capacity balance on this basis and determine any additional H-gas capacity demand. This is followed by an analysis to see if the required additional H-gas capacity demand – if any – can be met by further entry capacities not yet taken into account for the capacity balance. The final step is the network modelling work by the gas transmission system operators. The final results obtained after several iteration steps provide the basis for determining the network expansion requirement.

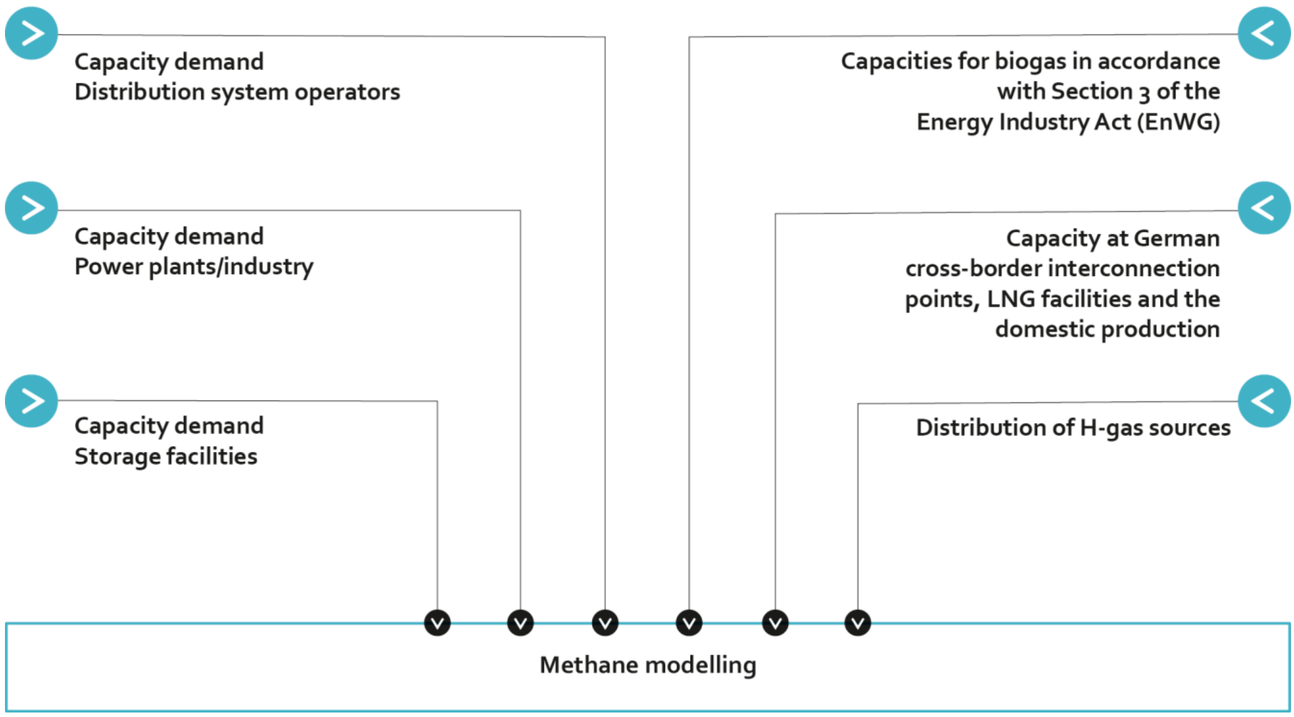
Figure 14: Basic approach to methane modelling 2030



Source: Coordination Office for Gas and Hydrogen Network Development Planning

The input variables used for network modelling are basic data obtained from various data sources, which are adjusted or updated as necessary.

Figure 15: Input variables for methane modelling 2030



Source: Coordination Office for Gas and Hydrogen Network Development Planning

All input capacities used for network modelling can be found in the Gas NDP database in the "2025 – NDP 2nd draft" cycle.

5.2 Input variables

The modelling looks at whether sufficient H-gas capacity is available to meet the expected development in gas demand. This involves comparing the entry capacities available in the peak load case, i.e. firm capacities plus any interruptible capacities, with the expected exit demand.

5.2.1 Exit capacity

5.2.1.1 Power plants

According to the requirements specified by the BNetzA, this scenario is based on all existing and newly planned methane-fired power plants with a total electrical capacity of 58 GW_e as per the BNetzA power plant list. The power generating units are assigned to network connection points in the gas transmission system, which gives a total electrical capacity of over 40 GW_e (78 GW_{th}) to be taken into account for power plants supplied via the gas transmission system. This includes the electrical capacity of existing power plants as well as capacity reservations and capacity expansion claims in accordance with Sections 38 and 39 of the GasNZV, leaving 16 GW_e for power plants supplied via distribution systems. The corresponding methane capacity demand is already included in the DSOs' LTFs.

For power plants supplied via the gas transmission system, both the updated capacities technically available at the network connection points and the connection capacities confirmed as part of the capacity reservations and capacity expansion claims in accordance with Sections 38 and 39 of the GasNZV are used as the gas connection capacity.

5.2.1.2 Industry

As explained in chapter 3.3.1.2, the future methane requirements of the industrial sector were determined as part of the development of the Scenario Framework 2025 through a direct survey of industrial customers connected to the gas transmission system up to 2035.

The requirements reported by these customers were taken into account in the determination of the relevant capacities to be applied in scenario 4 for the gas transmission system in 2030. For network connection points for which no reports were received, the existing firm capacity was carried forward.

The requirements of new industrial customers were also taken into account, provided they were communicated to the transmission system operators in the course of the Scenario Framework process.

5.2.1.3 Distribution system operators

As described in chapter 3.3.1.3, the LTFs for methane capacity demand in 2025–2035 were reported by the DSOs in 2024. The reported methane capacity demand figures were checked for plausibility in that reported increases in capacity demand were only taken into account if the DSOs provided a comprehensible justification.

In scenario 4, this LTF, checked for plausibility, was used for the year 2030.

5.2.1.4 Cross-border interconnection points

For scenario 4 and the target year 2030, the BNetzA requires the exit capacities at cross-border IPs to be taken into account as 69 GWh/h, which is in line with the planning assumptions of the gas transmission system operators that are based on the capacity reports submitted by the gas transmission system operators to the BNetzA in accordance with the ANIKA specification. As described in chapter 3.3.1.4, no exit capacities are taken into account ,if these cross-border IPs that are used for entries in the peak load case.

5.2.2 Entry capacity

5.2.2.1 Cross-border interconnection points

The estimated entry capacity at cross-border IPs is based on the respective technically available capacities (plus the interruptible capacities that can be used in a peak load situation). In total, 152 GWh/h were specified by the BNetzA for this scenario.

5.2.2.2 Storage

The BNetzA requires gas transmission system operators to take into account minimum entry capacities of 130 GWh/h.

To cover demand for withdrawal capacity, the gas transmission system operators first use the available capacity at LNG terminals and cross-border IPs in their H-gas capacity balance, as it is assumed that these entry capacities will not be affected by any storage filling level restrictions. The storage facilities are then used to meet capacity demand, taking into account local transportation conditions. Firm capacities are applied in accordance with the status reported in the Gas NDP database ("2025 – NDP 2nd draft" cycle). Interruptible capacities are also taken into account.

As of the cut-off date of 1 May 2024, the transmission system operators had not received any capacity reservations or capacity expansion claims in accordance with Sections 38 and 39 of the GasNZV for storage facilities.

5.2.2.3 LNG terminals

For the Gas and Hydrogen Network Development Plan 2025, the transmission system operators have received capacity reservations and capacity expansion claims in accordance with Sections 38 and 39 of the GasNZV for the planned LNG terminals in Wilhelmshaven, Brunsbüttel, Stade, Lubmin, Mukran and Rostock amounting to 79 GWh/h, which are fully included in the modelling.

To meet demand in the peak load case, an additional 4 GWh/h of interruptible capacity has been included at the LNG terminal in Mukran.

5.2.2.4 Domestic production and biomethane

In the German production regions of Elbe-Weser and Weser-Ems, the Imbrock, Groothusen, Leer and, following the market area conversion, Munster gas fields also produce volumes that are fed exclusively into the H-gas network. The BVEG forecast does not provide a breakdown of the individual volumes.

The capacity of these fields has averaged around 320 MW in recent years. This capacity has been extrapolated using the average annual percentage decline in the BVEG forecast and has been taken into account accordingly in the H-gas capacity balance. From GY 2029/2030 onwards, the remaining L-gas production detailed in the production forecast will also be taken into account. The reason for this is that the market area conversion will be almost complete by this point, which means that the remaining German L-gas production will have to be mixed with H-gas.

This gives a total of 3 GWh/h for domestic production.

In 2023, 242 plants fed biomethane into the gas grid, amounting to entries totalling around 10.2 TWh (calorific value) [BNetzA 2024]. The dena 'Einspeiseatalas' also contains information on biomethane processing plants that are either planned or under construction [dena 2025]. It is assumed that these plants will be commissioned and that utilisation of biomethane feed-in plants will improve in the long term. Synthetic methane entries are not included, as the transmission system operators have not reported any demand for this.

An entry capacity of around 1 GWh/h has been assumed for biomethane.

This gives a total production capacity of 4 GWh/h for both, domestic production and biomethane.

5.2.2.5 Additional demand for H-gas

According to the Gas and Hydrogen Network Development Plan 2025, there is no additional demand for H-gas that would require an increase in entry capacities at cross-border IPs.

5.3 Market area conversion and L-gas capacity development until 2030

Part of the German gas market is currently still supplied with L-gas. This L-gas comes exclusively from German and Dutch sources.

Methane production in the Groningen field in the Netherlands has already declined significantly in recent years and only has been used as a reserve from the 2023/2024 winter season onwards [MEACP 2024]. The Groningen field was finally closed in April 2024 [MEK 2023]. L-gas imported into Germany now comes exclusively from conversion plants in the Netherlands.

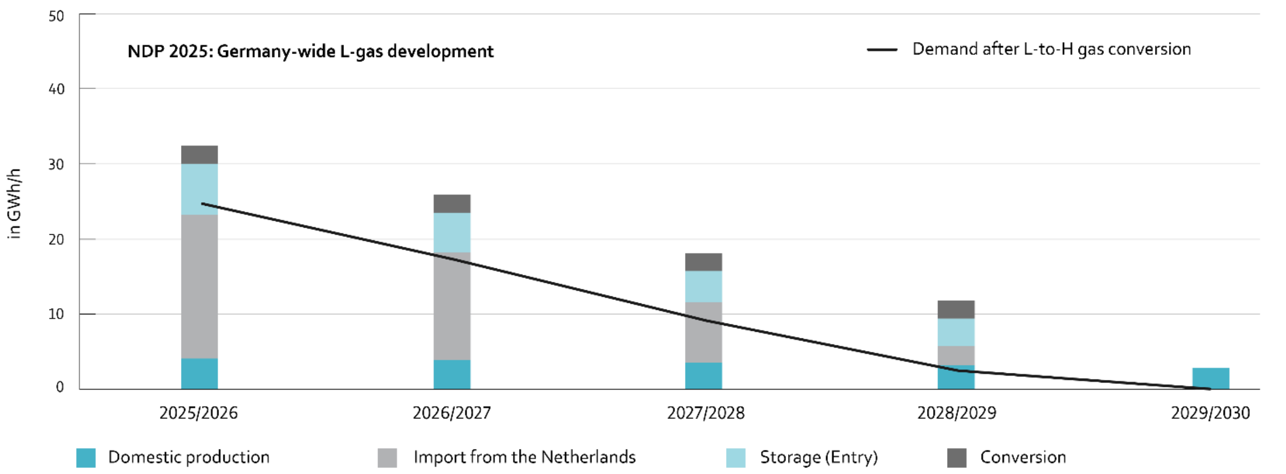
L-gas production in Germany is also declining. To counter these trends in domestic and foreign supplies, the gas transmission system operators are gradually converting the German network areas supplied with L-gas to H-gas. Since the start of the L-to-H-gas conversion in 2015, a total of around 3.6 million gas appliances were converted by the end of 2025.

According to current plans, the conversion from L-gas to H-gas will be completed in GY 2028/2029, meaning that L-gas will no longer play a direct role in the security of supply review for 2030. For reasons of transparency, however, the gas transmission system operators are providing a brief overview of the current status of the conversion plans for the period up to 2030.

5.3.1 L-gas capacity development until 2030

Compared to the results of the 2024 interim report on the market area conversion from L-gas to H-gas [TSO Gas 2024], adjusted input values due to recent developments have led to a reduction in L-gas demand of approximately 1 GWh/h for GY 2024/2025. The following GYs also show slight reductions in L-gas demand. In GY 2029/2030, following the completion of the L-to-H-gas conversion, there will be no direct L-gas demand remaining in the German market area.

Figure 16: Germany-wide L-gas capacity development



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 14: Germany-wide L-gas capacity development

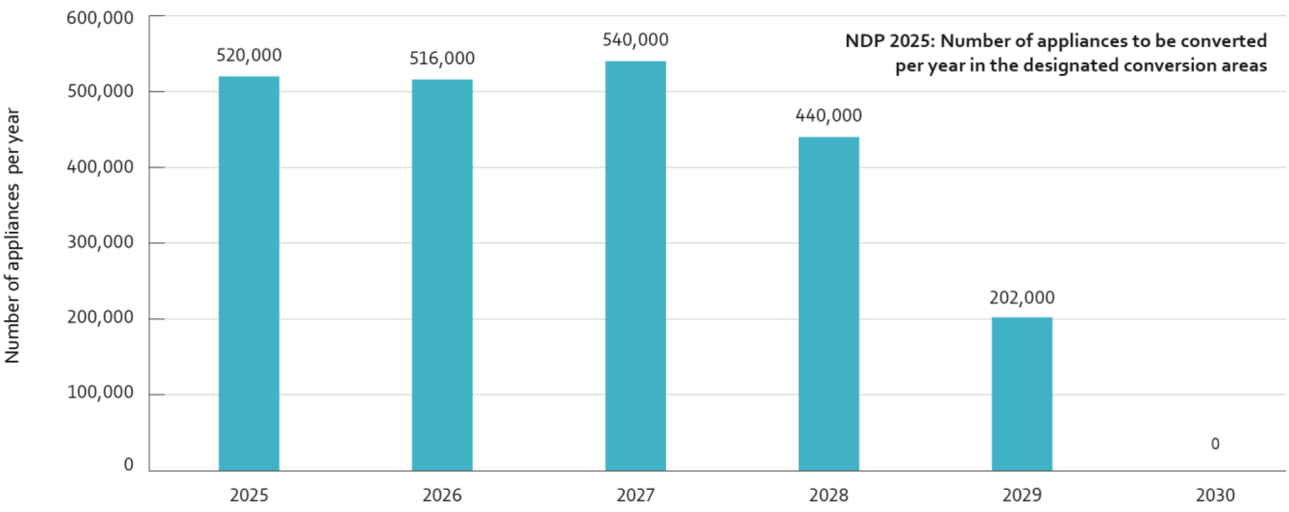
	Domestic production	Imports from NL	Storage entries	Conversion	Total gas available	L-gas demand	L-gas demand w/o L-to-H-gas conversion
	GWh/h						
2025/2026	4.1	19.1	6.8	2.4	32.4	24.7	32.2
2026/2027	3.9	14.3	5.3	2.4	25.9	17.3	33.1
2027/2028	3.5	8.1	4.1	2.4	18.1	9.1	32.9
2028/2029	3.2	2.6	3.6	2.4	11.7	2.5	32.7
2029/2030	2.8	0.0	0.0	0.0	2.8	0.0	31.0

Source: Coordination Office for Gas and Hydrogen Network Development Planning

5.3.1.1 Number of annual gas appliance modifications

The conversion plans include a minimum of 500,000 gas appliances to be adapted annually until 2027. The conversion of some areas brought forward from 2029, as outlined in the 2024 interim report, will lead to a reduction in the number of gas appliances to be converted from 2028 onwards. This will help optimise the use of resources. Plans for the conversion period after 2028 are being further advanced and continuously refined.

Figure 17: Number of gas appliances to be converted per year in the conversion areas designated until 2030



Source: Coordination Office for Gas and Hydrogen Network Development Planning

5.3.1.2 Status of conversion planning

The conversion of network areas to H-gas supply is a very complex exercise and involves considerable costs, both in terms of the necessary changes to the gas appliances for the new gas quality and in terms of ensuring H-gas transport. The areas were selected very carefully and subject to the proviso that security of supply must be maintained across all network levels at all times. This was and continues to be achievable only through close cooperation with the DSOs. The conversion plans for the network areas have been and are being specified in detail together with the DSOs concerned and agreed as binding conversion schedules.

L-to-H-gas conversion planning remains a continuous process that is subject to constant adjustments until contractually agreed. The Gas and Hydrogen Network Development Plan 2025 reflects the planning status as of 31 December 2025. Compared to previous plans, only the conversion date for the "Haanrade" conversion area has changed. According to current plans, this is now scheduled for conversion in 2029.

The concepts for conversion planning have already been largely finalised up to 2029, and the necessary conversion schedules have been agreed with the respective DSOs.

An overview of the L-to-H-gas conversion areas until 2029 is presented in Annex 3.

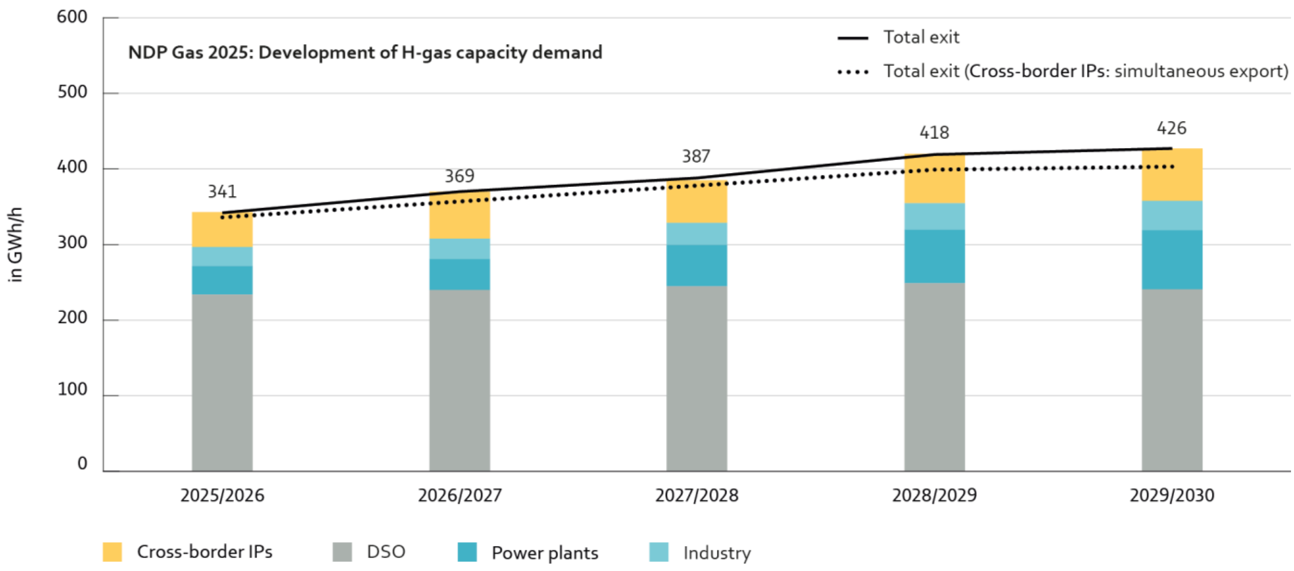
5.4 H-gas capacity balance until 2030

The H-gas capacity balance 2030 examines whether sufficient H-gas capacity is available to meet the expected development in gas demand. It compares the entry capacities available in the peak load case, consisting of firm capacities plus any interruptible capacities, with the expected exit demands in the peak load case.

The H-gas demand is calculated as the sum of the capacity demand of the exit points (cross-border IPs, DSOs, industrial customers, gas-fired power plants) and the additional H-gas demand resulting from the L--to-H-gas conversion to be completed in 2029. Transmission system operators have received demand forecasts indicating rising methane demand by 2030, particularly for the industrial and power plant sectors.

The resulting demand trends are shown in Figure 18 and Table 15.

Figure 18: Development of H-gas capacity demand in the peak load case until 2030



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 15: Data on the development of H-gas capacity demand in the peak load case until 2030

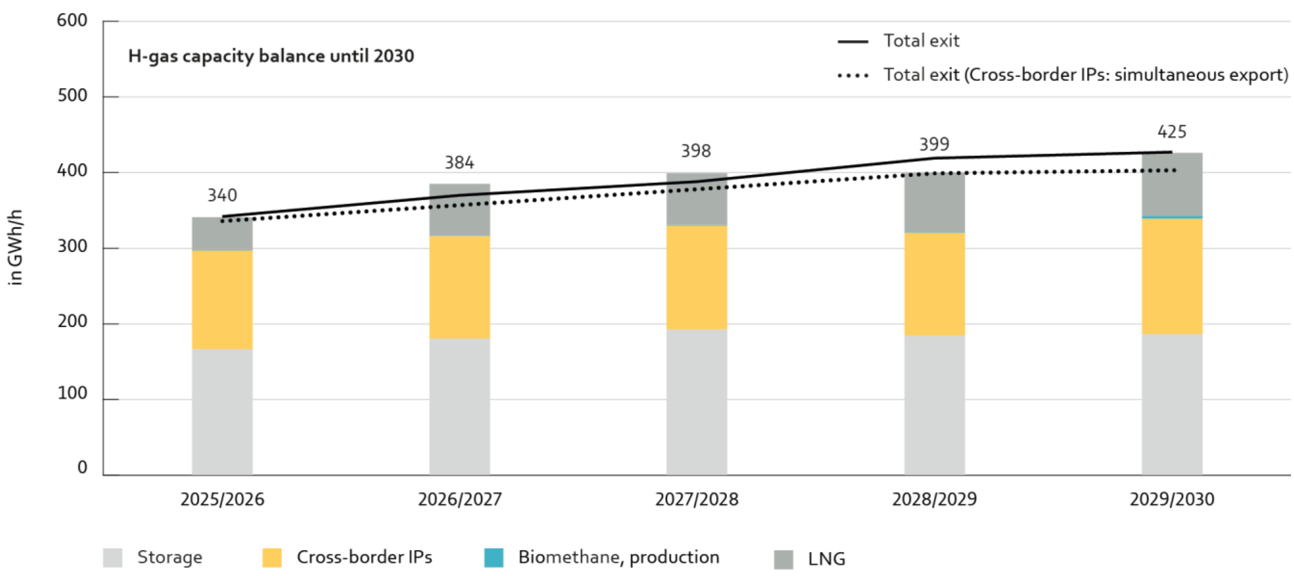
	Cross-border IPs	DSOs	Power plants	Industry	Total exits	Total exits (cross-border IPs: simultaneous export)
	GWh/h					
2025/2026	46	233	38	25	341	335
2026/2027	62	239	41	27	369	352
2027/2028	59	244	55	29	387	370
2028/2029	65	248	71	35	418	398
2029/2030	69	240	78	39	426	402

Source: Coordination Office for Gas and Hydrogen Network Development Planning

In addition to the total exit capacity estimated in the peak load case, the following figure also shows the total exit capacity, taking into account historical utilisation data at cross-border IPs (total exits (cross-border IPs: simultaneous export)). Cross-border IPs are only taken into account on a pro-rata basis in the amount of simultaneous bookings for capacity products, analogous to the methodology explained in chapter 3.3.3.2 for determining the sufficient level of freely allocable entry and exit capacities.

The resulting H-gas balance is shown in Figure 19 and Table 16.

Figure 19: H-gas capacity balance until 2030



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 16: Data on the H-gas capacity balance until 2030

	Storage	Cross-border IPs	LNG	Biomethane production	Total entries	Total exits	Undersupply (+)/ Oversupply (-)
	GWh/h						
2025/2026	166	130	43	1	340	341	1
2026/2027	180	135	68	1	384	369	-15
2027/2028	192	137	68	1	398	387	-11
2028/2029	184	135	79	1	399	418	19
2029/2030	186	152	83	4	425	426	1

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Despite the continuous increase in methane demand until 2029/2030, the exit capacity in the peak load case (total exits) can almost be met in the capacity balance in the modelling year 2029/2030. The key factor in covering this increase in demand was that – as already explained in part in chapter 5.2.2 – additional interruptible entry capacities could be agreed with the relevant neighbouring european gas TSOs. At the Elten/Zevenaar cross-border IPs, the Dutch network operator Gasunie Transport Services B.V. (GTS) confirmed that, following the conversion of the former L-gas points to H-gas in 2028/2029, it can provide additional capacity of 10 GWh/h on an interruptible basis in the peak load case. This will require minor upgrades to the GTS network. At the Mukran LNG terminal, additional interruptible capacity of 4.0 GWh/h can also be provided on the entry side. In total, these compensation measures (additional H-gas demand) will make it possible to almost cover the 2029/2030 capacity balance. The H-gas balance is also covered for GY 2025/2026 to 2027/2028 and is even exceeded.

In GY 2028/2029, there will be a shortage due to the significant increase in methane demand from industry and power plants and the increase in entry capacities that is not yet fully available in this GY, but this does not necessitate any urgent action from the gas transmission system operators' perspective at this point in time.

Against the backdrop of considerable uncertainty regarding future demand trends, particularly in power generation and the industrial sectors, it remains to be seen whether the sharp increase in exit capacity demand from these two sectors of around 49 GWh/h between GY 2026/2027 and 2029/2030 will actually occur or will be delayed to such an extent that the additional entry capacities expected from GY 2029/2030 onwards will be available in time to meet demand.

Furthermore, in a peak load situation, simultaneity effects are to be expected, which can have a compensating effect, also with regard to the supply of Southeastern Europe. The evaluation with regard to the cross-border IP exit capacity used simultaneously for exports also shows such a possible effect.

In addition, other appropriately designed instruments such as LFCs and MBIs are available as capacity-increasing measures in accordance with KARLA Gas 2.0 and ANIKA, and these can contribute to balancing efforts.

5.5 Results of the security of supply variant modelling for 2030

In the modelling of the security of supply variant scenario 4 (2030), the core network conversion measures were assumed to be completed in terms of the topology used, even if the conversion of individual methane pipelines will not take place until after 2030. This assumption combines the remaining methane network with the still high methane demand expected in 2030, resulting in a restrictive network load. In Figure 20, these conversion measures are shown as part of the gas transmission system.

The core network conversion measures for the MEGAL section from Gernsheim to Rothenstadt (KLU084-01, KLU085-01) will still be required in 2030 to meet transportation requirements in the methane network and are therefore included in the 2030 methane modelling, contrary to the basic premise. The related natural gas-reinforcing measures (core network ID 1047-01, 1048-01, 1049-01) have been omitted. The reasons are explained in more detail in chapter 7.5.

Furthermore, modelling has shown that another pipeline can be converted thanks to an additional gas flow route at the Burghausen network node. Therefore, the Überackern-Haiming core network newbuild project (core network ID KLN001-01) can be replaced by the conversion measure.

According to the complementary natural gas network planning for the core network, the Uedemerbruch-Wardt pipeline (core network ID KLU121-01) is also not required for methane transportation in scenario 4 (2030) and can be converted to hydrogen (NDP ID H2-0233).

Based on this premise, the security of supply review for the modelling year 2030 provides the results shown in Table 17. The results show a distinction between measures scheduled for commissioning by the end of 2030 and by the end of 2032 (modelling year of the hydrogen core network 2032) to provide an overview of measures to be commissioned by the end of the modelling year 2030 and to transparently present the results of the review of natural gas-reinforcing core network measures scheduled for commissioning by the end of 2032. The total investments are broken down into different project categories. Network expansion measures from the Gas and Hydrogen Network Development Plan2022 include measures that (i) were already derived from the modelling process in the Network Development Plan 2022, (ii) are not starter network measures (chapter 4.2) and (iii) are reconfirmed by the modelling exercise. Natural gas-reinforcing measures from the Network Development Plan2022 and the core network are also shown if they meet this requirement. New measures are attributable to additional demand from power plants and industry. The hydrogen modelling results of the Gas and Hydrogen Network Development Plan2025 continue to require new natural gas-reinforcing measures.

Table 17: Results of the security of supply review for scenario 4

Scenario 4 results for the year 2030*	**By the end of 2030**	**By the end of 2032**
Technical parameters		
Pipelines [km]	364	364
Compressor capacity [MW]	0	36
Total investment [billion euros]	**2.5**	**2.8**
- of which network expansion measures from NDP 2022	1.0	1.0
- of which natural gas-reinforcing measures from NDP 2022 and core network	1.0	1.3
- of which new network expansion measures to meet demand from power plants and industry demand	0.4	0.4
- of which new natural gas-reinforcing measures	0.1	0.1

* rounded figures

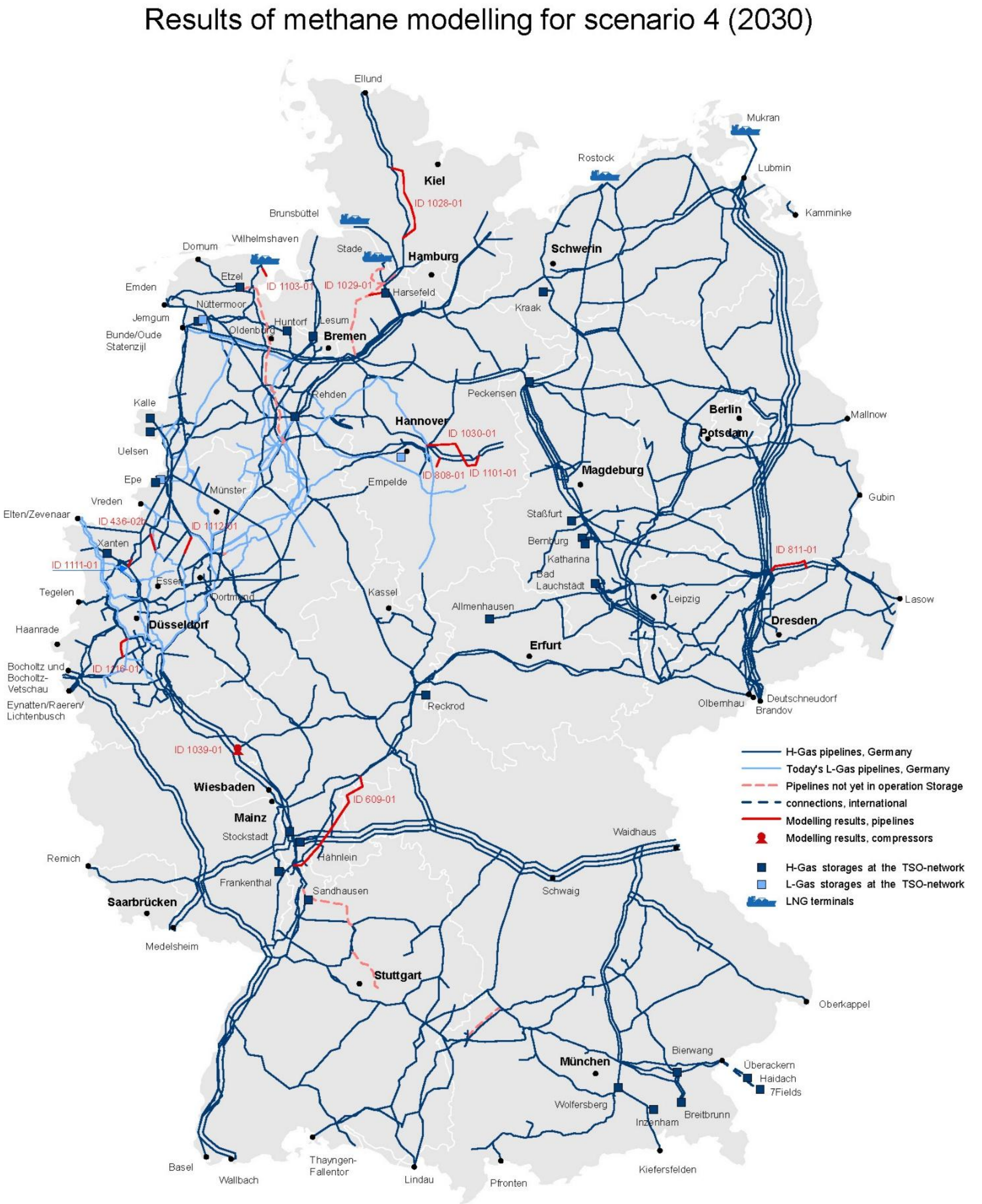
Source: Coordination Office for Gas and Hydrogen Network Development Planning

In the security of supply variant scenario 4 (methane), network expansion measures with an investment volume of around €2.8 billion are identified by the end of 2032.

The modelling results for the required MBIs are shown in chapter 6.5 . MBIs are designed to avoid or reduce additional network expansion requirements as far as possible, as no major new network expansion measures can be delivered by 2030 due to the usual execution periods.

The measures are shown in Figure 20 and reported in the Gas NDP database.

Figure 20: Methane modelling results for scenario 4 (2030)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Scenario-based Modelling for 2037 and 2045

6

6 Scenario-based Modelling for 2037 and 2045

Gas transmission system modelling is based on the regionalisation of exit capacities for each scenario presented in chapter 3 and the relevant entry capacities. The aim is to examine the capability of the network under changed conditions and to identify necessary expansion measures at an early stage. This review is based on the simulation of defined load cases. If the load cases identify any bottlenecks between scheduled entries and exits, the transmission system operators have to define appropriate expansion measures.

Chapter 6.1 presents capacity balances in each scenario for the year 2037. The modelling results for the respective scenarios can be found in chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**. For 2045, the methane results are presented first in chapter 6.3, followed by the hydrogen modelling results in chapter 6.4. Finally, chapter 6.5 sets out the results of the NewCap modelling.

6.1 Capacity balances in methane and hydrogen

Capacity balances examine whether sufficient entry capacities are available in the load case under consideration to meet the expected development of demand. In this chapter, the comparison is made for methane and hydrogen for each scenario. The exit capacity demand in each scenario is presented and compared with the relevant entry capacities.

In methane modelling, peak load analysis is an essential load case in which, due to lower temperatures and low electricity generation from renewable sources, the possible exit capacities for heat and power generation by gas-fired power plants are applied in full for each scenario. The peak load balance for methane is presented in more detail in the following chapter 6.1.1. The calculation of the peak load case is supplemented by the analysis of partial load cases.

Since hydrogen is not used for heat generation in the specified scenarios (or only to a very limited extent), there is a significantly weaker correlation between temperature and hydrogen demand than for methane. However, the impact of partly regional, low-wind weather conditions on the grid is significantly greater due to the interactions with the demand from hydrogen-fired power plants and the simultaneous low production of hydrogen through electrolysis. For this reason, greater consideration is given to different regional distributions of entry and exit loads compared to methane modelling in different load cases (chapter 3.4.5). Consequently, the balance presented for hydrogen is not the balance for a specific load case in chapter 6.1.2, but instead a comparison is made for the requirements defined by the BNetzA for the maximum exit capacities and minimum entry capacities to be applied, which are the input factors for the different load cases.

6.1.1 Methane scenarios 1–3 for 2037

6.1.1.1 Exit capacity demand in peak load case

For classification and better comparability of the peak load situations in scenarios 1–3 in 2037, which are characterised by a significant decline in demand for exit capacity in some cases, the capacity demand of scenario 4 (2030) is additional presented below.

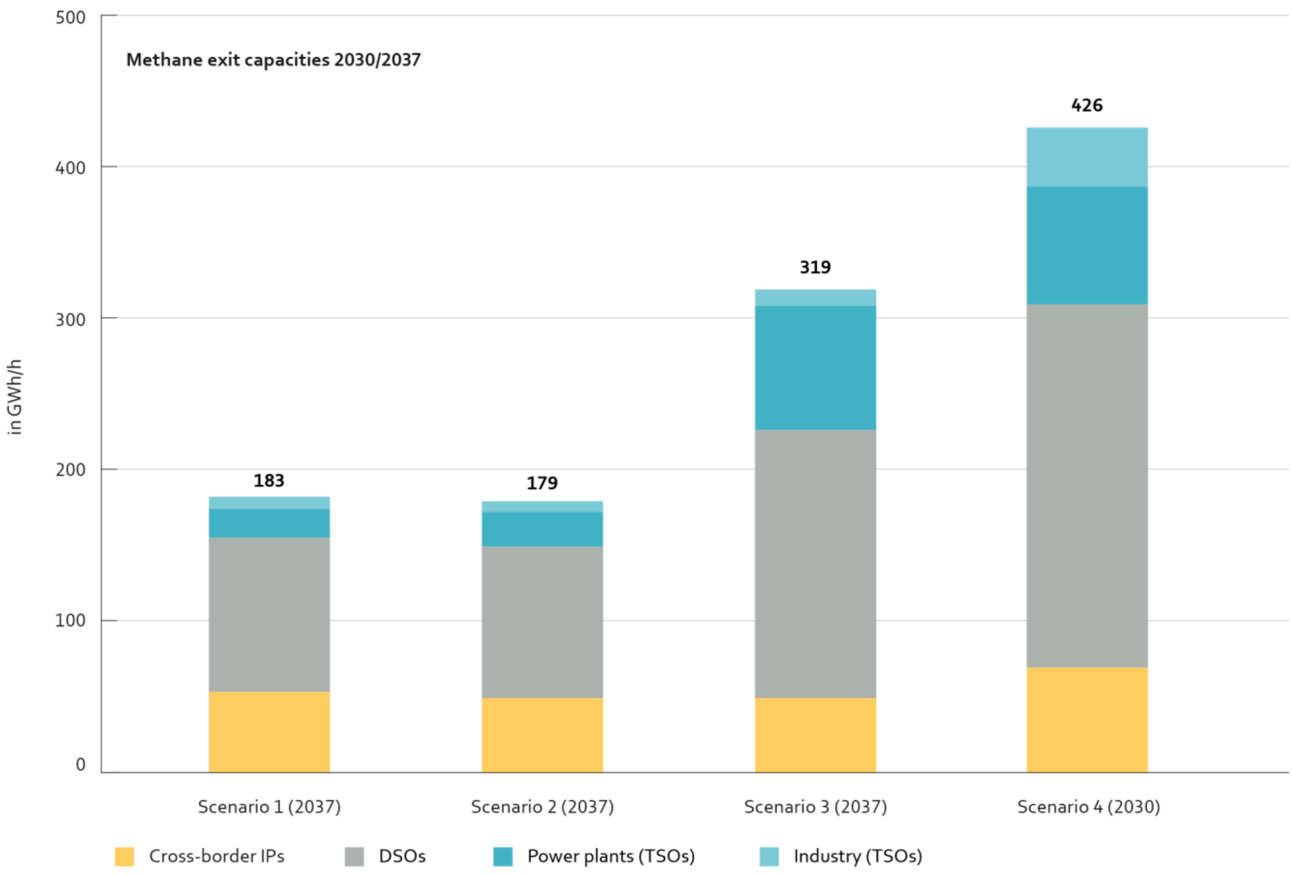
The exit capacity demand for scenarios 1–3 is calculated as the sum of the following individual demands:

- Gas-fired power plants are included in accordance with chapter 3.3.1.1. Capacities are shown on a point-specific basis in the Gas NDP database (Zyklus "2025 – NEP 2. Entwurf"), while capacity requests in accordance with Sections 38 and 39 of the GasNZV are shown separately.
- Industrial customers are included in accordance with chapter 3.3.1.2. Capacities are shown in total for each gas transmission system operator in the Gas NDP database (Zyklus "2025 – NEP 2. Entwurf").

- Distribution system operators are included in accordance with chapter 3.3.1.3. Capacities are published in the Gas NDP database (Zyklus "2025 – NEP 2. Entwurf" cycle) on a point- or zone-specific basis.
- The values assigned to the cross-border IPs correspond to the requirements of the approved Scenario Framework. In addition to the cross-border IP exit capacities relevant to the peak load case, the Gas NDP database (Zyklus "2025 – NEP 2. Entwurf") also shows other non-peak load-relevant exit capacities that have been confirmed as part of the modelling process.

The exit capacity is generally included as FAC in the modelling, except for new power plants, which are represented in the modelling using the fDAC type.

Figure 21: Exit capacity of scenarios 1–3 (2037) and scenario 4 (2030) in the peak load case



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 18: Exit capacity of scenarios 1–3 (2037) and scenario 4 (2030) in the peak load case

	Scenario 1 (2037)	Scenario 2 (2037)	Scenario 3 (2037)	Scenario 4 (2030)
	GWh/h			
Power plants (TSOs)	19	23	82	78
Industry (TSOs)	9	7	11	39
DSOs	102	100	177	240
Cross-border IPs	53	49	49	69
Total	**183**	**179**	**319**	**426**

Source: Coordination Office for Gas and Hydrogen Network Development Planning

In scenarios 1 and 2 (2037), which show a faster transformation of the energy system, capacity demand is reduced by up to 58% compared to scenario 4 (2030) to 183 GWh/h (scenario 1) and 179 GWh/h (scenario 2) respectively. Overall, despite the different focus areas (scenario 1: greater conversion of the energy system to hydrogen supply; scenario 2: greater electrification), a direct comparison of scenarios 1 and 2 reveals only minor differences between the respective total peak capacity demands of the DSO, industry and power plants customer groups and exports via cross-border IPs.

In scenario 3 (2037), which shows a delayed reduction in methane, capacity demand in the peak load case falls by approximately 25% to 319 GWh/h compared to scenario 4 (2030). There is a significant reduction in particular for the DSO and industry customer groups and for exports via cross-border IPs. Due to the capacity requests under Sections 38 and 39 of the GasNZV, which must be included in full in scenario 3, the capacity demand in the power plant sector, at 82 GWh/h, is even higher than the demand in scenario 4 (2030), at 78 GWh/h.

6.1.1.2 Determination of the entry capacity demand for scenarios 1–3 (2037) in the peak load case

To meet the exit capacity demand in the peak load case, imports via cross-border IPs, entries from storage facilities and LNG terminals, and a small amount of production capacity remaining in the market area, including biomethane, are used, with due consideration for minimum entry capacity demand (chapter 3.3.2).

The exit capacities specified in the scenarios, particularly for scenarios 1 and 2, are significantly lower than the values for scenario 4 (2030). Against this backdrop, the gas transmission system operators have also examined whether additional methane pipelines can be converted to hydrogen. Since end user demand in the methane scenarios for 2037 is generally only reduced, conversion to hydrogen is only an option if at least two infrastructures suitable for supply are available in close proximity to the end user, so that despite the conversion of one pipeline, customer demand can still be met via a methane pipeline. However, in many cases, such infrastructure redundancy does not exist. Since pipelines are still needed to supply methane despite lower utilisation rates, the transportation capacity of the remaining methane network confirmed in the model, especially for scenarios 1 and 2, exceeds the requirements of the Scenario Framework with regard to the exit capacity to be applied in the peak load case.

This results in a flexibility confirmed by the model in the approach to specific entry capacities, even between the different point types (cross-border IPs, LNG and storage facilities), especially for scenarios 1 and 2.

Against this backdrop, the exit demand in the peak load case is met by the following entries:

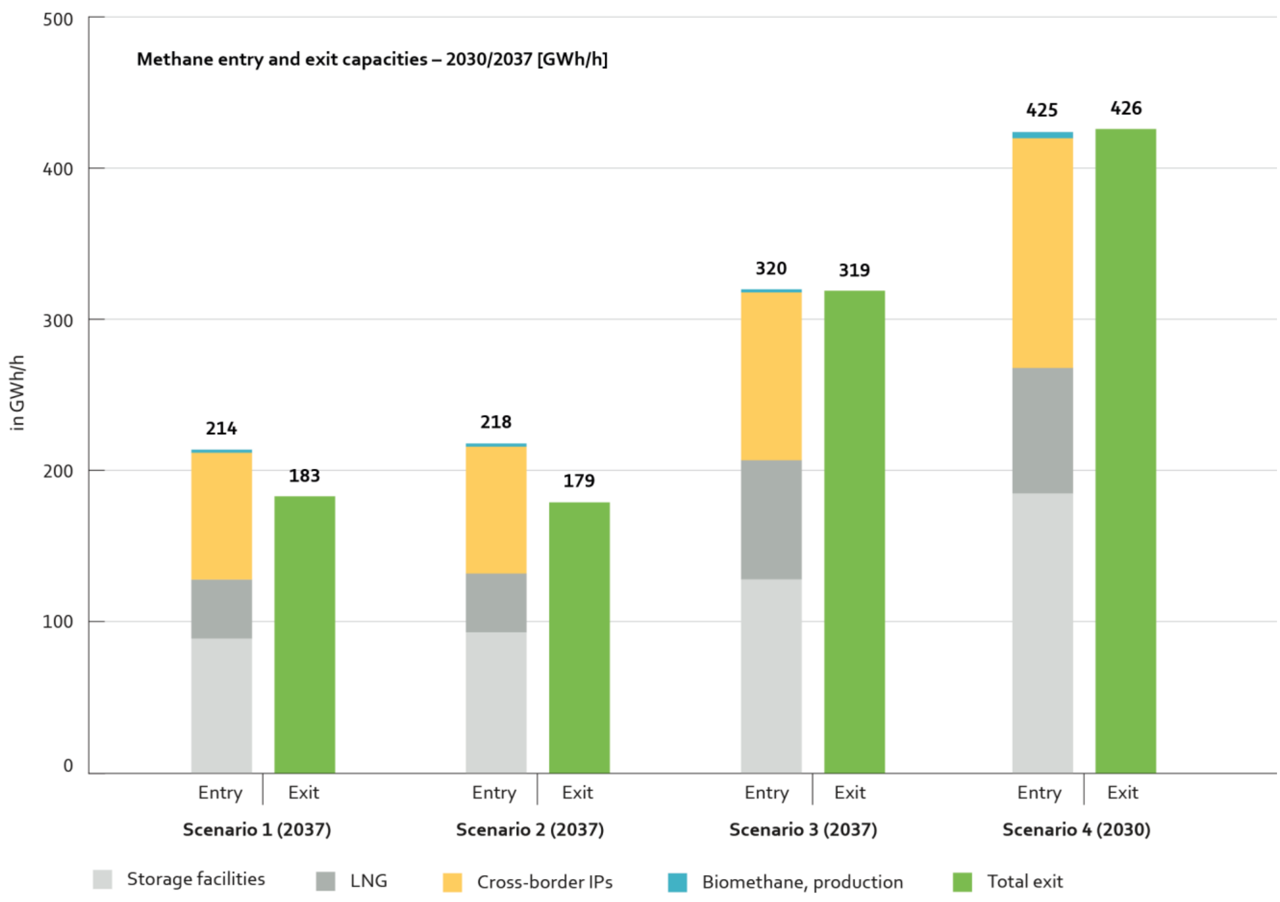
Scenarios 1 and 2:

- In the peak load case, 50% (approx. 40 GWh/h) of the entry capacity from LNG terminals used in scenario 3 is assumed to be used. Since transmission system operators have no information about the status of capacity bookings for individual LNG terminals in 2037 that could be used to forecast future utilisation, utilisation is assumed to be the same for all LNG entry capacities in scenario 3 in 2037.
- Additional entry capacities are assumed for each gas transmission system operator in accordance with the respective network topology. The capacity level is generally based on scenario 3, although further reductions were usually made by the gas transmission system operators, including in cases where the methane infrastructure required for transportation was taken into account in the hydrogen modelling of scenarios 1 or 2 and the pipeline could be dispensed with in the methane scenario.
- As a result, the balance shows a surplus of 31 GWh/h (scenario 1) and 39 GWh/h (scenario 2), which is deliberately shown to illustrate grid flexibility.

Scenario 3:

- The firm FAC at cross-border IPs, storage facilities and LNG terminals determined as a sufficient level is used as entry capacity. For entries from LNG terminals, entry capacities of 79.7 GWh/h are used in accordance with the approved Scenario Framework.
- In addition, further firm capacities of cFAC and DAC types are used, which are based on the current capacity level of the individual points. For fDAC earmarked for power plants, the capacity level at the balancing entry point is adjusted so that it corresponds to the exit capacity of the assigned power plant as specified in the scenario.
- In some cases, interruptible capacities are used, particularly at cross-border IPs, in order to achieve an overall balance for the German market area.
- The result is a slight surplus of 1.3 GWh/h.

Figure 22: Entry and exit capacities in scenarios 1–3 (2037) and scenario 4 (2030) in the peak load case



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 19: Entry and exit capacities in scenarios 1–3 (2037) and scenario 4 (2030) in the peak load case

	Scenario 1 (2037)	Scenario 2 (2037)	Scenario 3 (2037)	Scenario 4 (2030)
	GWh/h			
Total entries	**214**	**218**	**320**	**425**
- thereof biomethane, production	2	2	2	4
- thereof storage	89	93	128	186
- thereof LNG	39	39	79	83
- thereof cross-border IPs	84	84	111	152
Total exits	**183**	**179**	**319**	**426**

Source: Coordination Office for Gas and Hydrogen Network Development Planning

The entry capacities from storage facilities shown in the table can alternatively be compensated for in large part by additional firm (scenarios 1 and 2) or interruptible (scenario 3) entry capacities at cross-border IPs, so that the achievability of these capacities can be assumed as given or irrelevant, taking into account the respective storage facility characteristics in the peak load case.

Entry capacities shown in the Gas NDP database

As with the peak load case described here, there is also some flexibility in terms of the entry point and the amount of entry capacities reported by gas transmission system operators in the Gas NDP database. In order to adequately reflect this flexibility in the Gas NDP database, the gas transmission system operators only report a total value for all individual points in the Gas NDP database per firm capacity type for the Trading Hub Europe market area for cross-border IPs, storage facilities and LNG terminals. The gas transmission system operators will continue to fine-tune the allocation of firm capacities to individual points in future network development plans in consultation with market participants based on the information available at that time.

6.1.2 Hydrogen scenarios 1–3 for the year 2037

Chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**and chapter 3.4 describe the basic approach to hydrogen modelling (e.g. regionalisation and load cases). The modelling process involves determining the necessary measures based on different load cases to illustrate the specified entry and exit capacities.

The load cases are based on the requirements of the BNetzA, which has defined the maximum exit capacities and minimum entry capacities for each hydrogen scenario in its approved Scenario Framework. These requirements are compared below for each scenario in the form of hydrogen balances for 2037.

6.1.2.1 Hydrogen exit capacity demand

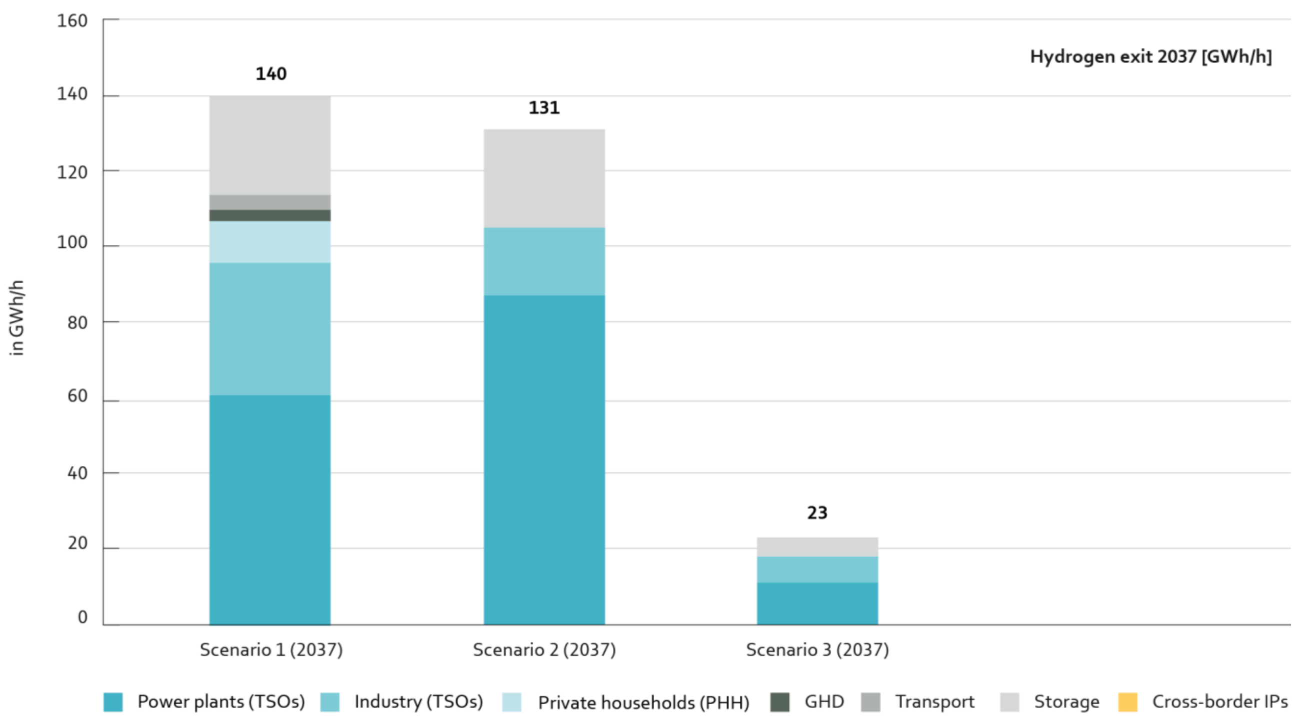
The hydrogen exit capacity demand is calculated as the sum of the following individual requirements:

- Gas-fired power plants are considered as per the approved Scenario Framework (chapter 3.4.3.1). Based on the results of the market survey and our own plausibility checks, the specified electrical capacity in the approved Scenario Framework was converted into a hydrogen connection capacity.

- The industrial, PHH, CTS and transport sectors are assessed in accordance with the approved Scenario Framework (chapters 3.4.3.2 and 3.4.3.3).
- The exit capacities for storage facilities were considered as per the specifications of the BNetzA in the approved Scenario Framework and the results of the market survey.
- No capacities have been considered for hydrogen cross-border IPs for the modelling year 2037. In accordance with the approved Scenario Framework, the capacity that can be achieved without an expansion must be determined here.

The following figure shows the hydrogen exit capacity of the scenarios for 2037.

Figure 23: Exit capacities for scenarios 1–3 (2037)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 20: Exit capacities for scenarios 1–3 (2037)

Exit capacities for hydrogen 2037	Scenario 1	Scenario 2	Scenario 3
	GWh/h		
Power plants	61	87	11
Industry	35	18	7
PHH	11	—	—
CTS	3	—	—
Traffic	4	—	—
Cross-border IPs	—	—	—
Storage	26	26	5
Total exits	**140**	**131**	**23**

Source: Coordination Office for Gas and Hydrogen Network Development Planning

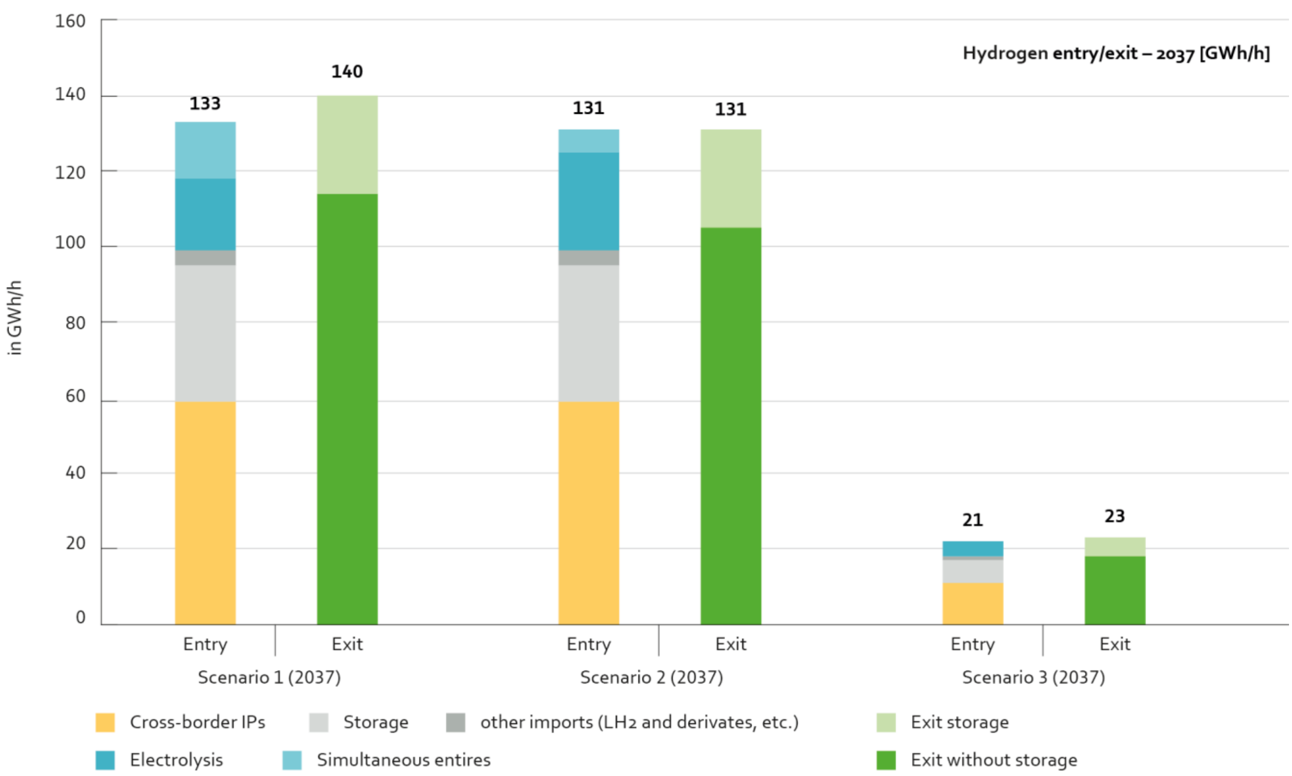
Scenario 1 shows the highest hydrogen demand. In this scenario, hydrogen is used in all sectors. In scenario 2, only exit capacities in the power plant and industry sectors are specified, with a different distribution than in scenario 1. Scenario 3 shows a delayed transition to hydrogen due to the overall very low maximum exit capacities.

6.1.2.2 Hydrogen entry capacity demand

To meet the exit capacity demand, imports via cross-border IPs, withdrawals from storage, other imports (including LH_2 and derivatives) and electrolysis projects are included. The entry capacity must cover the specified exit capacity in each load case. Where the minimum entry capacity specified in the approved Scenario Framework is insufficient, additional potential via cross-border IPs or storage facilities has been included in individual load cases (chapter 3.4.4). In scenario 2, the electrolysis capacity is specified by the approved Scenario Framework, which is consistent with scenario B of the Electricity Network Development Plan.

The following diagram shows the exit and entry capacities in each of the scenarios.

Figure 24: Hydrogen entry and exit capacities in scenarios 1–3 (2037)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 21: Hydrogen entry and exit capacities in scenarios 1–3 (2037)

Hydrogen entry and exit capacities in 2037	Scenario 1	Scenario 2	Scenario 3
	GWh/h		
Total entries	**133**	**131**	**21**
- thereof cross-border IPs	59	59	11
- thereof storage	36	36	6
- thereof other projects (including LH_2 and derivatives)	4	4	1
- thereof electrolysis	19	26	4
- thereof additional entry capacity*	15	6	—
- thereof cross-border IPs	11	4	—
- thereof storage	4	2	—
Total exits	**140**	**131**	**23**
- thereof storage	26	26	5
- thereof exits without storage	**114**	**105**	**18**

* only in *dark doldrums* load case; see explanation

Source: Coordination Office for Gas and Hydrogen Network Development Planning

In the *dark doldrums* load case, in scenarios 1 and 2, the exit flows cannot be fully balanced by the specified minimum entry capacities. System balancing is therefore ensured by additional entries from storage facilities and via cross-border interconnection points, with the additional capacity required being apportioned equally between both entry sources.
The additional entries from storage facilities (4.3 GW in scenario 1 and 2.4 GW in scenario 2) are allocated exclusively to storage projects at the "initial assessment/feasibility study" stage or beyond. These comprise four sites in the federal states of Bavaria, Brandenburg, Lower Saxony and Thuringia. Additional entries at cross-border interconnection points (10.5 GW in scenario 1 and 3.8 GW in scenario 2) are included selectively, based on technical consultations with the relevant network operators, where additional entry potential at cross-border interconnection points has been identified for 2037. All additional capacities are included in the modelling in a way that supports network operation during periods of low wind and low solar capacity (Table 21).

6.1.2.3 Entry capacities at cross-border interconnection points

The integration of the German hydrogen transmission network into the European infrastructure is essential for supplies. The minimum entry capacity at cross-border IPs specified in the approved Scenario Framework is around 59 GWh/h, which also corresponds to the cross-border IP entry capacities used for hydrogen core network modelling. The following table shows the distribution of entry capacities at cross-border IPs in the three scenarios for the modelling year 2037.

Table 22: Hydrogen entry capacities at cross-border IPs (2037)

Country	Cross-border IPs	Scenario 1	Scenario 2	Scenario 3
		Entries [GWh/h]		
Denmark	Bornholm-Lubmin	10.0	10.0	1.9

Country	Cross-border IPs	Scenario 1	Scenario 2	Scenario 3
		Entries [GWh/h]		
	Ellund	4.3	4.3	0.8
Norway/ UK	AquaDuctus (offshore)	5.0 (8.6)*	5.0 (6.3)*	0.9
	Dornum/ Emden	0.0	0.0	0.0
Netherlands	Oude Statenzijl/Bunde	4.0	4.0	0.8
	Vlieghuis	1.3	1.3	0.2
	Elten	3.2	3.2	0.6
	Vreden	3.2	3.2	0.0
Belgium	Eynatten	3.8 (5.8)*	3.8 (4.5)*	0.7
France	Medelsheim	8.0	8.0	1.5
	Freiburg	0.5	0.5	0.5
	Leidingen	0.2	0.2	0
Switzerland	Wallbach	0.0	0.0	0.0
Austria	Überackern	6.3	6.3	1.2
Czech Republic	Waidhaus	6.0 (6.3)*	6.0 (6.1)*	1.1
	Deutschneudorf	0.0	0.0	0.0
Poland	Oder-Spree	2.0 (6.6)*	2.0 (3.7)*	0.4
	Uckermark	0.8	0.8	0.2
Total		**58.6 (69.2)***	**58.6 (62.4)***	**10.7**

* Including additional entry capacity to balance the system during the *dark doldrums* load case

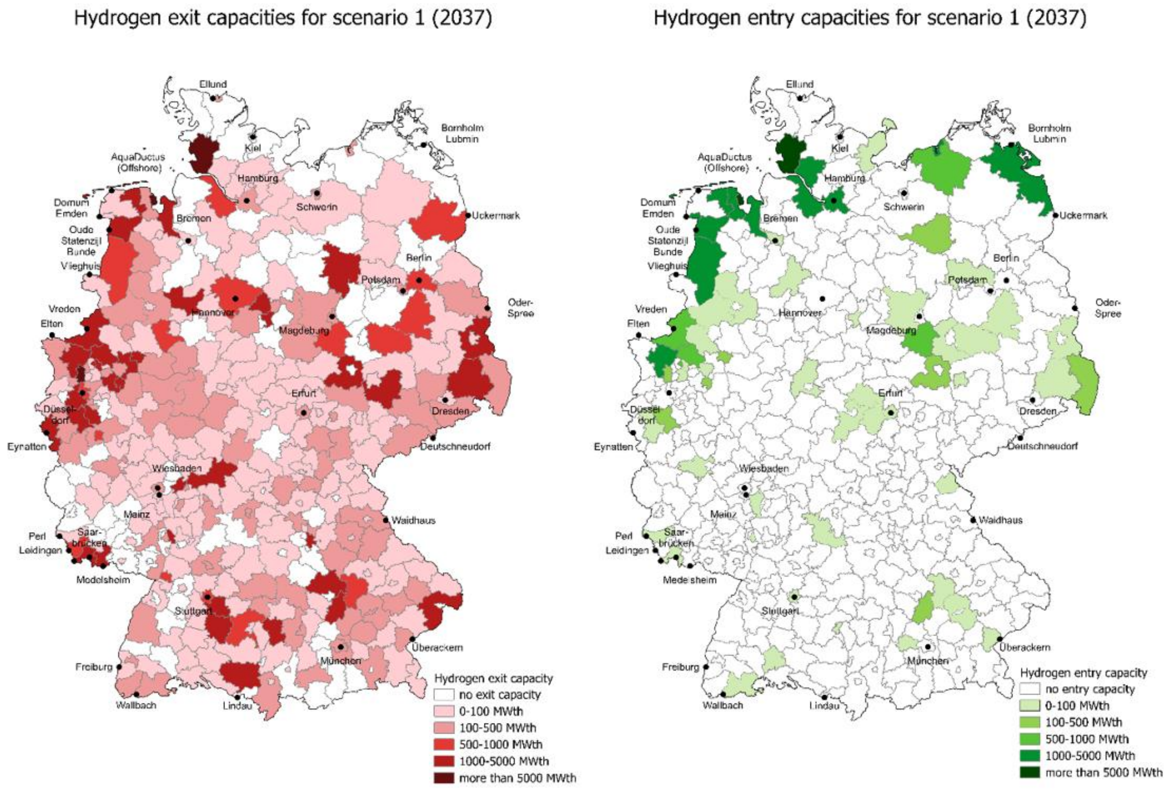
** Transit capacity of up to 6.6 GWh/h considered

Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.1.2.4 Entry and exit capacities at district level

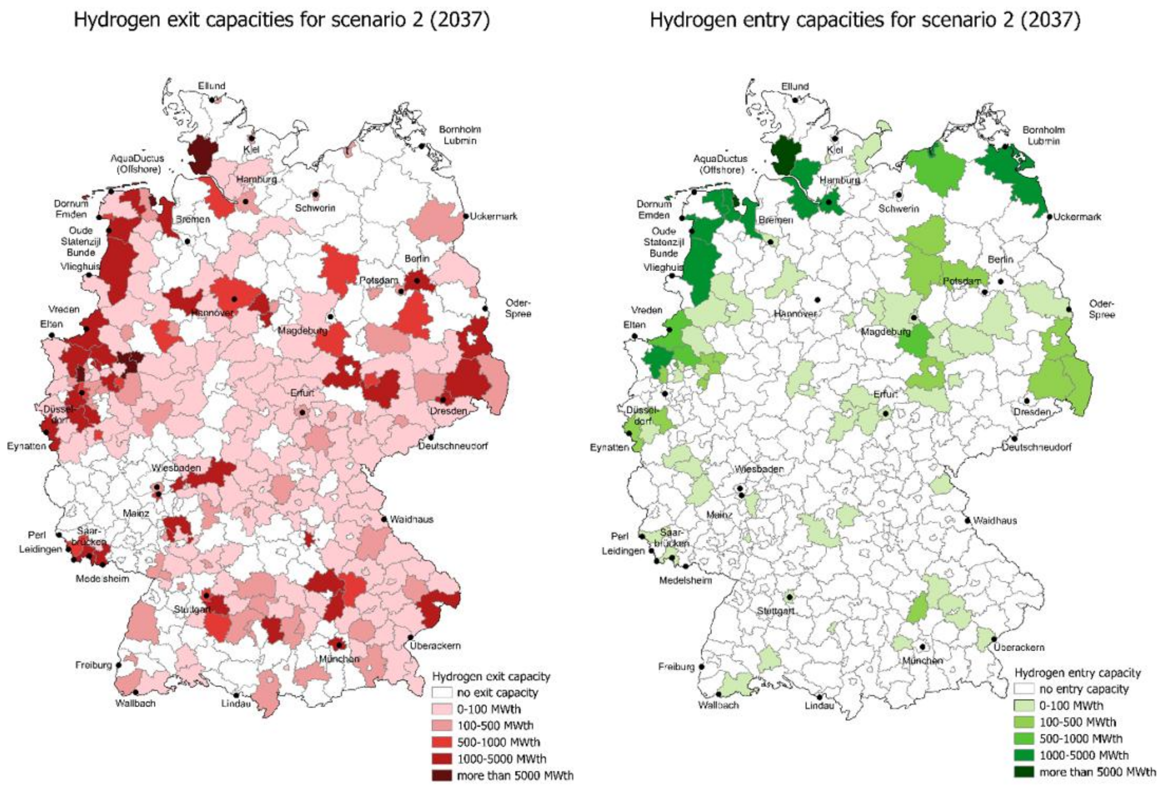
The following maps show the distribution of entry and exit capacities (excluding cross-border IPs) at district level.

Figure 25: Entry and exit capacities for scenario 1 (2037) at district level w/o cross-border IPs



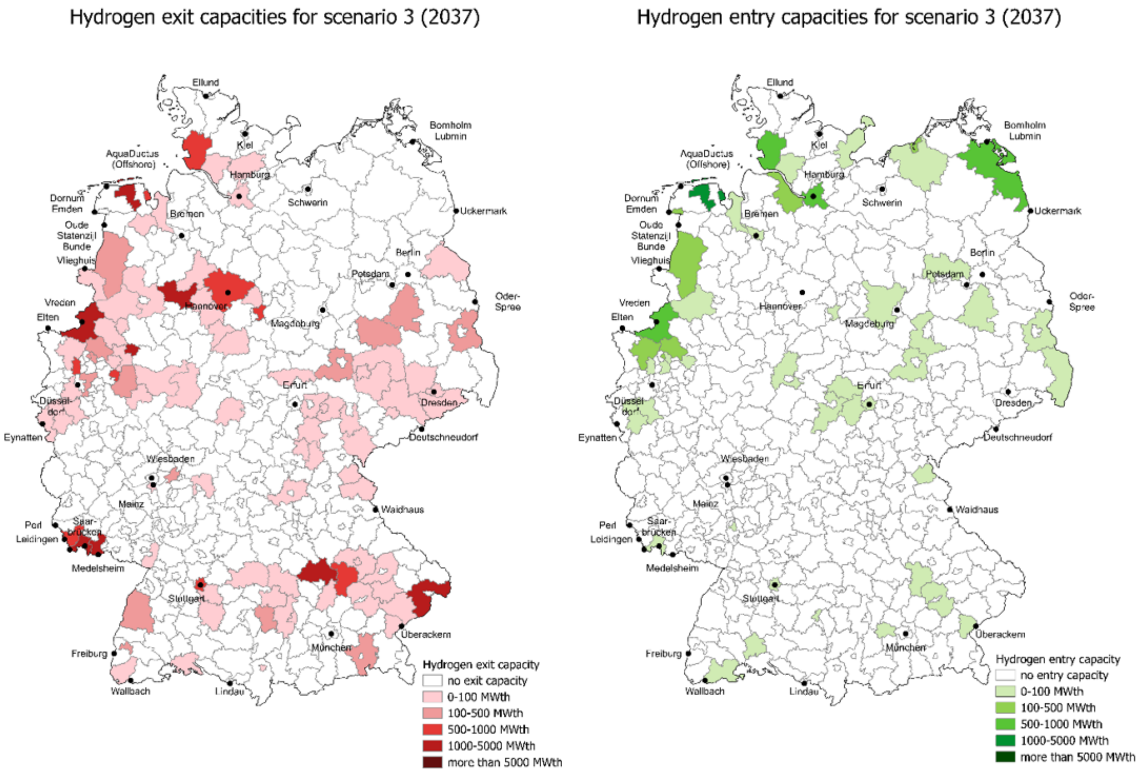
Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 26: Entry and exit capacities for scenario 2 (2037) at district level w/o cross-border IPs



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 27: Entry and exit capacities for scenario 3 (2037) at district level w/o cross-border IPs



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.2 Methane and hydrogen modelling results for the year 2037

This chapter shows the results of the scenario-based modelling process for the modelling year 2037. A distinction is made between methane and hydrogen as energy sources. The results for all three methane scenarios can be found in chapter **Fehler! Verweisquelle konnte nicht gefunden werden.** , while the results for hydrogen are presented in chapter 6.2.2.

There are significant differences in the way the results are presented: For methane, there are measures that were already approved as part of earlier network development plans. These measures are part of the starter network (chapter 4.2) once the execution has reached an advanced stage. Where measures are not part of the starter network, they were reviewed again and are included in the modelling results if they are still required. These measures are shown separately in the presentation of the results. The conversion of pipelines to hydrogen may also require natural gas-reinforcing measures on the methane side to ensure security of supply in the methane network. The relevant measures are also shown separately. Another category includes new construction measures for power generation and industry. Network expansion projects designed to meet power plant demand allow new generation capacity to be connected to the grid to help meet growing electricity demand, driven in part be increasing electrification, while newbuild projects measures for industry are aimed at increasing production capacities and improving security of supply for industrial customers.

In the hydrogen sector, there are measures approved as part of the core network which have to be reviewed in accordance with the Network Development Plan's statutory mandate to determine their necessity for commissioning dates after 2027. Measures after 2027 are included in the model, provided they are still required. A pipeline project can be delivered either by building a new pipeline or converting an existing pipeline to methane. The options are reflected in the results. Natural gas-reinforcing measures are – by definition – not a result of hydrogen modelling. For these reasons, the presentation of the results for hydrogen differs from that for methane.

The two chapters mentioned above only present the modelling results of the scenarios. At this stage, the measures shown do not represent the network expansion proposal. The methodology for deriving the network expansion proposal from the results of the modelling exercise and the resulting proposal are explained in chapter 7.

A description of the measures identified can be found in the Gas NDP database under "Ausbaumaßnahmen" for both methane and hydrogen.

In their draft Gas and Hydrogen Network Development Plan 2025, the hydrogen transmission system operators have provided an overview of all locations for potential M&R stations for each scenario.
In the revised draft, the hydrogen transmission system operators identify all hydrogen M&R stations and ancillary facilities in the Gas NDP database as measures for which operational management and control arrangements have been agreed. The focus here is primarily on facilities needed in the early years of the hydrogen ramp-up. Further sites for potential M&R stations in each scenario, for which operational management and control arrangements have not yet been finalised, are presented in **Fehler! Verweisquelle konnte nicht gefunden werden.**. Further details for these sites will be provided in future network development plans.

Chapter 6.2.3 includes the cross-analysis of scenarios 2 (hydrogen) and 3 (methane) for 2037 required by the BNetzA.

The analysis of the hydrogen export capacities that can be provided without expansion at cross-border IPs for the year 2037 can be found in chapter 6.2.4.

6.2.1 Methane modelling results for scenarios 1–3 for the year 2037

This chapter presents the results of the modelling exercise in the form of tables and figures. The tables include the technical parameters, such as pipeline lengths and plant capacities, as well as the capex details. The capex figures are provided for each of the measure categories. The conversion measures are shown as part of the methane transmission network presented.

The starter network measures are presented in chapter 4.2.

The total investment across all scenarios ranges from €2.2 billion to €2.7 billion. The modelling results for scenarios 1 and 2 are very similar, as the specified exit capacity is also almost identical. The capex difference of approximately €0.5 billion is mainly due to the conversion of a methane pipeline to hydrogen to cover the hydrogen demand in scenario 1, which exceeds the hydrogen requirements of scenarios 2 and 3. Given the integrated approach to both energy sources, this conversion results in a natural gas-reinforcing measure required in the corresponding scenario 1 for methane. Due to the higher methane demand in scenario 3 compared to scenarios 1 and 2, especially for power plants and industry, this scenario requires additional measures to be executed, resulting in the highest total investment overall.

6.2.1.1 Scenario 1 (2037)

The results of scenario 1 (2037) are presented in Table 22 and in Figure 28.

Table 23: Methane modelling results for scenario 1 (2037)

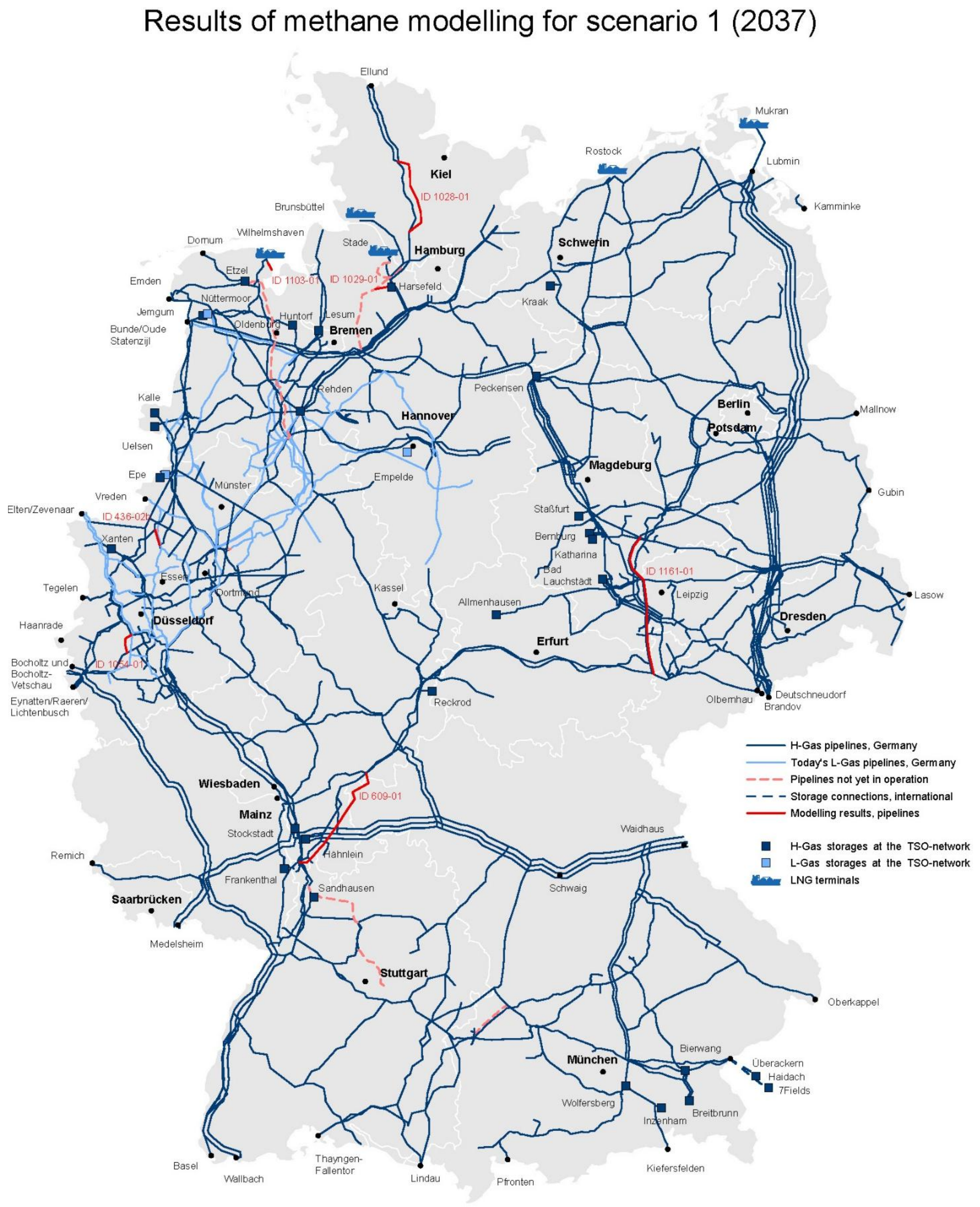
Results for scenario 1 for the year 2037*	By 2037
Technical parameters	
Pipelines [km]**	685
Compressor capacity [MW]	0
Total investment [billion euros]	**2.5**
- of which network expansion measures from NDP 2022	0.8
- of which natural gas-reinforcing measures from NDP 2022 and core network	1.2
- of which new network expansion measures for power plants and industrial needs	0.1
- of which new natural gas-reinforcing measures	0.5

* rounded figures

** includes pipeline lengths of all measures

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 28: Methane modelling results for scenario 1 (2037)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.2.1.2 Scenario 2 (2037)

The results of scenario 2 (2037) are presented in Table 24 and in Figure 29.

Table 24: Methane modelling results for scenario 2 (2037)

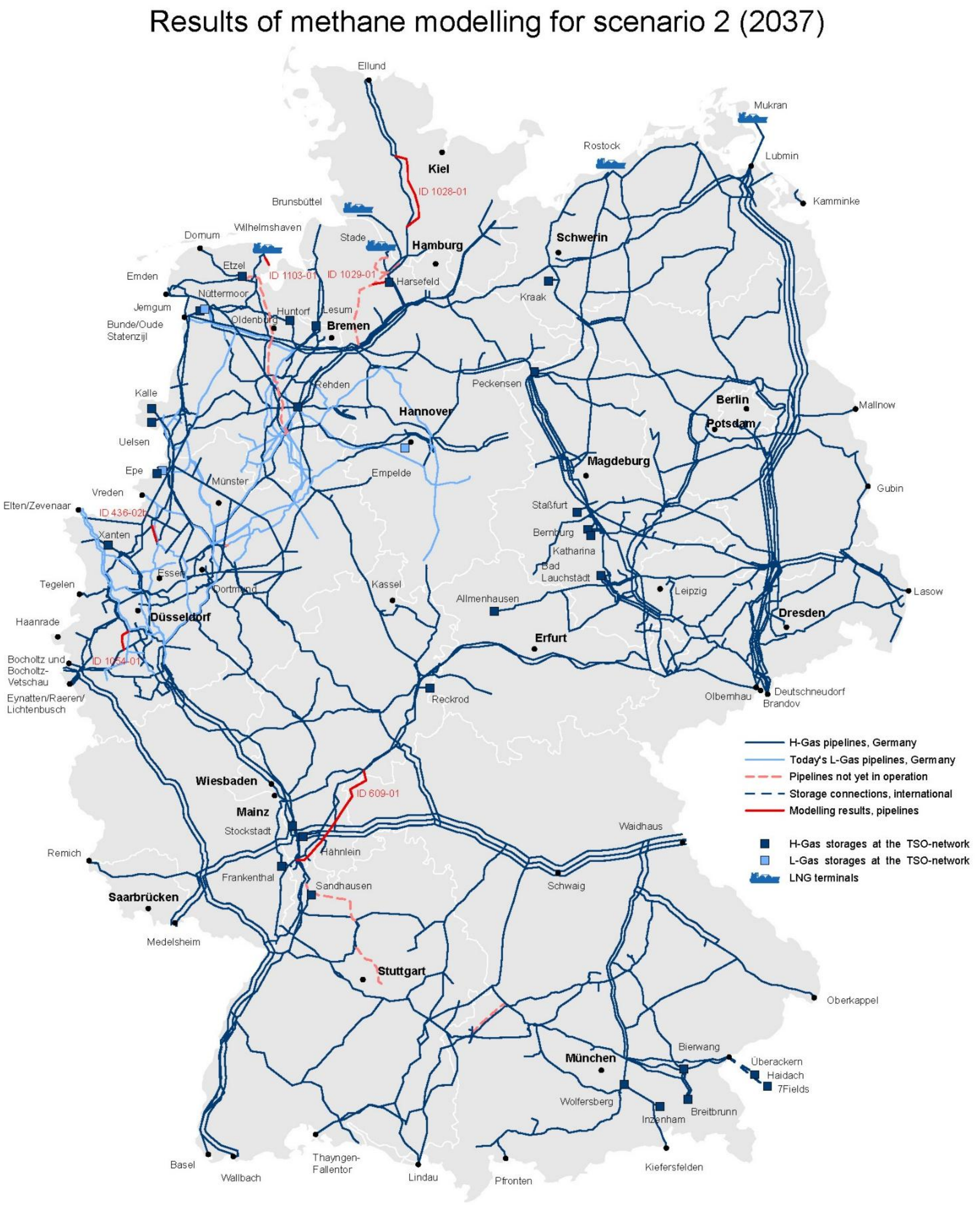
Results for scenario 2 for the year 2037*	**By 2037**
Technical parameters	
Pipelines [km]**	565
Compressor capacity [MW]	0
Total investment [billion euros]	**2.2**
- of which network expansion measures from NDP 2022	0.8
- of which natural gas-reinforcing measures from NDP 2022 and core network	1.2
- of which new network expansion measures for power plants and industry	0.1
- of which new natural gas-reinforcing measures	0.2

* rounded figures

** includes pipeline lengths of all measures

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 29: Methane modelling results for scenario 2 (2037)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.2.1.3 Scenario 3 (2037)

The results of scenario 3 (2037) are presented in the Table 25 and in Figure 30.

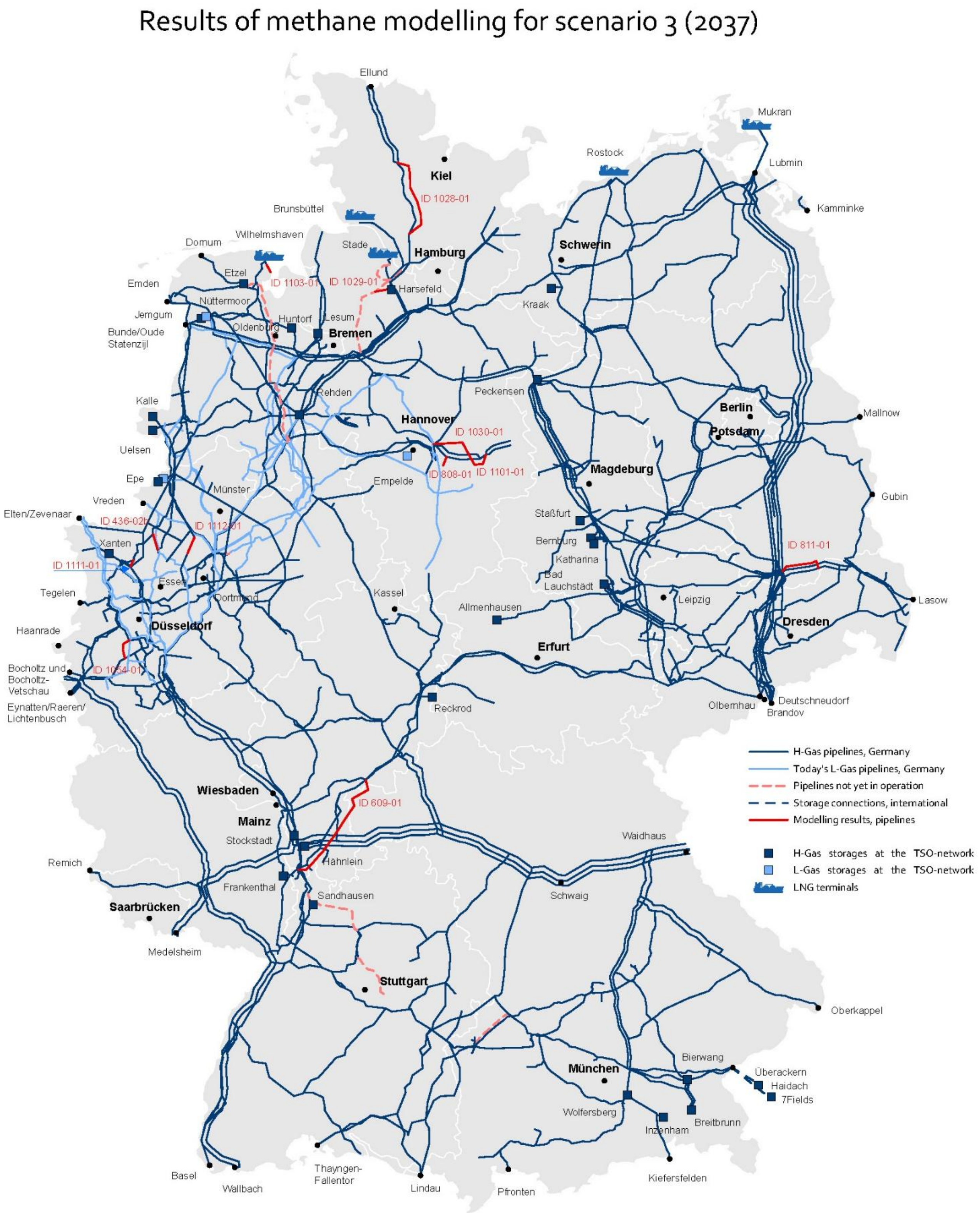
Table 25: Methane modelling results for scenario 3 (2037)

Results for scenario 3 for the year 2037*	By 2037
Technical parameters	
Pipelines [km]**	670
Compressor capacity [MW]	0
Total investment [billion euros]	**2.7**
- of which network expansion measures from NDP 2022	0.9
- of which natural gas-reinforcing measures from NDP 2022 and core network	1.4
- of which new network expansion measures for power plants and industry	0.3
- of which new natural gas-reinforcing measures	0.1

* rounded figures
** includes pipeline lengths of all measures

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 30: Methane modelling results for scenario 3 (2037)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.2.2 Hydrogen modelling results for scenarios 1–3 for the year 2037

This chapter presents the results of the modelling exercise for the three scenarios for the year 2037 and the starter network (chapter 4.2). The results for pipeline projects in scenarios 1 and 2 differ only slightly, but there is a significant difference in compressor capacities. The pipeline lengths and compressor capacities for both scenarios exceed the approved figures for the hydrogen core network. In terms of pipeline length, scenario 3 is significantly below the hydrogen core network because of the lower capacity requirements.

6.2.2.1 Scenario 1 (2037)

The results of scenario 1 (2037) are presented in Table 26 and in Figure 31.

Table 26: Hydrogen modelling results for scenario 1 (2037) and the hydrogen starter network

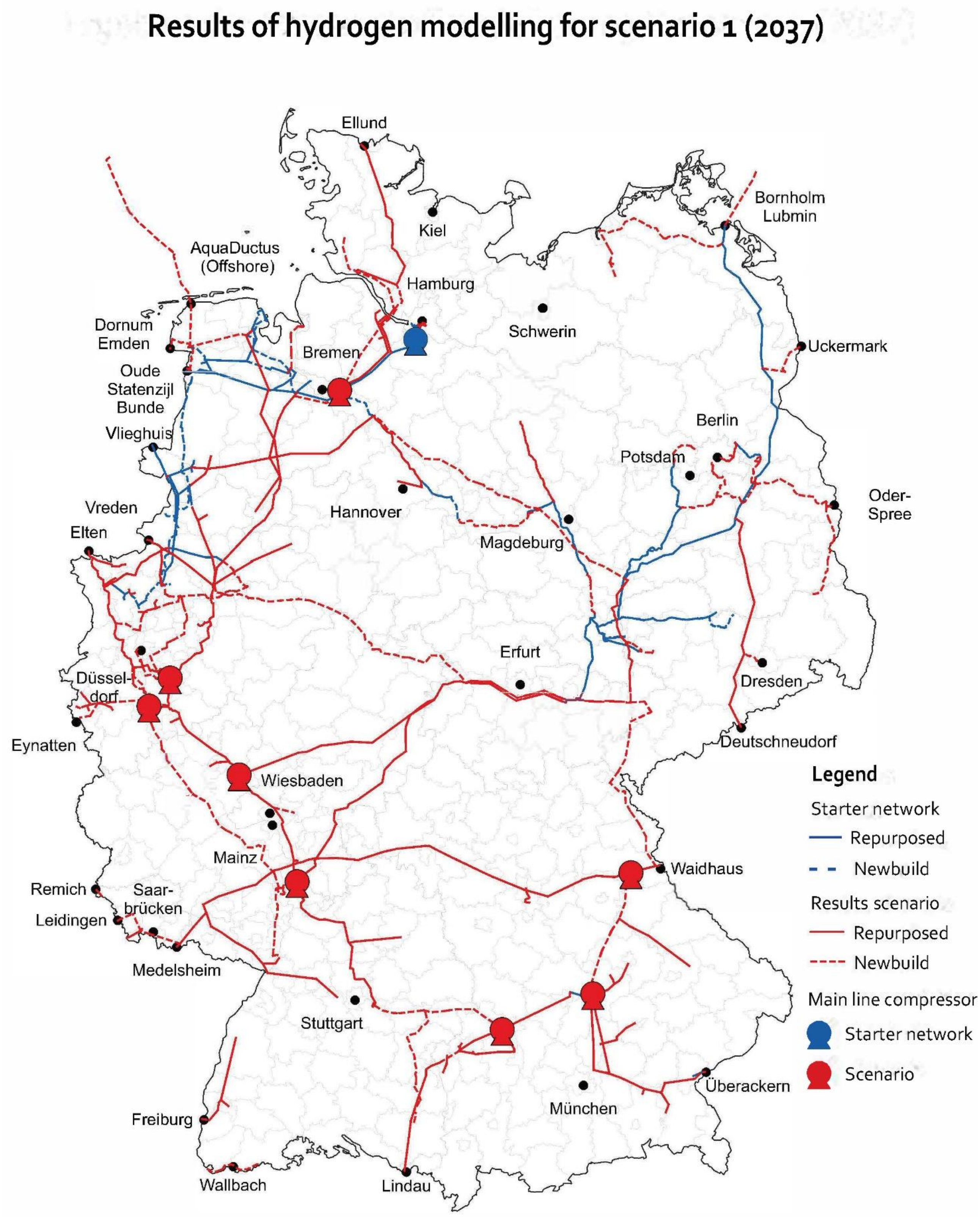
Results for scenario 1 for the year 2037*	Starter network	By 2037	Starter network and results for scenario 1 for 2037
Technical parameters			
Compressor capacity [MW]	6	761	767
Pipelines [km]	2,201	8,229	10,430
- of which pipelines to be repurposed [km]	1,599	4,727	6,326
- of which newly built pipelines [km]	602	3,316	3,918
- of which newly built pipelines (offshore) [km]	0	186	186
- For information: Czech-German Hydrogen Interconnector (CGHI)** [km]		168	
Total investment [billion euros]	**4.0**	**25.8**	**29.8**
Compressor stations	0.1	5.4	5.5
Pipelines (incl. M&R station costs)	4.0	20.3	24.3
- of which pipelines to be repurposed	1.1	3.2	4.4
- of which newly built pipelines	2.9	15.2	18.1
- of which newly built pipelines (offshore) incl. ancillary facilities	0.0	1.9	1.9

* rounded figures

** CGHI has been taken into account for the modelling but is not part of the German hydrogen network.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 31: Hydrogen modelling results for scenario 1 (2037)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.2.2.2 Scenario 2 (2037)

The results of scenario 2 (2037) are shown in Table 27 and in Figure 32.

Table 27: Hydrogen modelling results for scenario 2 (2037) and the hydrogen starter network

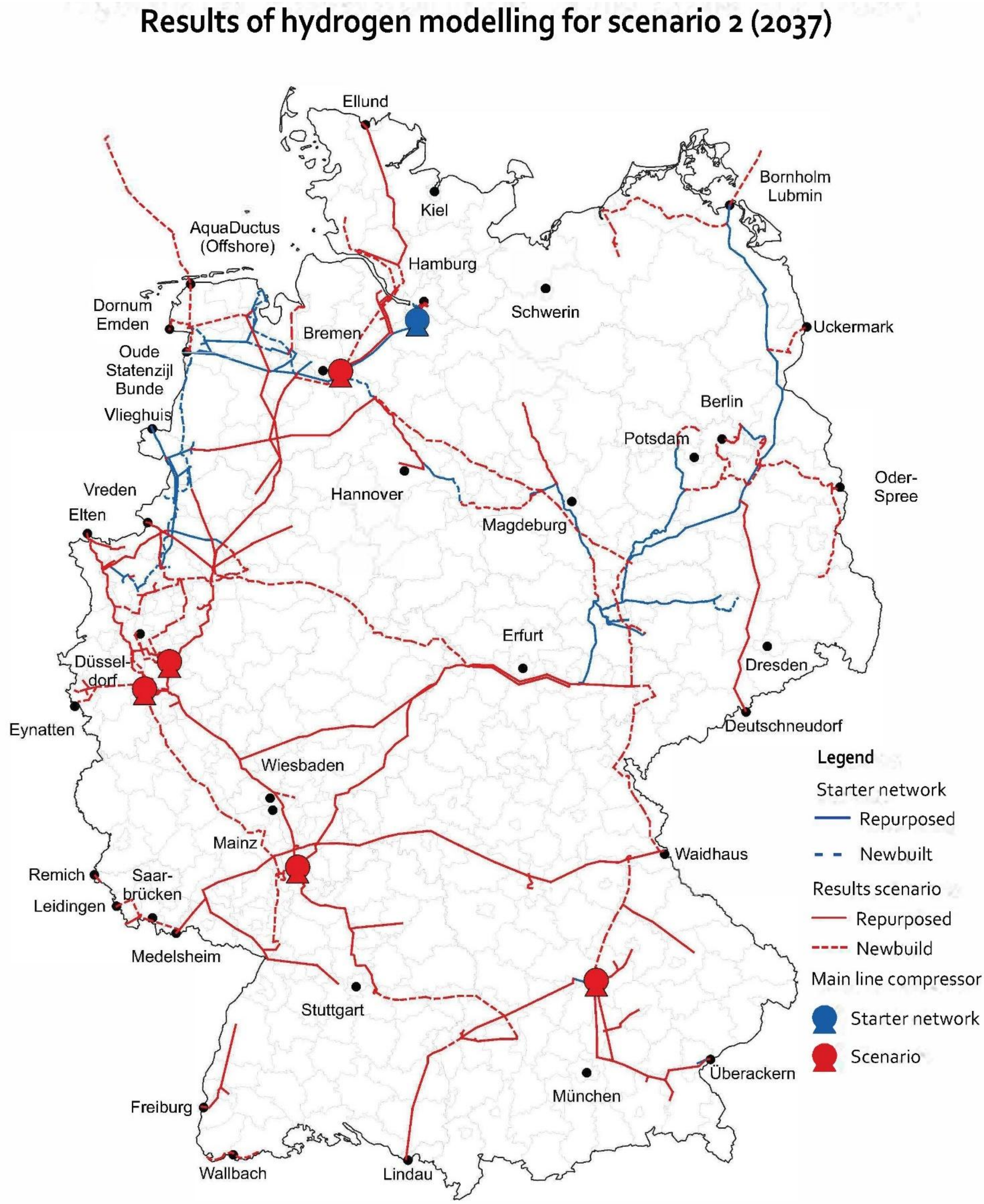
Results for scenario 2 for the year 2037*	Starter network	By 2037	Starter network and results for scenario 2 for 2037
Technical parameters			
Compressor capacity [MW]	6	520	526
Pipelines [km]	2,201	7,998	10,199
- of which pipelines to be repurposed [km]	1,599	4,514	6,112
- of which newly built pipelines [km]	602	3,298	3,901
- of which newly built pipelines (offshore) [km]	0	186	186
- For information: Czech-German Hydrogen Interconnector (CGHI)** [km]		168	
Total investment [billion euros]	**4.0**	**24.1**	**28.1**
Compressor stations	0.1	4.0	4.0
Pipelines (incl. M&R station costs)	4.0	20.1	24.1
- of which pipelines to be repurposed	1.1	3.1	4.2
- of which newly built pipelines	2.9	15.1	18.0
- of which newly built pipelines (offshore)	0.0	1.9	1.9

* rounded figures

** CGHI was taken into account in the modelling but is not part of the German hydrogen network.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 32: Hydrogen modelling results for scenario 2 (2037)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.2.2.3 Scenario 3 (2037)

The results of scenario 3 (2037) are shown in Table 28 and in Figure 33.

Table 28: Hydrogen modelling results for scenario 3 (2037) and for the hydrogen starter network

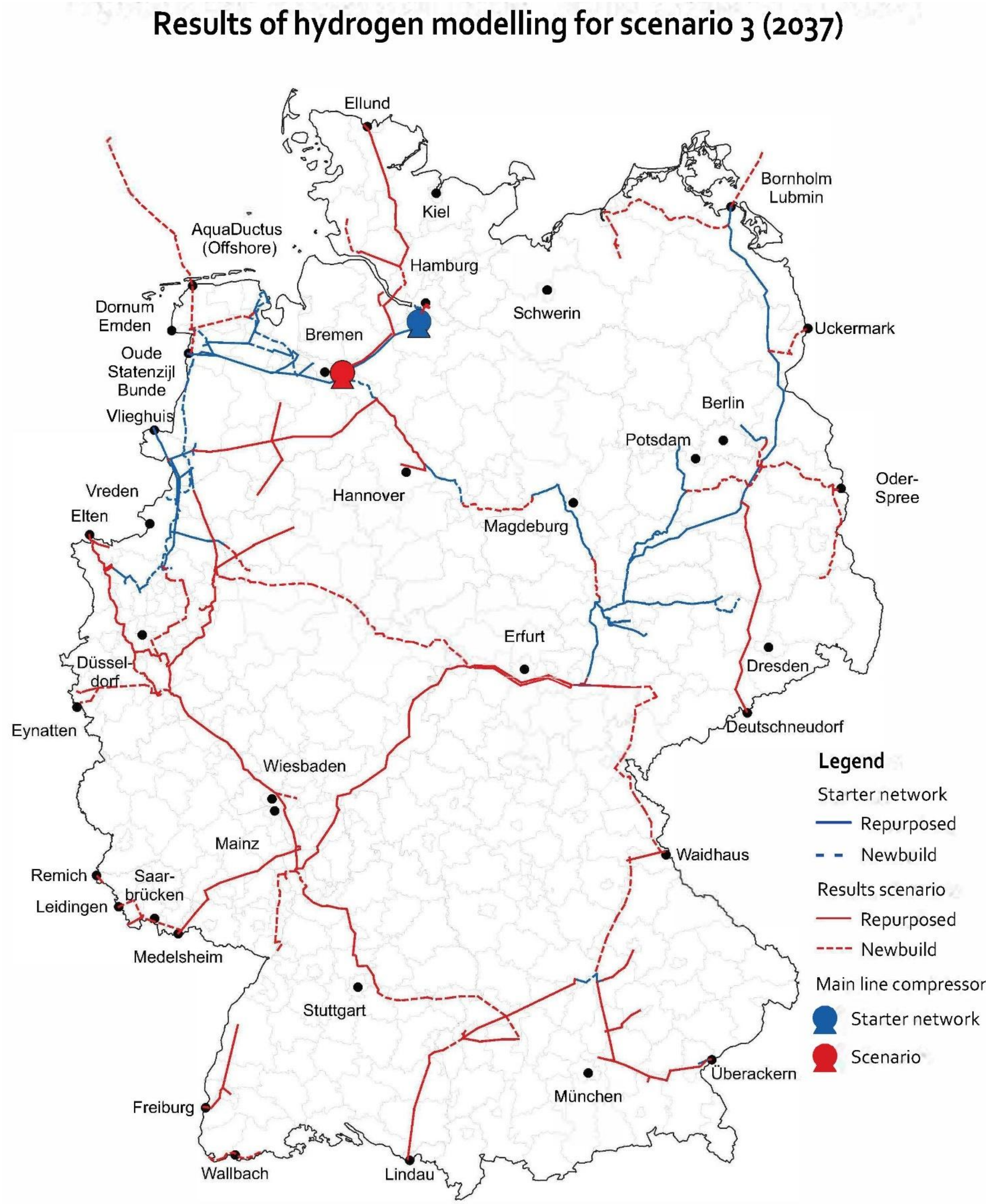
Results for scenario 3 for the year 2037*	Starter network	By 2037	Starter network and results for scenario 3 for 2037
Technical parameters			
Compressor capacity [MW]	6	8	14
Pipelines [km]	2,201	5,232	7,433
- of which pipelines to be repurposed [km]	1,599	2,956	4,554
- of which newly built pipelines [km]	602	2,091	2,693
- of which newly built pipelines (offshore) [km]	0	186	186
- For information: Czech-German Hydrogen Interconnector (CGHI)** [km]	168		
Total investment [billion euros]	**4.0**	**13.1**	**17.1**
Compressor stations	0.1	0.1	0.1
Pipelines (incl. M&R station costs)	4.0	13.0	17.0
- of which pipelines to be repurposed	1.1	2.0	3.1
- of which newly built pipelines	2.9	9.1	12.0
- of which newly built pipelines (offshore)	0.0	1.9	1.9

* rounded figures

** CGHI has been taken into account in the modelling but is not part of the German hydrogen network.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 33: Hydrogen modelling results for scenario 3 (2037)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.2.3 Cross-analysis of scenarios 2 and 3

In its approval of the Scenario Framework, the BNetzA instructs the hydrogen transmission system operators to determine the pipelines that can be repurposed for the hydrogen transmission system in scenario 2 based on the gas transmission system in scenario 3.

Even though a high hydrogen demand (scenario 2) in combination with a continued high methane demand (scenario 3) in 2037 must be considered relatively unlikely, the hydrogen transmission system operators have carried out the requested cross-analysis of scenarios 2 and 3. To this end, they examined which pipelines were confirmed as available for conversion in scenario 2 (methane) but were identified unavailable in scenario 3 (methane).

Since these pipelines are not available for repurposing from the cross-analysis perspective, corresponding newbuild pipelines were assumed instead as part of the modelling of scenario 3 (hydrogen). In scenario 2, a large part of the additional transportation demand is met by additional compressors, so that in the cross-analysis, no further expansion of compressor capacity is required and the transportation demand can instead be met by newly built pipelines. The results obtained by this approach are as follows.

The cross-analysis identified 17 pipelines that can be converted to hydrogen in scenario 2 but are unavailable for conversion in scenario 3 due to the higher methane demand identified in this scenario. Table 29 provides an overview of these conversion measures. These measures have a total pipeline length of 1,101 kilometres. If newbuild costs are assigned to these measures instead of conversion costs, the pipeline costs for these hydrogen projects increase by around €4.3 billion for scenario 3 (2037).

Table 29: Conversion measures resulting from cross-analysis

No.	NDP ID	Name of expansion measure	Length [in kilometres]
1	H2-0208	Einmuß-Kelheim pipeline incl. M&R stations	8.2
2	H2-0210	Broadbrunn-Bierwang pipeline incl. M&R stations	18.6
3	H2-0216	Mittelbrunn-Au am Rhein pipeline incl. M&R stations	79.0
4	H2-0067	H2ercules Vreden-Gescher pipeline incl. M&R stations	13.1
5	H2-0068	H2ercules Gescher-Werne pipeline incl. M&R stations	56.3
6	H2-0069	H2ercules Gescher-Dorsten pipeline incl. M&R stations	31.6
7	H2-0219	Drohne-Werne pipeline incl. M&R stations	111.8
8	H2-0220	Lauterbach-Scheidt pipeline incl. M&R stations	124.6
9	H2-0221	Büchelberg-Karlsruhe pipeline incl. M&R stations	10.4
10	H2-0222	Etzel-Wardenburg pipeline incl. M&R stations	57.0
11	H2-0223	Wardenburg-Drohne pipeline incl. M&R stations	75.2
12	H2-0227	Lauterbach-Vitzeroda pipeline incl. M&R stations	67.6
13	H2-0085	H2 Hercules Rimpar-Rothenstadt pipeline incl. M&R stations	183.0
14	H2-0228	Schwandorf-Windberg pipeline incl. M&R stations	71.9
15	H2-0229	Steinitz-Wedringen pipeline incl. M&R stations	73.1
16	H2-0230	Au am Rhein-Leonberg pipeline incl. M&R stations	73.7
17	H2-0232	Kirchhausen-Waldenburg pipeline incl. M&R stations	45.9

Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.2.4 Analysis of exit capacities at cross-border IPs in the 2037 hydrogen network (H2 exit IPs)

In its approval of the Scenario Framework, the BNetzA did not specify any values for exit capacities at cross-border IPs in the hydrogen network for the reference year 2037. Rather, for the three scenarios, the hydrogen transmission system operators are to determine which exit capacities at cross-border IPs can be represented without the need for expansion, based on the hydrogen network determined for the year 2037 (see Chapter 6.2.2).

In the Scenario Framework approval, the BNetzA states the following in this regard:

"From the Federal Network Agency's perspective, however, transit flows cannot be completely disregarded in network development planning. Given its geographical location, Germany already plays a key role in the establishment and expansion of the European hydrogen infrastructure and in the supply and transit of hydrogen, which in the medium term will particularly affect its eastern and southeastern neighbouring countries."

To fulfil the mandate of establishing Germany as a central player in the development and expansion of the European hydrogen infrastructure, as well as in the supply and transit of hydrogen, three transit routes were therefore systematically examined in the scenarios underpinning the modelling.

- Transit route 1: From France/Belgium (Medelsheim/Eynatten) towards Poland (Uckermark/Oder-Spree), the Czech Republic (Deutschneudorf/Waidhaus) and Austria (Überackern)
- Transit route 2: From Denmark (Bornholm-Lubmin) towards Poland (Uckermark/Oder-Spree) and the Czech Republic (Deutschneudorf/Waidhaus)
- Transit route 3: From the Netherlands (Elten) to the cross-border IPs towards Poland (Uckermark/Oder-Spree) and the Czech Republic (Deutschneudorf/Waidhaus)

For each of these transit routes, the additional available transmission capacity requiring no network expansion was determined.

In the 2037 model, a maximum hydrogen exit capacity of 4 GWh/h was assumed for each transit route at the cross-border IPs. These capacities are allocated as exits, in full and as far as possible without requiring network expansion, on a pro rata basis to the cross-border IPs under consideration.

For each transit route, the most restrictive entry test load case is considered. In addition to the entry capacity assumed in the respective load case, the entry capacities shown in the tables below are assumed in order to provide the corresponding exit capacities. With the assumed entry capacities, the cross-border IP base capacities from the draft of the 2025 Scenario Framework are not exceeded.

The tables below show the results of the transit test for each scenario and show the additional transmission capacity available without capacity expansion at selected cross-border IPs for the three transit routes examined.

Table 30: Transit test results for scenario 1

	Cross-border IP	Scenario 1			
		Transit route 1		Transit route 2	Transit route 3
		FR/ BE → PL/ CZ/ AT		DK → PL/ CZ	NL → PL/ CZ
		Entry test EEbNW	Entry test South	Entry test EEbNW	Entry test South
Entry [MWh/h]	Medelsheim	4,000	---	---	---
	Eynatten	---	4,000	---	---
	Elten	---	---	---	3,200
	Bornholm-Lubmin	---	---	4,000	---
Exit [MWh/h]	Uckermark	200	200	725	500
	Oder-Spree	1,200	1,200	2,675	2,000
	Deutschneudorf	---	---	600	700
	Waidhaus	1,800	1,800	---	---
	Überackern	800	800	---	---

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 31: Transit test results for scenario 2

	Cross-border IP	Scenario 2			
		Transit route 1		Transit route 2	Transit route 3
		FR/ BE → PL/ CZ/ AT		DK → PL/ CZ	NL → PL/ CZ
		Entry test EEbNW	Entry test South	Entry test EEbNW	Entry test South
Entry [MWh/h]	Medelsheim	4,000	---	---	---
	Eynatten	---	4,000	---	---
	Elten	---	---	---	3,200
	Bornholm-Lubmin	---	---	4,000	---
Exit [MWh/h]	Uckermark	200	200	600	500
	Oder-Spree	1,200	1,200	2,200	2,000
	Deutschneudorf	---	---	1,200	700
	Waidhaus	1,800	1,800	---	---
	Überackern	800	800	---	---

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 32: Transit test results for scenario 3

	Cross-border IP	Scenario 3			
		Transit route 1		Transit route 2	Transit route 3
		FR/ BE → PL/ CZ/ AT		DK → PL/ CZ	NL → PL/ CZ
		Entry test EEbNW	Entry test South	Entry test EEbNW	Entry test South
Entry [MWh/h]	Medelsheim	200	---	---	---
	Eynatten	---	4,000	---	---
	Elten	---	---	---	3,200
	Bornholm-Lubmin	---	---	4,000	---
Exit [MWh/h]	Uckermark	10	200	600	500
	Oder-Spree	80	1,200	2,200	2,000
	Deutschneudorf	---	---	1,200	700
	Waidhaus	110	1,800	---	---
	Überackern	---	800	---	---

Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.3 Methane modelling results for scenario 3 for the year 2045

As requested in the approval of the Scenario Framework, the gas transmission system operators performed some detailed modelling for scenario 3 and, in an iterative process, determined a methane network remaining in 2045.

The BNetzA does not specify any domestic methane demand for scenarios 1 and 2; for both scenarios, the same transit and export capacities at cross-border IPs as in scenario 3 are assumed.

Starting with the input parameters for scenario 3 for methane in 2045, chapter 6.3.1 first describes the procedure and then presents the results of the modelling exercise in chapter 6.3.2.

The gas transmission system operators have decided not to present an additional methane network for scenarios 1 and 2, as no independent modelling has been carried out for these scenarios and the remaining methane networks in these scenarios will be clearly based on the methane network in scenario 3 in 2045 due to consistent assumptions regarding transit.

6.3.1 Input variables

The following subchapters describe the demand for exit capacity, the procedure for determining the methane network and the entry capacity demand, and the resulting entry capacities in the balancing case.

6.3.1.1 Exit capacity demand

In its approval of the Scenario Framework, the BNetzA specified an internal German methane demand for 2045 of 44 GWth (Table 6) in scenario 3 for the power plants that remain connected to the methane pipeline system. This figure is derived from the electrical connection capacity of 22 GW_e.

In addition, there is methane transit through Germany to supply neighbouring countries. As explained in chapter 3.3.1.4, the gas transmission system operators define an overall transit capacity demand from northern/western Europe to southern/eastern Europe for the current energy supply plans for these countries.

Given these circumstances, the exit capacity demand is calculated as the sum of the following individual requirements:

- Exit capacities for gas-fired power plants based on capacity requests submitted in accordance with Section 38 and 39 for GasNZV (German Gas Supply Ordinance), as in Table 33.
- Exit capacities at the cross-border IPs Deutschneudorf (Czech Republic), Wallbach/Basel (Switzerland), Lasow (Poland) and Oberkappel/Lindau (Austria) amounting to approximately 33% of the current firm capacities of the respective cross-border IPs in accordance with chapter 3.3.1.4. The gas transmission system operators intend to work with market participants to determine the extent to which additional export capacities are required, which could be shown, for example, as clearly defined transportation paths (cross-border IP to cross-border IP) for the design of the necessary infrastructure to be included in future network development plans.

Table 33: Power plant sites and gas connection ratings considered in scenario 3 (2045)

No.	Name of point/zone	Scenario 3 (2045) [MW_e]*	Scenario 3 (2045) [MW_{th}]
1	Unit 2 of the gas-fired power plant in Leipheim	475	950
2	Knapsack CHP / heat generation plant	140	280
3	Bergkamen	1,150	2,300
4	Profén Village CHP plant	17	33
5	Heilbronn gas turbine	600	1,200
6	Hanau gas-fired power plant	54	107
7	Rostock CCGT power plant	810	1,620
8	Schkopau CCGT power plant	783	1,565
9	Marbach CCGT power plant	825	1,650
10	Schwarze Pumpe CCGT power plant	833	1,665
11	Aalen CCGT plant	158	316
12	Altbach CCGT plant – unit 2	530	1,060
13	Altbach CCGT plant– unit 3	430	860
14	Mannheim CCGT plant	800	1,600
15	Scholven steam turbine power plant	835	1,670
16	Staudinger steam turbine power plant	835	1,670
17	Hamm Westphalia	625	1,250
18	Hürth	800	1,600
19	Innovative hybrid power plant in Boxberg	833	1,665
20	Innovative hybrid power plant in Jänschwalde	833	1,665
21	Innovative hybrid power plant in Lippendorf	833	1,665
22	Gundremmingen power plant	800	1,600
23	Mehrum power plant	100	200

No.	Name of point/zone	Scenario 3 (2045) [MW_e]*	Scenario 3 (2045) [MW_{th}]
24	Mehrum power plant	725	1,450
25	Frechen data centre	36	71
26	RWE Neurath power plant	800	1,600
27	RWE Niederaußem power plant	400	800
28	RWE Voerde	800	1,600
29	Steag Datteln	1,320	2,640
30	Steag Duisburg-Walsum	963	1,925
31	Steag Herne, unit 4	710	1,420
32	Voerde Schleusenstraße	404	808
33	Weisweiler II	800	1,600
34	Werne	750	1,500
	Total	**21,807**	**43,605**

* according to Scenario Framework approval

Source: Coordination Office for Gas and Hydrogen Network Development Planning

For scenarios 1 and 2, the BNetzA does not specify any domestic methane demand in Germany, so for both scenarios the same transit and export capacities at cross-border IPs are assumed as in scenario 3.

6.3.1.2 Procedure for determining the methane network and the demand for entry capacity

According to the approval of the Scenario Framework, only imports via cross-border IPs and, additionally for scenario 3, entries from storage facilities should be used to meet demand in the balancing case in 2045. However, the BNetzA has not specified any entries from LNG terminals in its approval of the Scenario Framework.

In order to determine the specific entry capacity demand levels for scenario 3, an estimate of the power plants' volume requirements was carried out based on the specified gas connection rating and an assumed full-load hour range of between 1,360 and 2,500 hours per year, which equates to a volume requirement of between 59 TWh and 109 TWh per year for the power plants. This volume estimate and the assumed cross-border IP export capacities for supplying neighbouring countries in 2045 were then used to determine the required entry capacities of the cross-border IPs and the storage facility in the pipeline network.

Based on the specific requirements for the exit side and the basic assumptions for the entry side, the gas transmission system operators used an iterative process to determine which methane infrastructure is needed to fulfil the specified transportation task. Starting from the point-specific power plant exit capacities, suitable transport infrastructures were identified in order to meet the power plants' regional demand (geographical connection). The next step was to determine the supra-regional connections and interconnections of the sub-networks identified in the previous step (Bavaria/Baden-Württemberg, North Rhine-Westphalia, Lower Saxony, Saxony/Saxony-Anhalt), which included cross-border connection options. It was assumed that a transport infrastructure between the German cross-border IPs Brandov and Waidhaus through the Czech Republic will still exist for north-south transport in 2045, the reason being that the transmission system operators did not want to plan two separate pipelines for north-south transport in Germany. When determining this regional and supra-regional infrastructure, the TSOs also paid attention to the connection of suitable underground storage facilities and the relevant cross-border

IPs. In general, connections to several cross-border IPs were taken into account on the entry side in order to include several import options.

Where more than one infrastructure was suitable for fulfilling the (particularly supra-regional) transport task, additional consideration was given to whether there was further transport demand in the region in the hydrogen modelling for 2045. In this case, the TSOs examined whether a specific methane pipeline infrastructure could be particularly suitable for this purpose due to its technical parameters. No independent volume estimate was carried out for scenarios 1 and 2, as the Federal Network Agency had not specified any power plant demand.

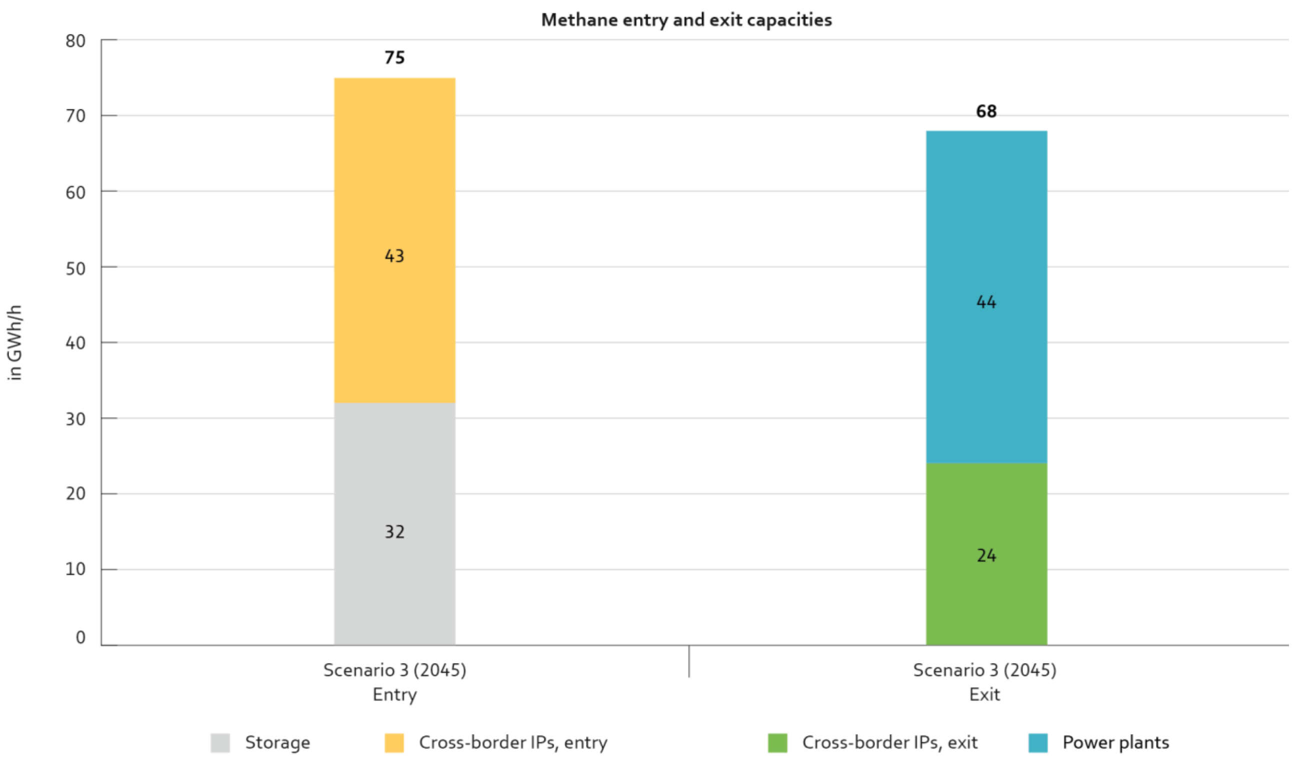
6.3.1.3 Resulting entry capacities in the balancing case

Based on the specified exit capacities and the iterative process for determining the methane network needed, the exit demand in the balancing case is met by the following entries in scenario 3:

- According to **Fehler! Verweisquelle konnte nicht gefunden werden.**, entries from a large number of storage facilities are used to reflect the power plants' spatial distribution and the resulting regional power demand. The storage facilities of Etzel, Uelsen, Rehden, Epe, Bierwang, 7Fields, Haidach, Bernburg, Bad Lauchstädt and Sandhausen were considered as examples for this balancing case. Other storage facilities may be assigned to the 2045 balance case if they are available in the methane network beyond 2045.
- In accordance with chapter 3.3.2.1, entries are essentially assigned via cross-border IPs to Denmark (Ellund), Norway (Emden, Dornum), the Netherlands (Bocholtz, Elten, Oude Statenzijl), Belgium (Eynatten) and France (Medelsheim).

A comparison of entry and exit demands provides the following balance for scenario 3 in 2045 (Figure 34).

Figure 34: Entry and exit capacities for scenario 3 (2045)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

The balance shown reveals a surplus of 7 GWh/h, which is reported by the transmission system operators in order to show a certain degree of flexibility on the entry side in supplying the exit volumes.

With regard to biomethane, the gas transmission system operators assume for all three scenarios that in 2045 there will be relevant biomethane production capacities in Germany, some of which will provide quantities for local consumption at the DSO level, but which could also – if located close enough – feed into the gas transmission system in order to make the quantities available for supra-regional consumption or export. Given the importance of this issue, it should be explored in more detail together with the DSOs as part of the regional transformation plan. For this reason, the gas transmission system operators have decided for the time being to refrain from taking specific biomethane entry capacities into account in the gas transmission system in 2045 until results from the transformation plan are available. Generally speaking, the gas transmission system in place in 2045 will be able to absorb and transport significant quantities of biomethane.

6.3.2 Modelling result for methane network in 2045

The methane network for scenario 3 in 2045 resulting from the process described above is shown in Figure 35. With a total length of approximately 5,500 km, the network comprises only a fraction of the length of today's gas transmission system of around 40,000 km but is appropriately sized for retaining and using essential parts of the storage infrastructure, for supplying gas to significant power plant capacities and for providing the required transits in accordance with the underlying assumptions.

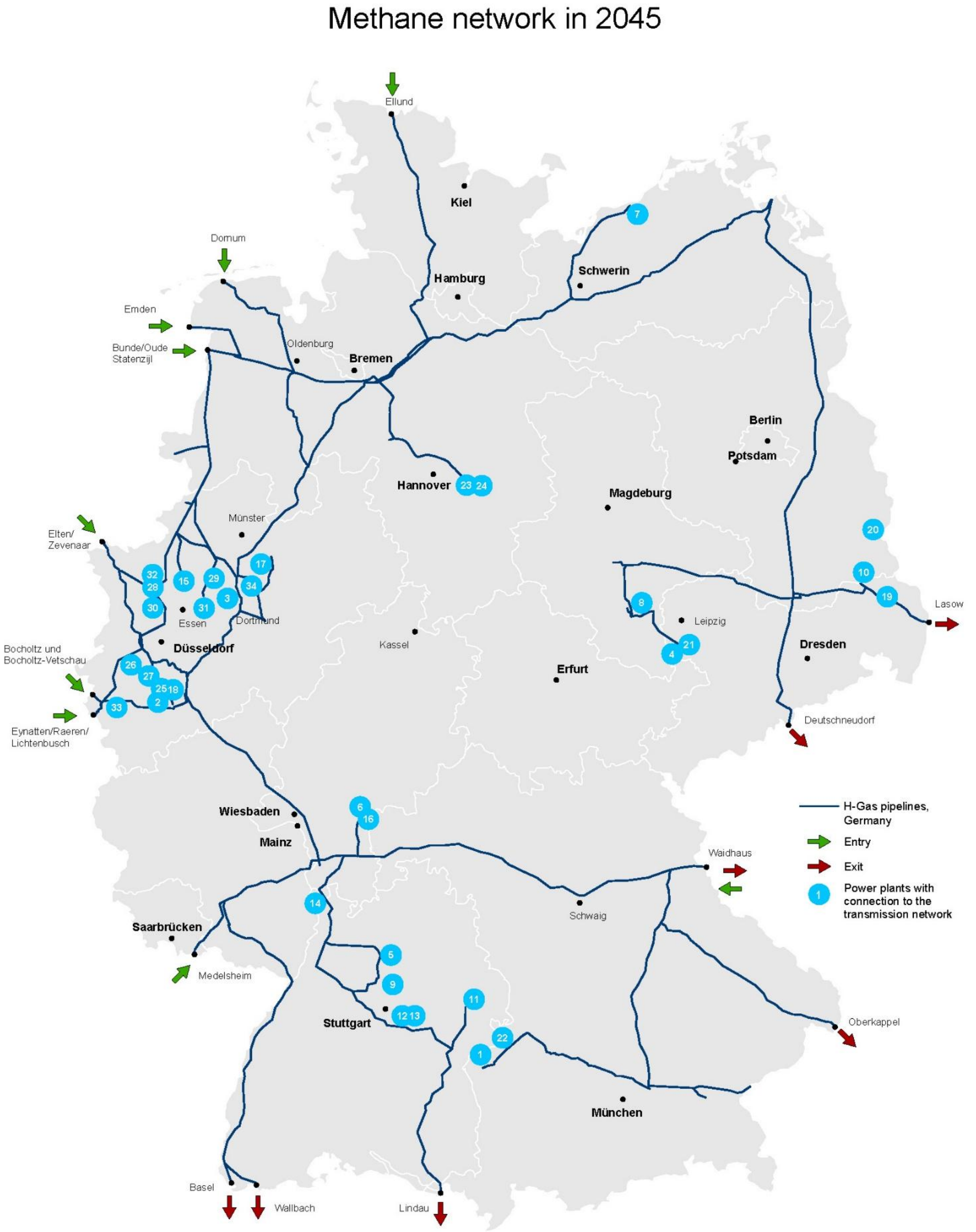
With connections to Norway, Denmark, the Netherlands, Belgium and France via cross-border IPs, several import options are available, which also ensures the resilience of the network in terms of security of supply.

Two central north-south transport connections (partly via the Czech Republic) ensure gas transportation to southern Germany to supply power plants, allow exports to neighbouring countries Switzerland, Austria, Poland and the Czech Republic, and fill storage facilities in southern Germany and Austria.

Local "storage clusters" in southern, western, northern and eastern Germany help to secure local supplies to power plants as well as exports in peak load situations, thus also contributing to the resilience of the remaining methane network.

The pipelines planned for the methane network in 2045 (scenario 3) can be found in Annex 5. The following figure is a graphical representation of the methane network in 2045. The power plants included are numbered according to **Fehler! Verweisquelle konnte nicht gefunden werden.**.

35: Methane network in 2045



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.4 Hydrogen modelling results for the year 2045

In accordance with the approved Scenario Framework, the hydrogen transmission system operators carried out detailed modelling for the three scenarios for 2045.

The input parameters for the three scenarios are set out in chapter 6.4.1 , while the results are described in chapter 6.4.2.1 et seq.

6.4.1 Input variables

Chapters **Fehler! Verweisquelle konnte nicht gefunden werden.**and 3.4 describe the fundamental approach to hydrogen modelling (including regionalisation and load cases). As part of the modelling process, the measures required to achieve the specified entry and exit capacities are identified on the basis of different load cases.

The load cases are based on the specifications issued by the BNetzA, which has defined the maximum exit capacities and minimum entry capacities for each hydrogen scenario as part of its Scenario Framework approval. These specifications are compared below for each scenario in hydrogen balances for the reference year 2045.

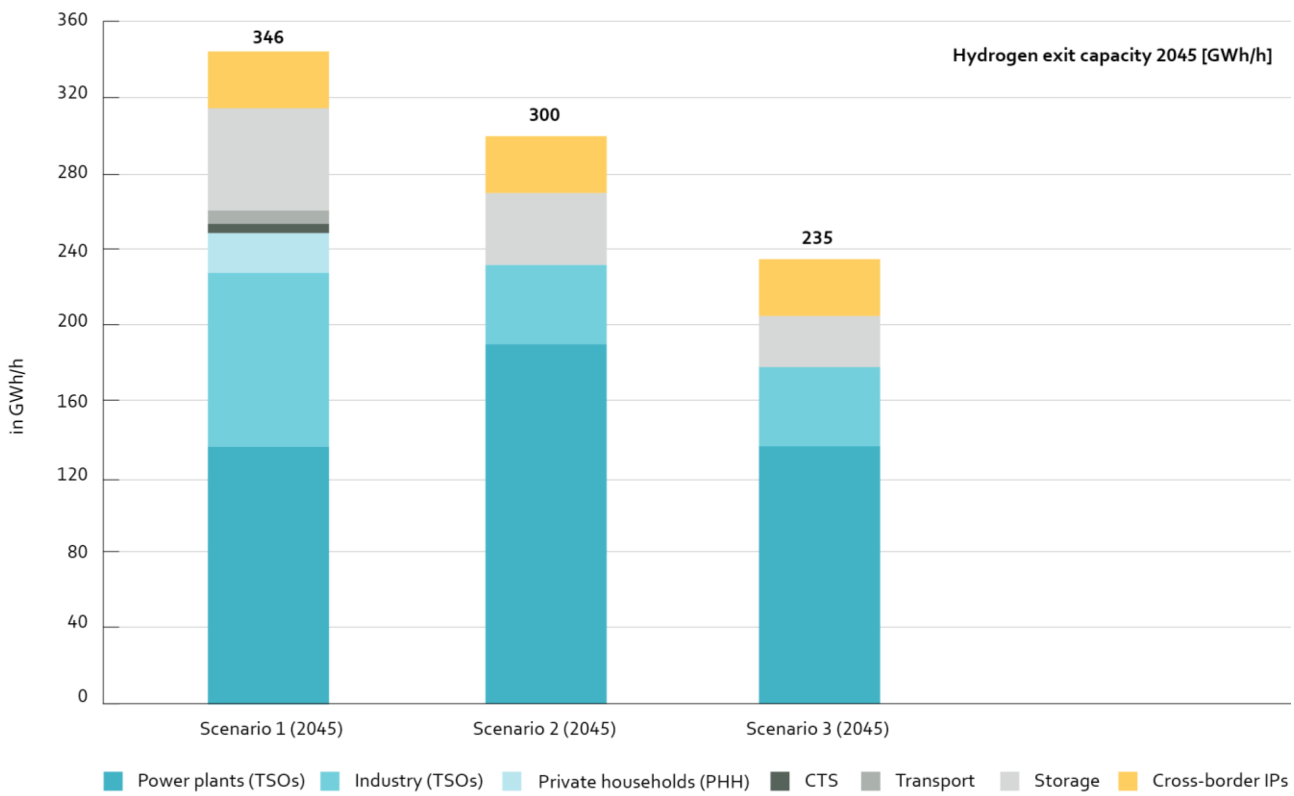
6.4.1.1 Hydrogen exit capacity demand

The hydrogen exit capacity demand is calculated as the sum of the following individual demands:

- Gas-fired power plants are included in accordance with the Scenario Framework approval (chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**). Based on the results of the market survey and our own plausibility assessments, the specified power generating capacity from the Scenario Framework approval was converted into a hydrogen connection capacity.
- The assumptions for the industry, PHH, CTS and transport sectors are taken from the Scenario Framework approval (chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**).
- The exit capacities for storage facilities were determined on the basis of the specifications set out in the BNetzA's Scenario Framework approval and the results of the market survey (chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**). The withdrawal capacities of the storage facilities assumed in the scenarios reflect the expansion of injection capacities described in chapter 6.4.1.2 .
- For the hydrogen cross-border IPs, capacities of 30 GWh/h are assumed for the modelling year 2045 in line with the Scenario Framework approval (chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**).

The following figure shows the hydrogen exit capacity for each of the scenarios for 2045.

Figure 36: Exit capacities for scenarios 1–3 (2045)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 34: Exit capacities for scenarios 1–3 (2045)

2045 hydrogen exit capacities	Scenario 1	Scenario 2	Scenario 3
	GWh/h		
Power plants	136	190	136
Industry	92	42	42
PHH	21	0	0
TCS	5	0	0
Transport	7	0	0
Cross-border IPs	30	30	30
Storage	54	38	27
Total exits	**346**	**300**	**235**

* rounded figures

Source: Coordination Office for Gas and Hydrogen Network Development Planning

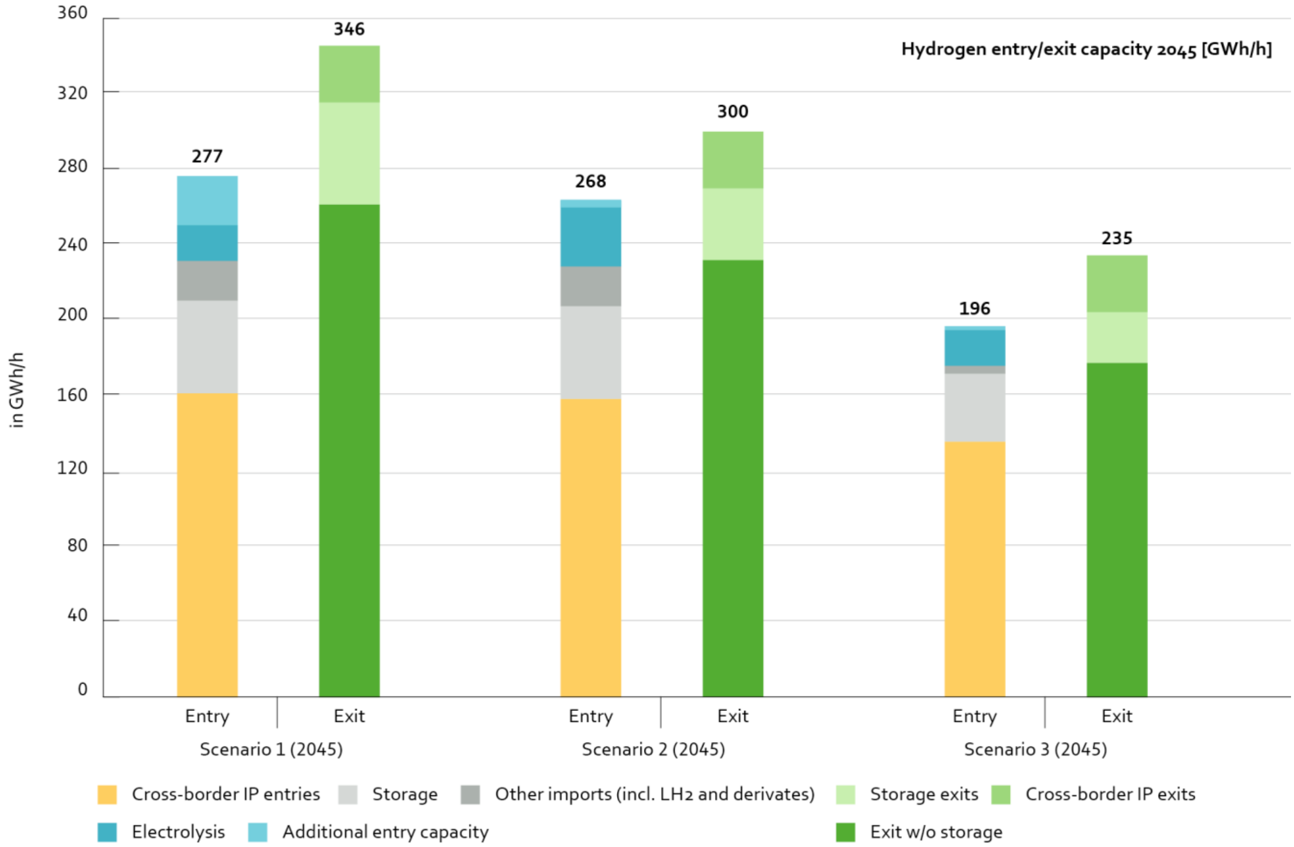
Scenario 1 exhibits the highest hydrogen demand, with hydrogen being used across all sectors. In scenario 2, only exit capacities for power plants and industry are considered, with the primary focus being on supplying power plants. Scenario 3 shows a lower hydrogen exit capacity.

6.4.1.2 Hydrogen entry capacity demand

To meet the required exit capacity, imports via cross-border IPs, withdrawals from storage facilities, other imports (including LH_2 and derivatives) and electrolysis projects are assumed. The entry capacity must cover the assumed exit capacity in every load case. As the minimum entry capacity specified in the Scenario Framework approval is insufficient for this purpose, additional potential via cross-border IPs or storage facilities has been assumed in all scenarios (chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**).

Figure 37 illustrates the export and entry capacity in the various scenarios.

Figure 37: Hydrogen entry and exits capacities for scenarios 1–3 (2045)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Table 35: Hydrogen entry and exits capacities for scenarios (2045)

2045 hydrogen entry and exit capacities	Scenario 1	Scenario 2	Scenario 3
	GWh/h		
Total entries	**277**	**268**	**196**
- thereof cross-border IPs	161	158	135
- thereof storage facilities	49	49	36
- thereof other projects (incl. LH_2 and derivatives)	21	21	4
- thereof electrolysis plants	19	35	19
- thereof additional entry capacities from storage expansion projects	26	4	2
Total exits	**346**	**300**	**235**
- thereof storage facilities	54	38	27
- thereof cross-border IPs	30	30	30
- thereof exits w/o storage and cross-border IPs	**261**	**231**	**177**

* rounded figures

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Given the very high exit capacities in 2045, all entry projects identified through the market consultation relating to storage facilities and other imports (including LH_2 and derivatives) were included in full, regardless of their reported project status. To provide the additional entries required at cross-border IPs, the transmission system operators also made selective use of potential entry capacities exceeding the base capacities at some cross-border IPs, depending on the respective scenario (Table 36).

In none of the scenarios 1–3 can the exit flows in the *dark doldrums* load case be fully compensated through the combined entries from the increased entry capacities at cross-border IPs and the full inclusion of other import and storage projects identified in the market survey. Given the limited scope for further increasing entries at cross-border IPs and from other imports, system balancing in the individual scenarios is initially achieved through a uniform over-subscription of the reported entry capacities from storage facilities across all projects. These over-subscriptions vary between the scenarios, depending on the additional entry capacity required to balance the *dark doldrums* load case. In scenario 1, an over-subscription of entry capacity from storage facilities of over 50% is required; in scenario 2, approximately 8%; and in scenario 3, just under 5%. To limit this over-subscription for storage facilities in scenario 1 to the necessary level, the Oder-Spree cross-border IP was also over-subscribed (increased to 11.1 GW) and, additionally, in the South load case, the Eynatten cross-border IP outside the entry zone was included for system balancing.

Figure 37 shows that in all scenarios, the entry capacity is greater than or at least equal to the exit capacity (w/o storage and cross-border IPs).

6.4.1.3 Entry and exit capacities at cross-border IPs

The continued integration of the German hydrogen transmission system into the wider European infrastructure plays a crucial role both in supplying the system and in enabling the distribution and handover of hydrogen to neighbouring countries. The minimum entry capacity at cross-border IPs specified in the Scenario Framework approval remains unchanged at around 59 GWh/h for the year 2045. In addition, a minimum exit capacity of around 30 GWh/h has been defined. As set out in the previous section, the entry capacities have been significantly increased by taking into account additional potential at cross-border IPs, while exit capacities have been set in accordance with the Scenario Framework approval.

The following table shows the distribution of entry and exit capacities at cross-border IPs in the three scenarios for the modelling year 2045.

Table 36: Hydrogen entry and exit capacities at cross-border IPs (2045)

Country	Cross-border IP	Scenario 1	Scenario 2	Scenario 3	Scenario 1/2	Scenario 3
		Entry [GWh/h]			Exit [GWh/h]	
Denmark	Bornholm-Lubmin	10.0	10.0	10.0	0.0	0.0
	Ellund	24.0	24.0	24.0	2.0	2.0
Norway/ UK	AquaDuctus (Offshore)	20.0	20.0	20.0	0.0	0.0
	Dornum/ Emden	10.0	10.0	10.0	0.0	0.0
Netherlands	Oude Statenzijl/ Bunde	4.0	4.0	4.0	4.0	4.0
	Vlieghuis	1.3	1.3	1.3	0.0	1.3
	Elten	3.2	3.2	3.2	3.2	3.2
	Vreden	3.2	3.2	0.0	3.2	0.0
Belgium	Eynatten	9.0	9.0	9.0	0.0	1.0
France	Medelsheim	9.0	9.0	9.0	0.0	1.0
	Freiburg	0.5	0.5	0.5	0.0	0.0
	Leidingen	0.2	0.2	0.2	0.0	0.0
	Perl	0.0	0.0	0.0	0.0	0.0
Switzerland	Wallbach	9.5	9.5	9.5	0.0	0.0
Austria	Oberkappel	0.0	0.0	0.0	4.0*	4.0*
	Überackern	6.3	6.3	6.3	2.3*	2.3*
Czech Republic**	Waidhaus	12.0	12.0	12.0	6.6	6.6
	Deutschneudorf	0.0	0.0	0.0	0.0	0.0
Poland	Oder-Spree	11.1	8.3	8.3	4.2	4.2
	Uckermark	8.0	8.0	8.0	0.8	0.8
Hydrogen imports via converted LNG terminals	Wilhelmshaven	8.3	8.3	0.0	0.0	0.0
	Stade	7.0	7.0	0.0	0.0	0.0
	Brunsbüttel	4.4	4.4	0.0	0.0	0.0
Total		161.0	158.1	135.3	30.3	30.3

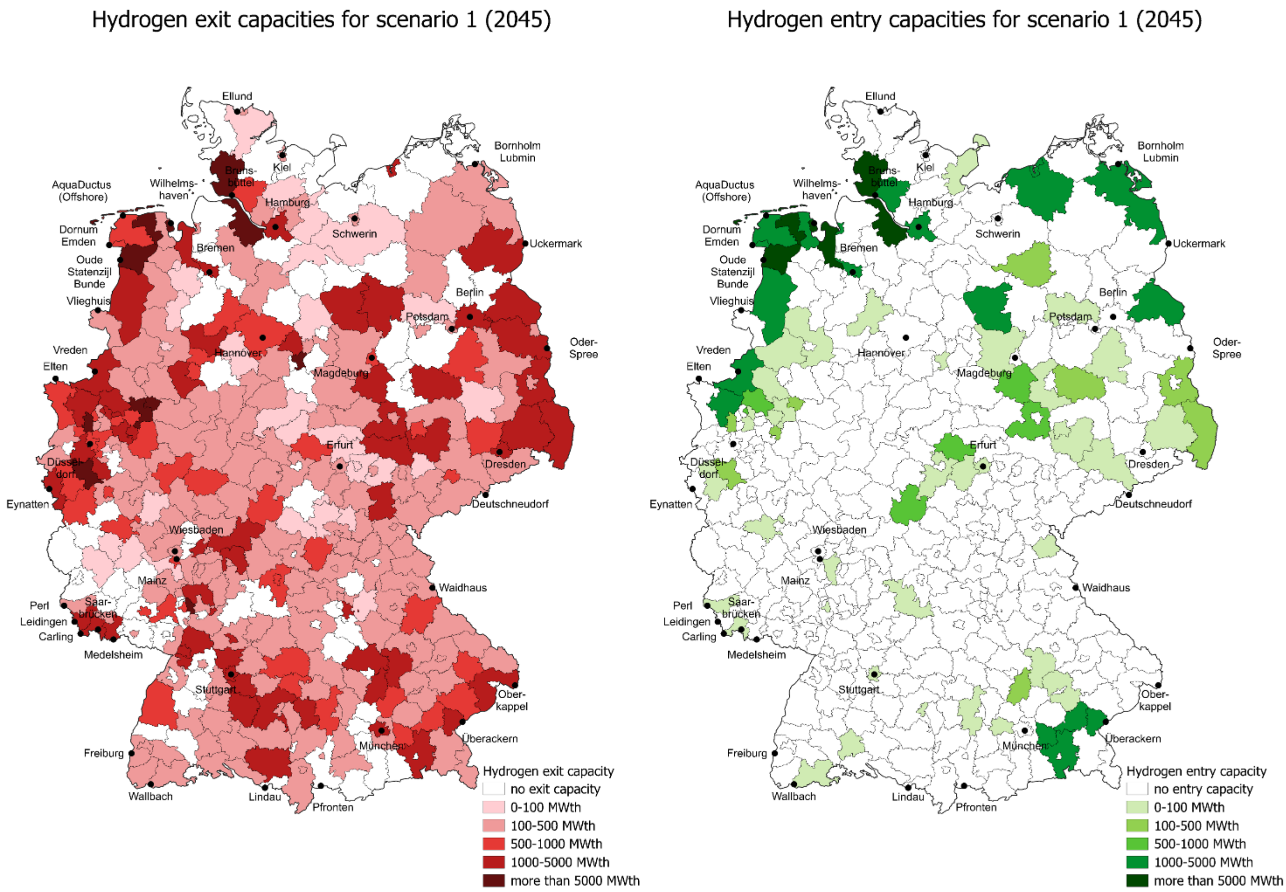
* As part of the modelling, the exit capacity of 6.3 GWh/h to Austria was allocated to the cross-border IPs at Überackern and Oberkappel. This reduces the load on the Haiming-Forchheim transmission route and, in this analysis, enables the supply of hydrogen to Austria via the MEGAL system via Rothenstadt. This will be reviewed in the next network development plan.
** Transits of up to 6.6 GWh/h were taken into account.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.4.1.4 Entry and exit capacities at district level

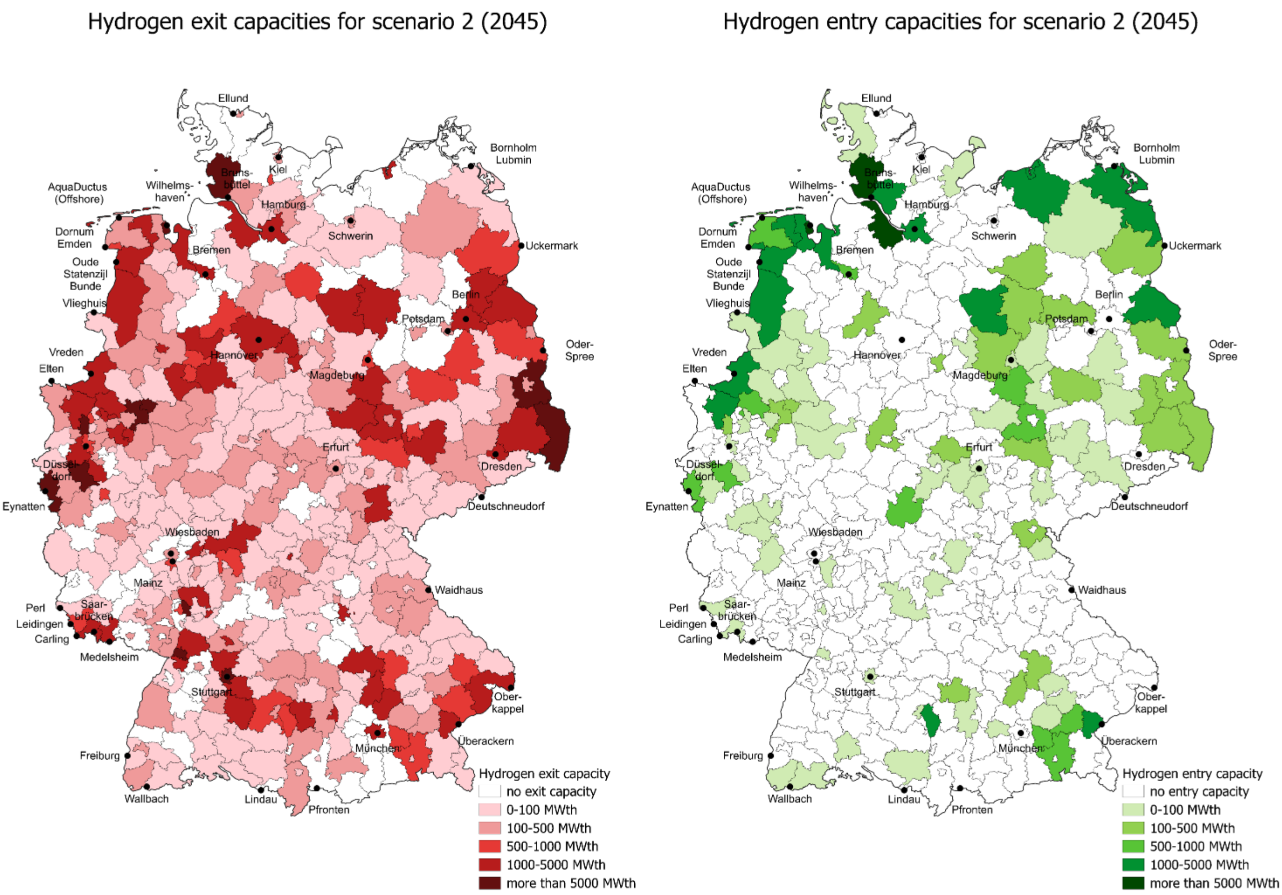
The following maps show the geographical distribution of entry and exit capacities (w/o cross-border IPs) at district level.

Figure 38: Entry and exit capacities for scenario 1 (2045) at district level, w/o cross-border IPs



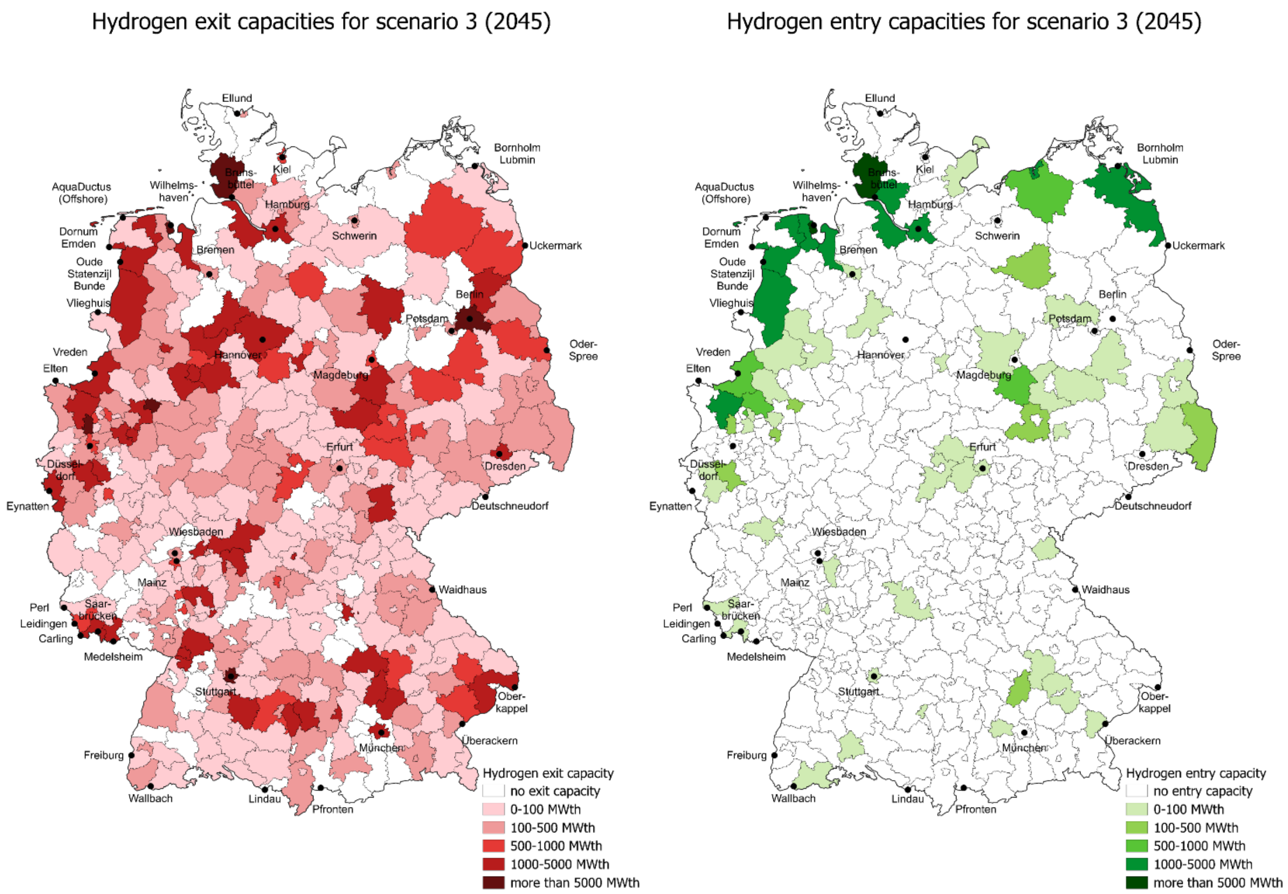
Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 39: Entry and exit capacities for scenario 2 (2045) at district level, w/o cross-border IPs



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 40: Entry and exit capacities for scenario 3 (2045) at district level, w/o cross-border IPs



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.4.2 Results

This chapter presents the results of the hydrogen modelling for the three scenarios for the year 2045 along with the starter network (chapter 4.2).

Owing to the significant increase in hydrogen demand by 2045, the need for hydrogen infrastructure is significantly higher than in 2037. At the same time, the decline in methane demand by 2045 means that this need for hydrogen infrastructure can largely be met by repurposing existing natural gas pipelines. In principle, the gas TSOs and hydrogen transmission system operators have based their 2045 modelling on the results of the 2037 modelling.

Consequently, the hydrogen infrastructure for 2045 comprises the following components:

- the hydrogen starter network (see chapter 4),
- the results of the 2037 scenario 1–3 modelling for 2037 (Gas NDP database), and
- additional measures (see Annexes 6 and 7).

The hydrogen starter network measures included have been incorporated into the 2045 modelling and form part of the hydrogen infrastructure for that year.

Almost all network expansion measures identified for 2037 are also required across all three 2045 scenarios. However, some 2037 measures are not required in all 2045 scenarios, and these measures are set out in the table below.

The additional pipeline projects required for 2045, which arise solely from the 2045 modelling, are presented in Annex 6. Annex 7 also sets out the additional compressor projects per scenario compared with 2037.

Table 37: Measures identified in the 2037 modelling that are not included in all three scenarios for 2045

NDP ID	Project title	Scenario 1 2045	Scenario 2 2045	Scenario 3 2045
H2-038-01	Achim-Heidenau pipeline incl. M&R stations	---	---	---
H2-050-01	Heidenau-Elbe Süd pipeline incl. M&R stations	---	---	---
H2-067-01	H2ercules Vreden-Gescher pipeline incl. M&R stations	x	x	---
H2-068-01	H2ercules Gescher-Werne pipeline incl. M&R stations	x	x	---
H2-069-01	H2ercules Gescher-Dorsten pipeline incl. M&R stations	x	x	---
H2-1012-01	HYMI (Edesbüttel-Bobbau) pipeline incl. M&R stations	---	--	x
H2-1017-02	Huntorf-Elsfleth 2 pipeline incl. M&R stations	---	---	x
H2-1020-02	Elsfleth-Bremerhaven pipeline incl. M&R stations	---	---	---
H2-1030-01	Luttum/Lehringen-Edesbüttel pipeline incl. M&R stations	---	---	x
H2-1042-02	Delta-Rhine-Corridor (DRC) [DN 900] pipeline incl. M&R stations	---	---	x
H2-1078-01	Böhlen-Borna pipeline incl. M&R stations	x	---	---
H2-1097-01	GETH2 Frensdorfer Bruchgraben-Frenswegen pipeline incl. M&R stations	x	x	---
H2-1103-01	Herzfelde-Alt Rüdersdorf pipeline incl. M&R stations	x	x	---
H2-1204-01	Geislingen-Hittisweiler pipeline incl. M&R stations	x	x	---
H2-1205-01	HYMI (Edesbüttel-Bobbau) pipeline incl. M&R stations	x	x	---
H2-1210-01	Luttum/Lehringen-Edesbüttel pipeline incl. M&R stations	x	x	---
H2-1211-02	Delta-Rhine-Corridor (DRC) [DN 1000] pipeline incl. M&R stations	x	x	---
H2-139-01	Borna-Thierbach pipeline incl. M&R stations	x	---	---
H2-202-01	Jettingen-Scheppach pipeline incl. M&R stations	x	---	---
H2-246-01	Alsorf-Waldhasenloh pipeline incl. M&R stations	x	---	---
H2-250-01	Voerde-Hünxe pipeline incl. M&R stations	x	x	---
H2-3026-01	Esslingen-Esslingen pipeline incl. M&R stations	---	x	x
H2-3027-01	Esslingen-Esslingen pipeline incl. M&R stations	---	x	x
H2-3028-01	Esslingen-Altbach pipeline incl. M&R stations, incl. underwater crossing	---	x	x
H2-3029-01	**Altbach-Altbach pipeline incl. M&R stations**	---	x	x

Source: Coordination Office for Gas and Hydrogen Network Development Planning

The core network measures known as the Achim-Heidenau pipeline with M&R stations (H2-038-01) and the Heidenau-Elbe Süd pipeline with M&R stations (H2-050-01), are included in the hydrogen network model for 2037. For 2045, these two pipelines have been included in the methane network at reduced diameters (DN450 and DN600) because, contrary to 2037, the Achim-Elbe Süd pipeline (DN1400 (NDP ID 767-03) will be available in 2045 as an additional pipeline for conversion to hydrogen, which means there will be no need for a newly built hydrogen pipeline along the same route section (cf. No. 1 in Annex 6a).

For the hydrogen transmission system operators, the hydrogen modelling for 2045 provides an important outlook for the long-term development of the hydrogen infrastructure. However, due to the long-term nature of the outlook, the hydrogen modelling results for the year 2045, are not yet relevant for the specific network expansion proposal, partly because investment decisions for this long period do not have to be made just yet.

The results of the modelling for scenarios 1 and 2 show only minor differences in pipeline infrastructure. The main difference is the compressor capacity required. Due to the lower demand for hydrogen, the transport infrastructure in scenario 3 is considerably smaller than in scenarios 1 and 2, both in terms of pipeline infrastructure and compressor capacity.

6.4.2.1 Scenario 1 (2045)

The results for scenario 1 (2045) are presented in Table 38 below and in Figure 41.

Table 38: Hydrogen modelling results for scenario 1 (2045) and the hydrogen starter network

Scenario 1 results for 2045*	**Starter network**	**By 2037**	**2038 to 2045**	**Starter network and result for scenario 1 2045**
Technical parameters				
Compressor capacity [MW]	6	761	2,767	3,534
Pipelines [km]	2,201	8,229	7,820	18,249
- thereof repurposed pipelines [km]	1,599	4,727	6,534	12,859
- thereof new pipelines [km]	602	3,316	1,286	5,204
- thereof new pipelines (offshore) [km]	0.0	186	0.0	186
- For information: Czech German Hydrogen Interconnector (CGHI)** [km]	168			
Total investments [EUR bn]	**4.0**	**25.8**	**26.3**	**56.1**
Compressor stations	0.1	5.4	16.8	22.3
Pipelines (incl. M&R station costs)	4.0	20.3	9.5	33.8
- thereof repurposed pipelines	1.1	3.2	3.2	7.6
- thereof new pipelines	2.9	15.2	6.3	24.4
- thereof new pipelines (offshore)	0.0	1.9	0.0	1.9

* rounded figures

** CGHI was taken into account for the modelling, but is not part of the German hydrogen network.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 41: Hydrogen modelling results for scenario 1 (2045)

Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.4.2.2 Scenario 2 (2045)

The results for scenario 2 (2045) are presented in Table 39 below and in Figure 42.

Table 39: Hydrogen modelling results for scenario 2 (2045) and the hydrogen starter network

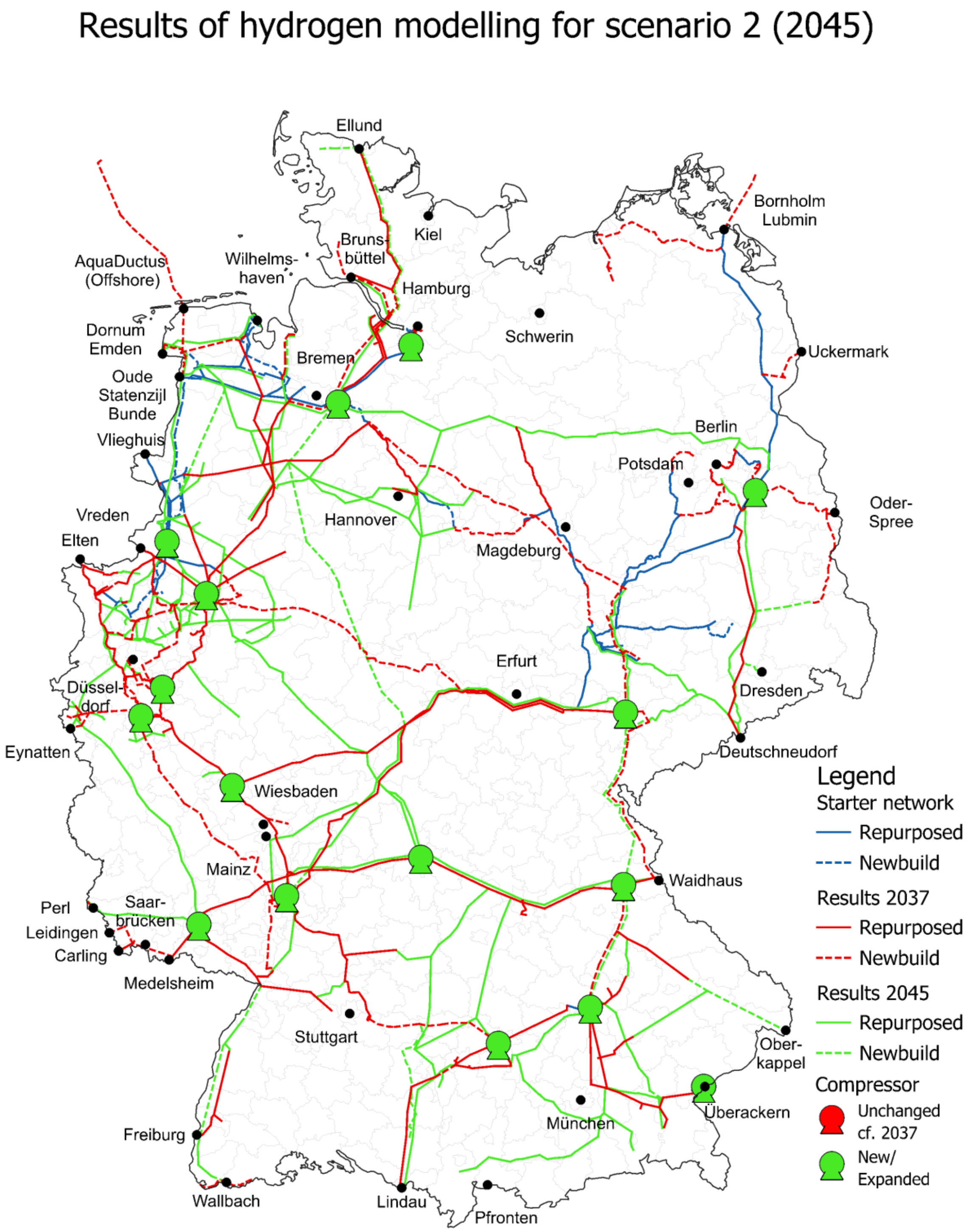
Scenario 2 results for 2045*	Starter network	By 2037	2038 bis 2045	Starter network and result for scenario 2 2045
Technical parameters				
Compressor capacity [MW]	6	520	2,027	2,553
Pipelines [km]	2,201	7,998	8,235	18,434
- thereof repurposed pipelines [km]	1,599	4,514	6,910	13,022
- thereof new pipelines [km]	602	3,298	1,326	5,226
- thereof new pipelines (offshore) [km]	0	186	0	186
- For information: Czech German Hydrogen Interconnector (CGHI)** [km]	168			
Total investments [EUR bn]	**4.0**	**24.1**	**21.8**	**49.9**
Compressor stations	0.1	4.0	11.8	15.9
Pipelines (incl. M&R station costs)	4.0	20.1	9.9	34.0
- thereof repurposed pipelines	1.1	3.1	3.4	7.6
- thereof new pipelines	2.9	15.1	6.5	24.5
- thereof new pipelines (offshore)	0.0	1.9	0.0	1.9

* rounded figures

** CGHI was taken into account for the modelling, but is not part of the German hydrogen network.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 42: Hydrogen modelling results for scenario 2 (2045)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.4.2.3 Scenario 3 (2045)

The results for scenario 3 (2045) are presented in Table 40 below and in Figure 43.

Table 40: Hydrogen modelling results for scenario 3 (2045) and the hydrogen starter network

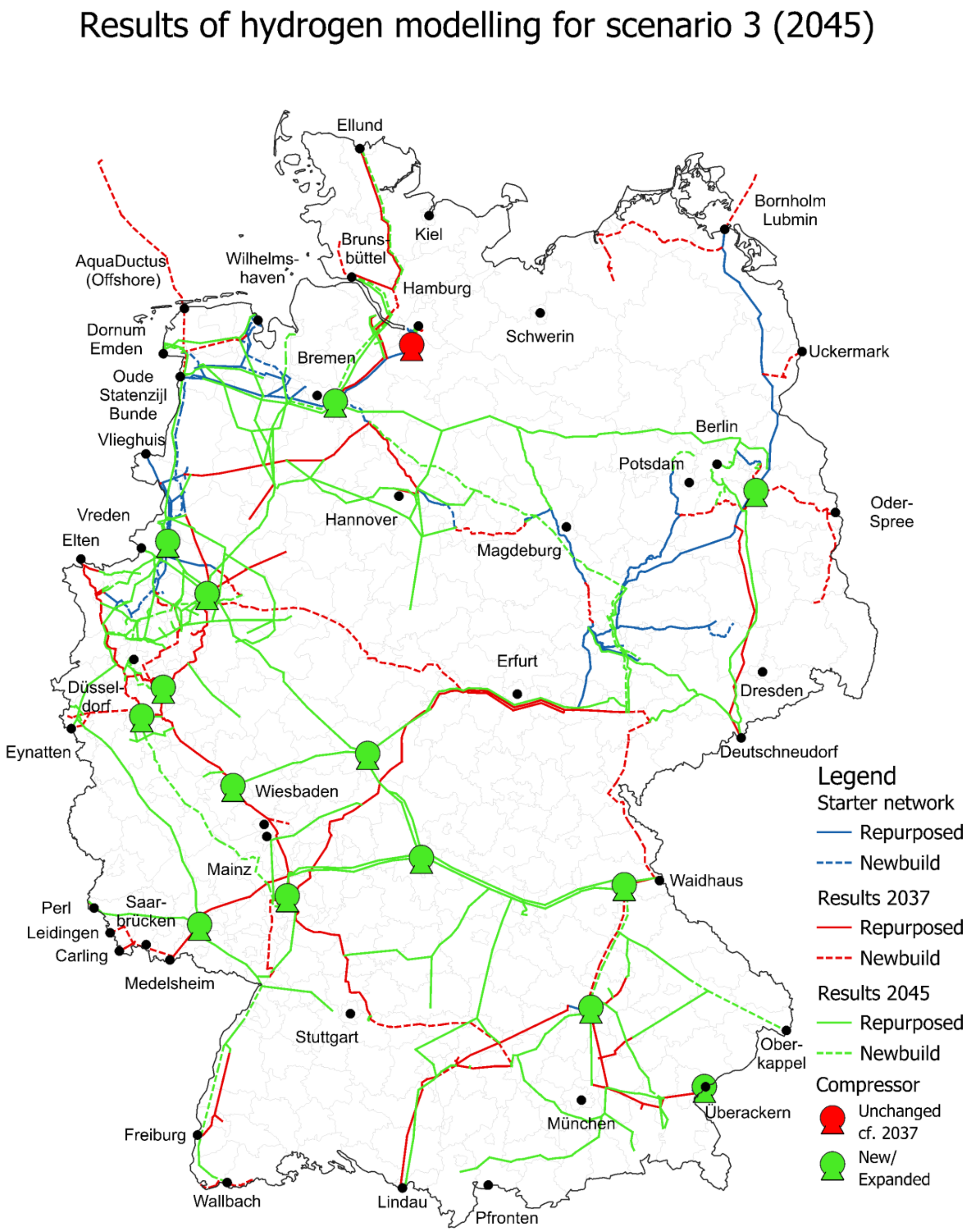
Scenario 3 results for 2045*	**Starter network**	**By 2037**	**2038 to 2045**	**Starter network and result for scenario 3 2045**
Technical parameters				
Compressor capacity [MW]	6	8	1,804	1,818
Pipelines [km]	2.201	5.232	9.844	17.277
- thereof repurposed pipelines [km]	1.599	2.956	8.168	12.723
- thereof new pipelines [km]	602	2,091	1,676	4,368
- thereof new pipelines (offshore) [km]	0	186	0	186
- For information: Czech German Hydrogen Interconnector (CGHI)** [km]	168			
Total investments [€ bn]	**4.0**	**13.1**	**22.9**	**40.1**
Compressor stations	0.1	0.1	10.7	10.9
Pipelines (incl. M&R station costs)	4.0	13.0	12.2	29.2
- thereof repurposed pipelines	1.1	2.0	4.4	7.5
- thereof new pipelines	2.9	9.1	7.8	19.8
- thereof new pipelines (offshore)	0.0	1.9	0.0	1.9

* rounded figures

** CGHI was taken into account for the modelling, but is not part of the German hydrogen network.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 43: Hydrogen modelling results for scenario 3 (2045)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.5 NewCap modelling results – MBIs and network expansion

6.5.1 NewCap capacity model

The formation of the THE market area coincided with the introduction of market-based instruments (MBIs) to ensure the free allocation of the required capacity, with the demand for freely allocable capacity (FAC) corresponding to the sufficient level in accordance with to chapter 3.3.3 .

For the NewCap capacity model, the fluid dynamics modelling in the Gas and Hydrogen Network Development Plan 2025 is supplemented by additional statistically based balancing models. The aim of the model is to identify an economic optimum between network expansion and the use of MBIs. The market-based instruments available include exchange-based products (between congestion zones), third-party network access, and VIP wheeling (via adjacent foreign networks).

A more detailed description of the methodology and the underlying assumptions is provided in the Gas Network Development Plan 2020–2030 (chapters 3.4.2 and 7.6.1).

The NewCap capacity model is reviewed regularly in light of developments in the gas market. In particular, the cessation of Russian imports since the start of the war in Ukraine, as well as updated assumptions regarding the development of the methane market and the partial transition to hydrogen, have led to adjustments which relate in particular to the statistical approach, the formation of congestion zones, the design of the NewCap scenarios, and the extent of market shifts to be taken into account. The adjustments are explained below.

Statistical approach

The network usage scenarios in this Gas and Hydrogen Network Development Plan 2025 are based on the period from 1 April 2023 to 31 March 2025.

Although shortening the period from 36 months, as envisaged in the Gas Network Development Plan 2020–2030, to 24 months reduces the statistical significance, the transmission system operators do not yet consider the period prior to 1 April 2023 – when the LNG market in Germany was still developing only gradually – to be representative of future demand.

The MBI modelling is carried out for the gas marketing years 2027/2028 (reference year), 2029/2030 (scenario 4) and 2036/2037 (scenario 3).

Modelling for the year 2044/2045 has been omitted due to low methane demand. Similarly, modelling for scenarios 1 and 2 has not been undertaken, as both consumption and required capacity are lower than in scenario 3. Scenario 3 therefore represents the scenario with the highest expected deployment of MBIs.

Congestion zones

At present, the exchange product (see Gas Network Development Plan 2020–2030, Chapter 3.4.2) is used between the two congestion zones THE North and THE South, which correspond to the network areas of the former GASPOOL and NCG market areas.

However, the fluid dynamics modelling in the present Gas and Hydrogen Network Development Plan 2025 has identified a potential new bottleneck in the THE South zone. This occurs only in scenario 4 (2030), however, so the expansion of the Scheidt compressor station identified for this purpose is not part of the network expansion proposal.

Given the number of active shippers, available storage sites and cross-border IPs, there should still be sufficient liquidity to procure exchange products even in the event of a hypothetical division of THE South into two sub-zones.

The NewCap model therefore formally assumes the three congestion zones THE Northeast (formerly THE North), THE Northwest and THE Southwest (division of THE South) in order to assess the potential impact on future MBI deployment. This assumption does not, however, imply any commitment to an actual future restructuring of congestion zones.

NewCap scenarios

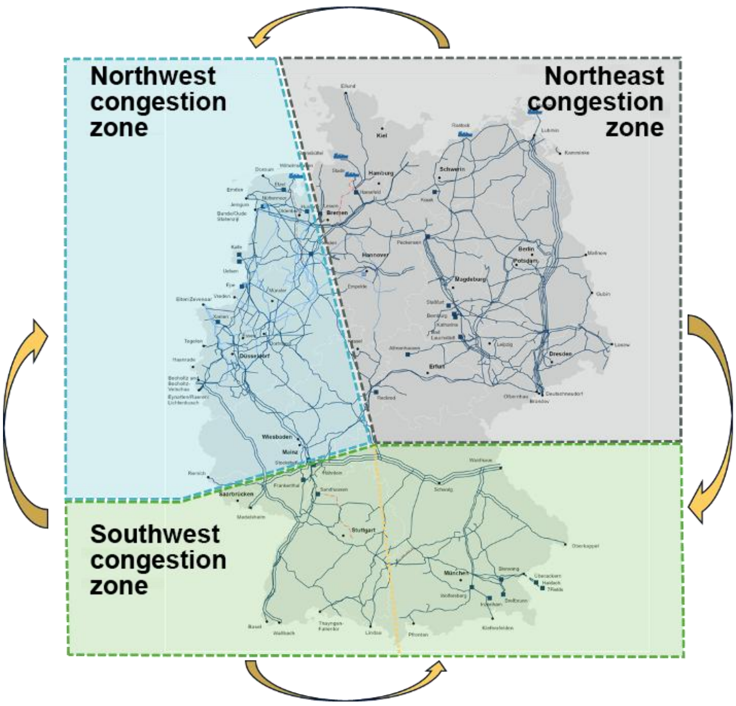
For each year under consideration, a baseline scenario is used as the starting point, with variations applied to flows at cross-border IPs and LNG entry points to examine both the redistribution of gas flows between corridors and potential increases in transit volumes.

The Gas Network Development Plan 2020–2030 was based on the assumption that differences in prices for gas from Russia, Norway and LNG would lead to a shift in gas flows via the cross-border IPs served by these sources.

Following the cessation of Russian imports, this approach had to be revised. In addition, experience has shown that, particularly for LNG transport, it is not only the commodity price but also the transport route that influences the utilisation of the import point.

Accordingly, the NewCap scenario development adopts a regional approach, varying flows in both the west–east and north–south directions (see Figure 44).

Figure 44: NewCap – Schematic representation of congestion zones and flow variations



Source: Coordination Office for Gas and Hydrogen Network Development Planning

The other assumptions regarding the percentage variations in redistribution and transit scenarios remain unchanged.

The maximum number of NewCap scenarios to be analysed per year amounts to 41 according to the approach described. Although this represents a reduction compared with the Gas Network Development Plan 2020–2030, it remains more than sufficient with approximately 30,000 individual load cases modelled per year.

Market shift

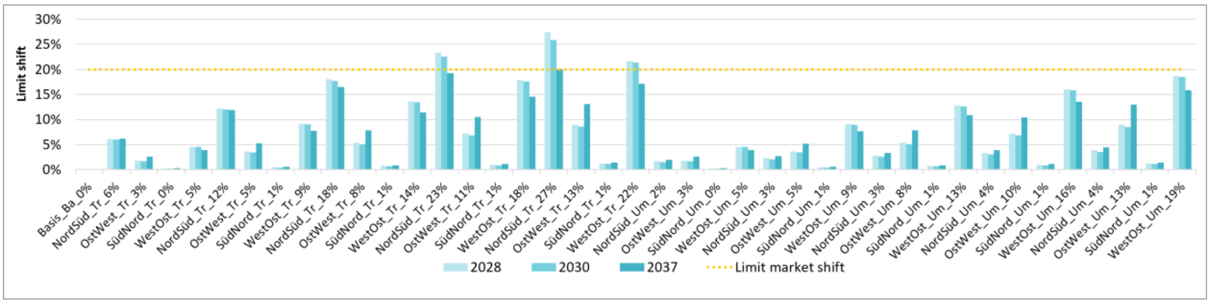
For each NewCap scenario and year under review, the relative market shift continues to be examined; i.e. the ratio of the absolute annual change in the respective import zone (compared with the base scenario) to assumed domestic annual consumption.

In the Gas Network Development Plan 2020–2030, NewCap scenarios were included in the analysis up to a 10% market shift in order to limit the influence of unrealistically high variations on MBI demand.

In the light of recent changes in the gas market, additional NewCap scenarios have since been included in the evaluations. The present analysis therefore considers all NewCap scenarios with a market shift of up to 20% in each year.

Of the 41 scenarios, three show a market shift greater than 20% (see Figure 45). This leaves 38 scenarios with just under 28,000 load cases considered per year:

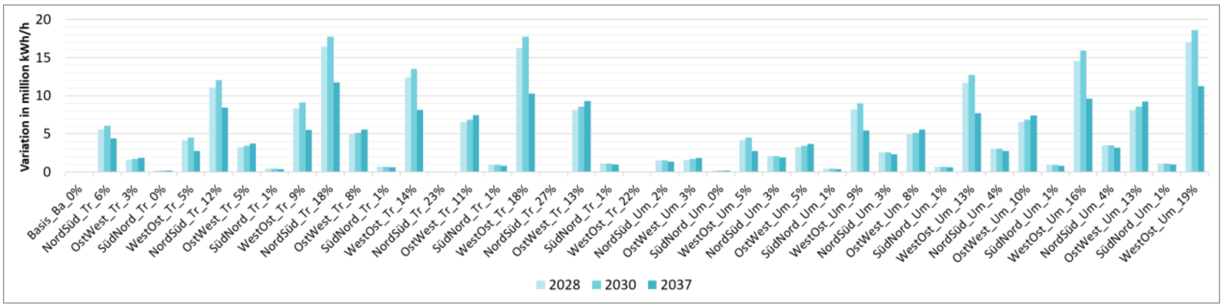
Figure 45: Average market shift per scenario



Source: Coordination Office for Gas and Hydrogen Network Development Planning

The average variation (i.e. the absolute daily change compared to the baseline scenario) is, in some cases, even higher than the values reported in the Gas Network Development Plan 2020–2030 (see Figure 46):

Figure 46: Average variation per scenario in million kWh/h



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Price assumptions for market-based instruments

The assumptions regarding specific prices for the use of market-based instruments are consistent with the approach set out in the 2020–2030 Gas Network Development Plan.

For third-party network use and VIP wheeling, the transmission charges of neighbouring foreign network operators are applied.

The cost assumptions for the exchange product are based on an analysis of historical price differentials for the purchase and sale of balancing gas in the H-gas network area. The modelling uses quarterly averages of the days on which system balancing actions were taken in opposite directions and on which the price differential greater than zero.

6.5.2 Result of the MBI calculation ("base variant")

In the base variant, a calculation was performed for the gas market years 2027/2028 (reference year), 2029/2030 (scenario 4) and 2036/2037 (scenario 3). The infrastructure used was the starter network plus the measures from the network expansion proposal for methane in the 2025 Gas and Hydrogen Network Development Plan. The measures contained in the network expansion proposal are local in nature and cannot therefore be replaced by MBIs.

Local bottlenecks

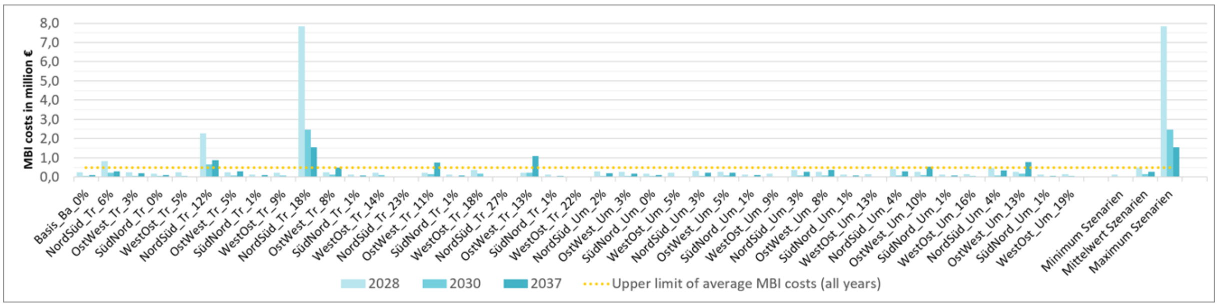
The NewCap models do not identify any statistically significant local bottlenecks within any of the congestion zones under consideration.

Need for market-based instruments

The need for market-based instruments initially declines over the period from the 2027/2028 and 2029/2030 gas market years, before increasing slightly by 2036/2037.

This is primarily driven by changes in consumption (which initially increases due to L-gas to H-gas conversion and demand from new power plants up to 2029/ 2030, before declining as a result of energy efficiency measures and the transition to hydrogen) as well as the distribution of point-specific entry capacity requirements for a sufficient level of FACs. The annual MBI costs per scenario are shown in the following figure.

Figure 47: Costs of market-based instruments in million EUR/year



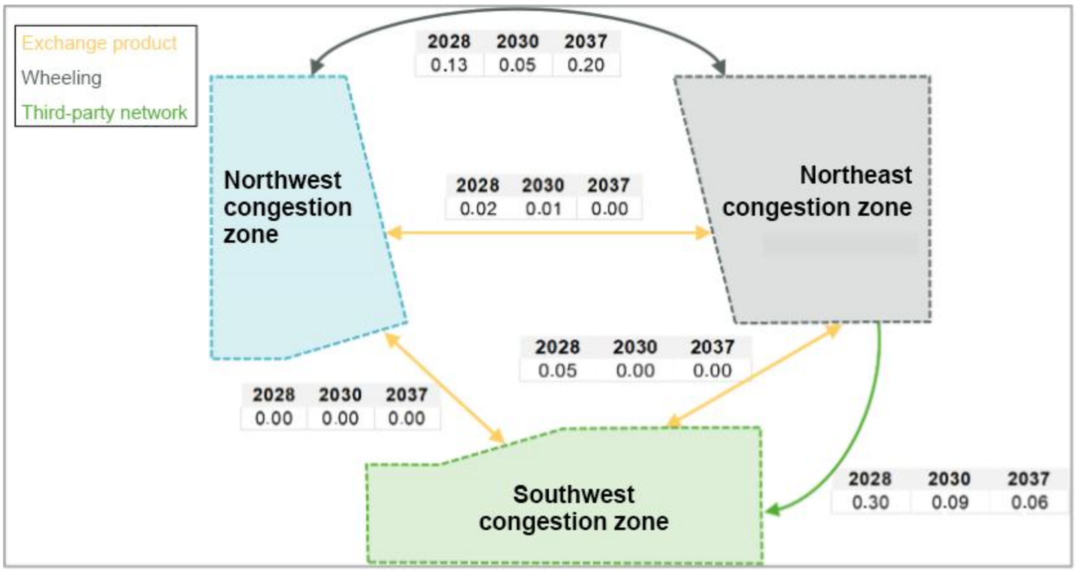
Source: Coordination Office for Gas and Hydrogen Network Development Planning

On average across the NewCap scenarios, the calculations show MBI costs of less than €0.5 million in all three years under consideration.

MBI costs exceeding €2.5 million per year occur only in two outlier scenarios and only in 2027/2028. A network expansion to resolve the observed bottlenecks in 2027/2028 would not be feasible in terms of timing. Furthermore, such an expansion would not be sustainable, as MBI costs fall in subsequent years.

The following figure provides a schematic breakdown of MBI costs (average of the NewCap scenarios considered, in million euros per year) across the individual products. Operationally, deployment is cost-optimised based on daily specific prices, so the distribution may vary.

Figure 48: Breakdown of average MBI costs by product in million EUR/year



Source: Coordination Office for Gas and Hydrogen Network Development Planning

Taking the three zones described above into account, no congestion is observed within the existing THE South zone. However, without a subdivision of THE South zone, congestion in north-south transmission may arise in certain NewCap scenarios. This is driven by the increase in LNG capacities in northeastern Germany. A redefinition of the congestion zones will therefore only be required once the onshore terminals have entered operation, meaning that a further review can be undertaken as part of the subsequent network development plan process.

Assessment: Comparison of MBI and network expansion

The following table shows the development of costs for market-based instruments for both the minimum and maximum NewCap scenarios, as well as for the average of the NewCap scenarios considered in In the base variant, a calculation was performed for the gas market years 2027/2028 (reference year), 2029/2030 (scenario 4) and 2036/2037 (scenario 3). The infrastructure used was the starter network plus the measures from the network expansion proposal for methane in the 2025 Gas and Hydrogen Network Development Plan. The measures contained in the network expansion proposal are local in nature and cannot therefore be replaced by MBIs.

Local bottlenecks

The NewCap models do not identify any statistically significant local bottlenecks within any of the congestion zones under consideration.

Need for market-based instruments

The need for market-based instruments initially declines over the period from the 2027/2028 and 2029/2030 gas market years, before increasing slightly by 2036/2037.

This is primarily driven by changes in consumption (which initially increases due to L-gas to H-gas conversion and demand from new power plants up to 2029/ 2030, before declining as a result of energy efficiency measures and the transition to hydrogen) as well as the distribution of point-specific entry capacity requirements for a sufficient level of FACs. The annual MBI costs per scenario are shown in the following figure.

Figure 47.

Table 41: Trend in the cost of market-based instruments in millions EUR/Jahr

Cost of market-based instruments in million EUR /year	2027/2028	2029/2030	2036/2037
Max. scenario	7.8	2.5	1.5
Av. scenarios	0.5	0.2	0.3
Min. scenario	0.1	< 0.1	< 0.1

Source: Coordination Office for Gas and Hydrogen Network Development Planning

The demand for market-based instruments depends not only on the utilisation pattern within Germany but also on future import and export volumes. Demand therefore varies significantly across the NewCap scenarios under consideration. The results of the NewCap modelling can thus only indicate a range of costs, with the minimum cost potentially being zero.

Consequently, the cost trajectory of the maximum NewCap scenario alone cannot be used to assess whether additional network expansion would be justified for reducing MBI costs. Whilst market-based instruments can be procured in the short term and thus deployed as required, investments lead to a long-term increase in network costs, even if the future NewCap scenarios require less replacement capacity than assumed in the maximum NewCap scenario based on the available data.

By way of comparison, the average MBI cost is significantly lower than the annual costs of an M&R station with a capacity of 1 million Nm^3/h and commissioning in 2027, which amount to over 2 million euros per year.

The calculated MBI costs are therefore so low that, from an economic perspective, no additional expansion measures beyond those set out in the proposed network development plan are justified. As mentioned above, the measures specified in the network expansion proposal cannot be substituted by MBIs.

6.5.3 Result of the MBI calculation – assessment of additional natural gas conversions

The low demand for MBIs in the base variant may raise the question of whether the scope of the new hydrogen infrastructure could be reduced by repurposing further methane infrastructure and making greater use of MBIs.

To assess this question, the transmission system operators have applied the following criteria:

(a) The hydrogen measure is not part of the start-up network.

(b) There is methane infrastructure that could replace the measure under (a). For example, methane infrastructure of a regional nature may not be sufficient to meet the transport requirements addressed by the hydrogen measure.

(c) Following additional methane conversion in line with (b), all customer demand for methane and the required capacity (sufficient level) can in principle continue to be met – subject to the use of MBIs in the event of a congestion. If this is not guaranteed, the methane infrastructure will continue to be needed for methane.

(d) An appropriate market-based instrument (exchange product, third-party network access or VIP wheeling) is available with sufficient liquidity to resolve the resulting congestion in the methane network.

(e) The additional cost of MBI is lower than the difference between new hydrogen infrastructure and methane conversion.

To assess criteria (a) to (c), a comprehensive fluid dynamics modelling exercise across all hydrogen and methane scenarios is required, followed by a NewCap assessment.

The modelling must be carried out not only for each measure individually, but also for all possible combinations of measures. As a result, the effort involved increases exponentially with the number of measures identified.

In view of this exponentially increasing effort, only a limited number of selected measures can be assessed, focusing on those identified through expert judgement as offering the greatest potential.

However, following review by the gas TSOs and hydrogen transmission system operators, no hydrogen measures outside the start-up network were identified in this Gas and Hydrogen Network Development Plan 2025 for which both an alternative methane infrastructure and sufficiently liquid market-based instruments might be available. Consequently, no additional MBI calculation is required in this context.

The list of reviewed new hydrogen infrastructure projects, including the respective justifications, is set out in Annex 10.

Network Expansion Proposal 7

7 Network Expansion Proposal

This chapter explains how network expansion measures were identified on the basis of the Scenario Framework 2025–2037/2045 approved by the Federal Network Agency (BNetzA) and how the network expansion proposal for the methane and hydrogen networks was subsequently developed. The individual expansion measures were derived from the various scenarios, whereby some of the measures from the modelling results were combined with each other. This approach takes into account the continuing uncertainties regarding the actual development of methane and hydrogen demand and the temporal and spatial ramp-up of the hydrogen market. At the same time, the gas TSOs and hydrogen transmission system operators are thus meeting energy and climate policy objectives.

The modelling results for hydrogen based on scenarios 1 and 2 each result in an expansion that is larger than the already approved hydrogen core network. This is due to the higher transportation requirements resulting from stronger demand growth. Meeting these transportation requirements requires additional network expansion measures and adjustments to technical parameters of approved core network measures, such as increasing pipeline diameters or changing compressor capacities.

In contrast, the modelling results from scenario 3 show an expansion that is smaller than the approved hydrogen core network. This scenario is based on rather conservative assumptions about the ramp-up of the hydrogen market and the resulting transportation requirements.

It must also be noted that the scenarios considered represent different development paths. At present, it is not yet possible to predict conclusively which of the scenarios is most likely to occur. Therefore, it is not appropriate at this stage for the network expansion proposal to be based solely on a single scenario from the gas TSOs' perspective.

It is also worth pointing out that no decision is currently required on additional hydrogen projects for periods from 2037 onwards, nor on the possible discontinuation of individual projects of the approved hydrogen core network. The current planning horizon and the continuing uncertainty about the future development of the hydrogen market seem to suggest that it is too early to decide on more extensive or reduced expansion plans. In anticipation of a continuously improving information base, and especially of increasingly reliable data on the hydrogen ramp-up, future network development plans offer sufficient opportunity to do so.

Against this background, a scenario-spanning, criteria-based approach was chosen to develop the network expansion proposal. The aim of this approach is to propose only those expansion measures that are considered necessary or structurally sensible. This takes account of the need not to define premature and thus potentially unnecessary network expansion measures, but rather to focus on the further development of the hydrogen ramp-up and to align future decisions with this development.

The core network creates a reliable framework for the market ramp-up by giving potential market players early assurance that the necessary transportation capacities for hydrogen will be provided. The network expansion proposal is therefore balanced between upfront investment and concrete demand orientation: the already approved core network creates a robust starting point for the development of a hydrogen economy, while further scenario-based expansion steps not based on concrete, already established demand requirements are disregarded.

The network expansion proposal therefore represents a robust and adaptable development step within the continuous network development planning process. It enables future adjustments to be made in line with actual market developments and the findings of future network development plans.

The network expansion measures were selected and prioritised on the basis of clearly defined criteria. The criteria are not only used to identify additional expansion requirements but also take into account the statutory mandate under Section 28q (8) of the German Energy Industry Act (EnWG) to systematically review and critically examine the approved hydrogen core network as part of network development planning.

For some core network measures that have already been approved, adjustments have been made to the planned commissioning dates and the dimensioning. The reasons for these adjustments are varied and cannot always be attributed to a single cause. The adjustments have been taken into account in the current network expansion proposal.

The cross-scenario criteria also ensure that the methane network expansion is designed in a way that is appropriate and meets actual needs. In particular, in view of the expected decline in methane demand, care is taken to ensure that no network expansion measures are planned that exceed actual demand. The expansion proposal for the methane network is therefore limited to those measures that are necessary to ensure safe and efficient network operation.

7.1 Criteria for the methane network expansion proposal

The following section explains the six criteria used to determine the methane network expansion proposal, which were developed for the modelling years 2030 and 2037. These criteria were applied to each network expansion measure. The results can be found in Appendix 2.

Criteria 1–3 are not related to hydrogen conversion measures, while criteria 4–5 relate to natural gas-reinforcing measures for the hydrogen transition.

CH_4(1): Measures that result from the modelling throughout scenarios 1–4 in 2030 and 2037 have been included in the network expansion proposal.

CH_4(2): Measures that do not result from the modelling in all scenarios 1–4 in 2030 and 2037 but meet the needs of power plants and industry have been included in the network expansion proposal.

CH_4(3): Measures that do not result from the modelling in all scenarios 1–4 in 2030 and 2037 and do not meet the needs of power plants and industry have not been included in the network expansion proposal.

CH_4(4): Natural gas-reinforcing measures have been included in the network expansion proposal if the associated hydrogen conversion measures have also been included in the network expansion proposal.

CH_4(5): Natural gas-reinforcing measures have not been included in the network expansion proposal if the associated hydrogen conversion measures are not included in the network expansion proposal.

CH_4(6): Measures that are not the result of modelling in any of scenarios 1–4 in 2030 and 2037 have not been included in the network expansion proposal.

7.2 Methane network expansion proposal

The network expansion proposal for methane has been developed from an economic and climate-protection perspective. Measures for industry and power plants are to be executed provided that the customer makes a binding commitment to take methane by reserving transportation capacity or committing to an implementation roadmap and concluding an agreement on a long-term booking. The network expansion proposal includes all measures required in all three scenarios for 2037. However, the need for these measures will be reviewed in future network development plans. The execution of natural gas-reinforcing measures will also be closely linked to the corresponding conversion measures for hydrogen.

The methane network expansion proposal is presented in Table 42 and Figure Figure 49 and takes account of the above criteria. The relevant methane projects are set out in Annex 8.

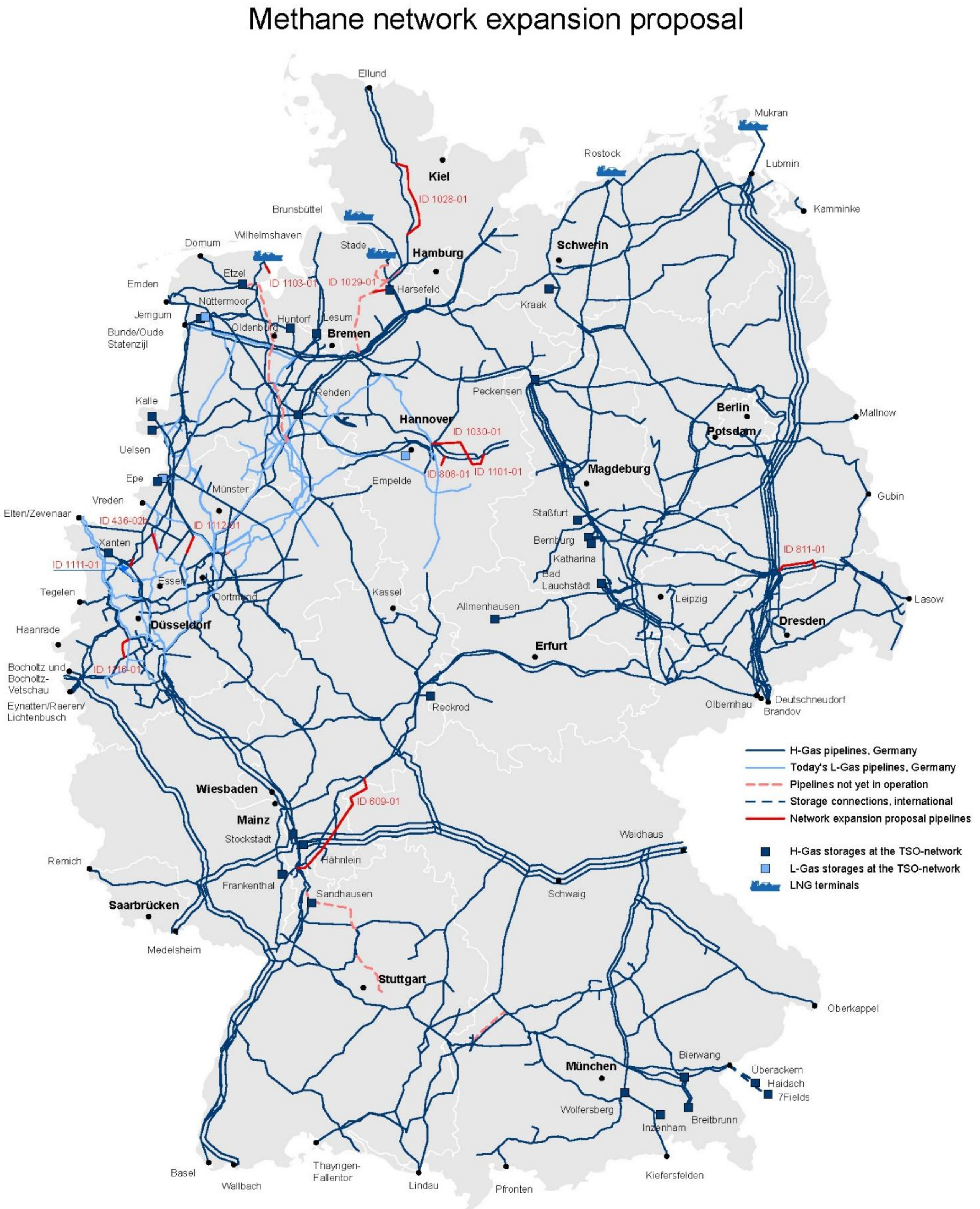
Table 42: Methane network expansion proposal

Results of methane network expansion proposal	
Technical parameters	
Pipelines [km]	672
Compressor capacity [MW]	0
Total investment [billion euros]	**2.9**
- of which network expansion measures from NDP 2022	1.0
- of which natural gas-reinforcing measures from NDP 2022 and core network	1.4
- of which new network expansion measures for power plants and industry	0.4
- of which new natural gas-reinforcing measures	0.2

* rounded figures

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 49: Methane network expansion proposal



Source: Coordination Office for Gas and Hydrogen Network Development Planning

7.3 Criteria for the hydrogen network expansion proposal

This chapter explains the seven criteria for hydrogen developed for the modelling year 2037. These criteria were applied to each network expansion measure. The results can be found in Appendix 3.

H_2(1): Core network measures resulting from the modelling in all three scenarios for the year 2037 have been included in the network expansion proposal. The commissioning dates for individual measures can be adjusted. Further details can be found in Appendix 3.

H_2(2): Core network measures resulting from the modelling in at least one of the three scenarios for 2037 have been included in the network expansion proposal. The dimensions and commissioning date of individual measures are adjusted to reflect current market developments. In subsequent network development plans, specific market requirements are used to determine when and in what dimensions the respective measure is needed.

H_2(3): Core network measures that are not required in any of the three scenarios for 2037 have not been included in the network expansion proposal.

H_2(4): Additional measures (new construction or conversion) beyond the core network resulting from the modelling in all three scenarios for 2037 have been included in the network expansion proposal.

H_2(5): Additional measures (new construction or conversion) beyond the core network that are not included in the modelling results for 2037 in all three scenarios have generally not been included in the network expansion proposal. The need for these projects will be reviewed in subsequent network development plans. Any exceptions are described in criterion H_2(6).

H_2(6): Conversion measures beyond the core network that are not required in all three scenarios for 2037 but can be converted in all three scenarios in 2037 without requiring natural gas-reinforcing measures have been included in the network expansion proposal due to their convertibility to hydrogen.

H_2(7): New construction measures that go beyond the scope planned for 2037 as part of the network expansion proposal and will be required in 2045 have not been included in the network expansion proposal.

7.4 Hydrogen network expansion proposal and adjustments to core network measures

As part of the review of the approved core network pursuant to Section 28q(8) EnWG and the possibility of extending the timeframe of core network measures pursuant to Section 28q(8) sentence 6 EnWG until the end of 2037, adjustments were made to core network measures for the network expansion proposal. In Section 7 of the approval of the Scenario Framework 2025, the BNetzA granted hydrogen core network operators a certain degree of flexibility in making adjustments to approved core network measures. Section II.B.9 of the approval of the Scenario Framework 2025 provides examples of rules for possible adjustments.

The reasons for making adjustments to network expansion measures are manifold and cannot always be attributed to a single cause. They result primarily from:

(1) Adjustments to commissioning dates based on modelling results

(2) Adjustments based on recent developments in the market ramp-up

(3) Adjustments in the course of implementing core network measures, e.g. changes to route planning; better coordination of the construction work for various measures

(4) Adjustments to commissioning dates in accordance with the availability of adjacent transport pipelines

(5) Obstacles to measure implementation, e.g. market situation, cost increases, bottlenecks at service providers and more difficult requirements from the German Sector Regulation (SektVO) for the procurement of materials and services

(6) Delays in the approval process, e.g. expected acceleration in obtaining building permits by the planning approval authority did not occur; expected Hydrogen Acceleration Act (WassBG) did not materialise

(7) Later conversion of measures due to natural gas-reinforcing measures (costly and time-consuming measures in methane to ensure security of supply)

The implementation of the core network with all associated measures by 31 December 2037 remains realistically possible, regardless of the adjusted commissioning dates. There is also sufficient lead time for the realisation of all core network measures that do not yet have a project sponsor. In addition, where deemed necessary by the hydrogen transmission system operators, work on the initial project steps has already begun.

The expansion measures newly identified to supplement the core network will also selectively complement and strengthen the future German hydrogen network. For the sake of clarity, it should be noted that the new expansion measures are not part of the core network under Section 28q of the Energy Industry Act (EnWG) and are therefore not subject to the financing conditions of the amortisation account under Sections 28r and 28s EnWG. For these new measures in the hydrogen network expansion proposal, the hydrogen transmission system operators will therefore not designate any project sponsor for the time being. The need for these projects will be reviewed again in the upcoming network development plans, taking market developments into account. The implementation of new projects will require binding regional requirements to be defined. This binding nature can be achieved, for example, through the definition of implementation roadmaps.

The hydrogen network expansion proposal is presented in Table 43: and Figure 50 and takes account of the above criteria. The relevant hydrogen projects are set out in Annex 9.

Table 43: Hydrogen network expansion proposal

Results of hydrogen network expansion proposal*	
Technical parameters	
Compressor capacity [MW]	255
Pipelines [km]	7,040
- of which pipelines to be repurposed [km]	3,658
- of which newly built pipelines [km]	3,196
- of which newly built pipelines (offshore) [km]	186
- For information: Czech-German Hydrogen Interconnector (CGHI)** [km]	168
Total investment [billion euros]	**20.3**
Compressor stations	2.0
Pipelines (including costs for M&R stations)	18.3
- of which pipelines to be repurposed	2.5
- of which newly built pipelines	14.0
- of which newly built pipelines (offshore)	1.9

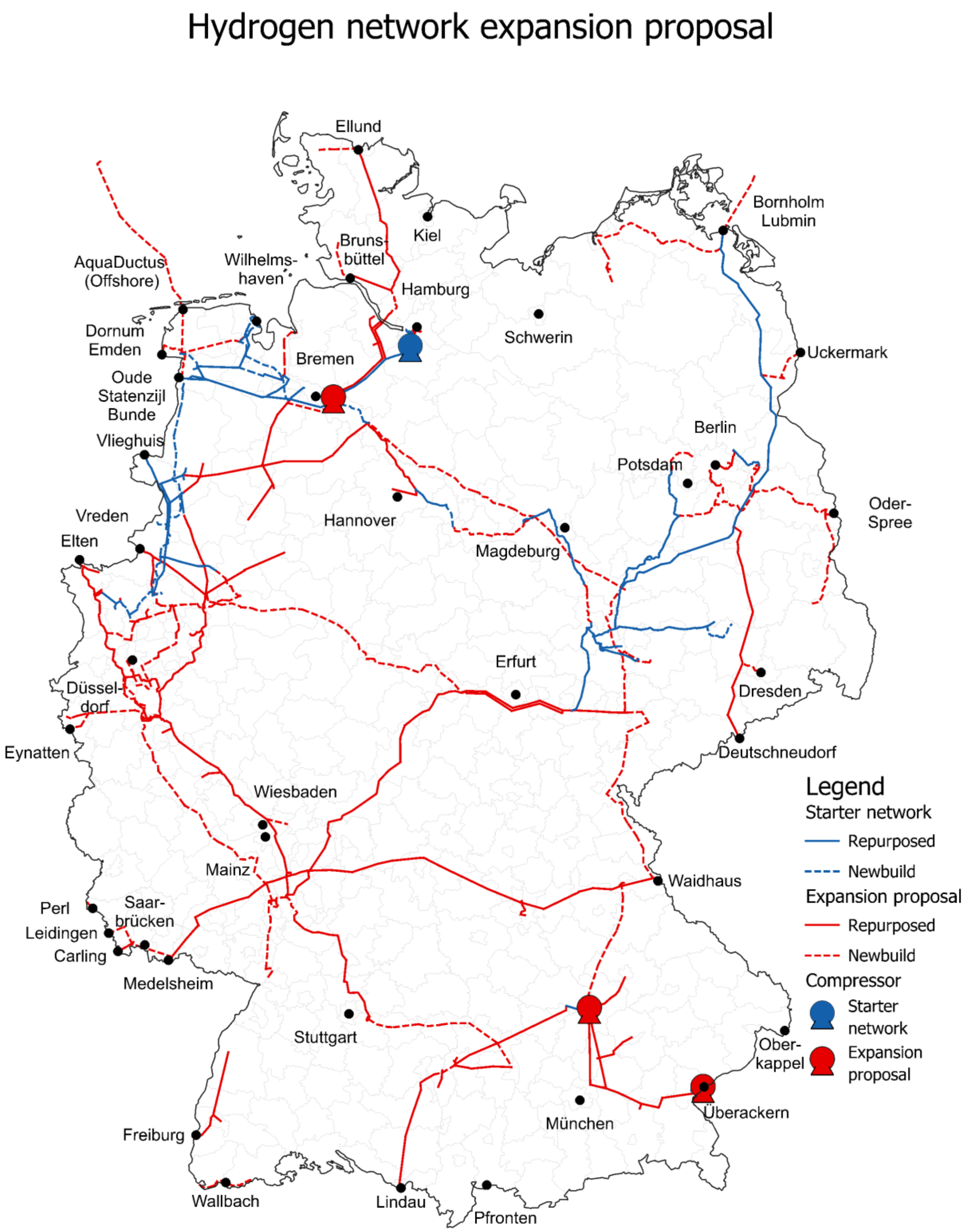
* rounded figures

** CGHI was taken into account in the modelling but is not part of the German hydrogen network.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

The network expansion proposal for hydrogen covers a pipeline length of around 7,040 km with an investment volume of around €20.3 billion. Adding the hydrogen starter network measures with a pipeline length of 2,201 km (investment volume around €4.0 billion) gives a total hydrogen infrastructure length of 9,241 km (investment volume around €24.4 billion).

Figure 50: Hydrogen network expansion proposal



Source: Coordination Office for Gas and Hydrogen Network Development Planning

The hydrogen transmission system operators have published a detailed hydrogen action map for the proposed hydrogen network expansion (see Appendix 4).

7.5 Further aspects of individual network expansion measures

MEGAL section from Gernsheim to Rothenstadt

Contrary to the assumption that all pipelines earmarked for the core network can be made available for hydrogen by the end of 2032, the MEGAL pipeline section from Gernsheim to Rothenstadt (H2-084-01, H2-085-01) will still be needed for methane transportation in 2030 due to the emerging slight decline in methane demand and additional demand from power plants. Removing it by 2032 would entail significant natural gas-reinforcing measures. The hydrogen calculations for 2037 in scenarios 1, 2 and 3 have shown that the demand for hydrogen transportation capacity only requires the MEGAL pipeline section between Gernsheim and Rothenstadt to be switched from methane to hydrogen in scenarios 1 and 2. Commissioning of this project will therefore be postponed from 12/2032, as confirmed in the core network approval, to 12/2034. The Gas and Hydrogen Network Development Plan 2027 will review the possible convertibility in 12/2034. As the natural gas-reinforcing measures planned at the Rimpar compressor station (1048-01), the Rothenstadt compressor station (1049-01) and the MEGAL Loop Rimpar-Hüttendorf (1047-01) are also not needed in scenarios 1 and 2, they are removed from the Gas and Hydrogen Network Development Plan 2025.

Network concept for Neuss and Düsseldorf

The new construction projects in the Düsseldorf area (Nievenheim-Neuss pipeline; Neuss-Neuss Hafen pipeline) are part of a regional development concept based on specific customer requirements. Customers have already entered into contractual obligations with Thyssengas H2, and the project is currently in the feasibility study phase. Since the customer requirements were not included in in scenario 3, the newbuild pipelines in the concept did not fully meet criterion 4 for hydrogen (see Appendix 3). The conversion pipelines also included in the concept meet criterion 6 for hydrogen and are therefore part of the network expansion proposal. The hydrogen transmission system operators consider this to be a special case due to the high level of concretisation and need-based requirements from customers and are therefore proposing the project as part of the network expansion proposal. The commissioning date has been set for 12/2036 in accordance with the underlying system for new projects in this network development plan. Regardless of these circumstances, the hydrogen transmission system operators involved (OGE/Thyssengas H2) are endeavouring to meet customer requests for earlier project delivery.

Adjustment of hydrogen infrastructure planning in northwest Germany

The core network measure KLN029-01 Wilhelmshaven-Wardenburg (NDP ID H2-1029-01) was adjusted due to changed input parameters and subsequently as a result of modelling. These changes were necessary following the relocation of the offshore pipeline connection and the removal of the KLN024-01 Barßel-Wardenburg and KLN031-01 Barßel-Emsbüren measures from the core network approval. The core network measure KLN029-01 now plays a more prominent role in the distribution and transmission of hydrogen from western to eastern Germany. For this reason, the endpoint of the pipeline will now be further east in Ganderkesee instead of in Wardenburg. Consequently, the KLN025-01 Wardenburg-Ganderkesee is no longer needed and has therefore not been included in the expansion proposal, which improves the cost efficiency of the core network. The new starting and end points of the pipeline are supported by the findings of initial route studies.

The amended route for the KLN029-01 Wilhelmshaven-Wardenburg pipeline and the postponement of the commissioning date have an impact on the original core network measure KLN019-01 Rastede-Wiefelstede (NDP-ID H2-1019-01). The KLN019-01 Rastede-Wiefelstede pipeline would no longer be available for transport without some changes to its technical parameters, so the length of the KLN019-01 pipeline has been extended by approximately 10 km. This has shifted the endpoint of the pipeline, which has now been renamed the Rastede-Westerstede pipeline.

Reinstatement of the Ellund-Niebüll core network pipeline (KLN022-01)

As part of the hydrogen modelling for the three scenarios in 2037, the draft Gas and Hydrogen Network Development Plan 2025 concluded that the Ellund-Niebüll core network pipeline (KLN022-01) was not technically required in terms of network-supporting in the target year 2037 under any of the scenarios considered. Consequently, the measure was not initially included in the hydrogen network expansion proposed in the draft Gas and Hydrogen Network Development Plan 2025. However, further analysis for the target year 2045 in the revised draft of the Gas and Hydrogen Network Development Plan 2025 has shown that the initially omitted pipeline fulfills a relevant network-supporting function in scenario 2 (2045).

During the consultation process, many stakeholders called for the measure to be included in the network expansion proposal. Particular reference was made to the dynamic project development since the 2024 market consultation, which has since become significantly more concrete.

The hydrogen transmission system operators therefore propose reinstating the core network measure Ellund-Niebüll (KLN022-01), which was omitted from the draft, in the revised draft of the Gas and Hydrogen Network Development Plan 2025 (NDP-ID H2-1022-01).

To appropriately reflect the still uncertain project environment and continuing market uncertainties, the hydrogen transmission system operators further propose extending the planning and implementation timeframe for the core network measure and, for the time being, postponing its commissioning date from December 2031 to December 2033, with the option of reassessing the need for its implementation in the forthcoming 2027 Network Development Plan.

Concluding Remarks and Outlook 8

8 Concluding Remarks and Outlook

The gas TSOs and hydrogen transmission system operators have submitted the consulted and revised draft to the regulatory authority for approval. The BNetzA will review this revised draft to ensure compliance with applicable statutory requirements. As part of this process, the regulatory authority may require the gas TSOs and hydrogen transmission system operators to amend the Network Development Plan by issuing a formal request for amendments. The regulatory authority will subsequently consult on the revised draft and, taking into account the outcome of the public consultation, approve the Gas and Hydrogen Network Development Plan submitted by the gas TSOs and regulated hydrogen transmission system operators.

Annexes and Appendices

Annexes

Appendices

Glossary

Glossary

Transmission system operators

Aqua Ductus Pipeline	Aqua Ductus Pipeline GmbH
bayernets	bayernets GmbH
Ferngas	Ferngas Netzgesellschaft mbH
Fluxys	Fluxys TENP GmbH
Fluxys D	Fluxys Deutschland GmbH
GASCADE	GASCADE Gastransport GmbH
GTG Nord	Gastransport Nord GmbH
GUD	Gasunie Deutschland Transport Services GmbH
LBTG	Lubmin-Brandov Gastransport GmbH
NaTran_D	NaTran Deutschland GmbH
NGT	NEL Gastransport GmbH
Nowega	Nowega GmbH
OGE	Open Grid Europe GmbH
ONTRAS	ONTRAS Gastransport GmbH
terranets	terranets bw GmbH
Thyssengas	Thyssengas GmbH
Thyssengas H2	Thyssengas H2 GmbH

DSOs/Hydrogen core network operators

badenova	badenovaNETZE
Creos	Creos Deutschland GmbH/Creos Deutschland Wasserstoff GmbH
Hamburger Energienetze	Hamburger Energienetze GmbH
NBB	NBB Netzgesellschaft Berlin-Brandenburg mbH & Co. KG
N-ERGIE Netz	N-ERGIE Netz GmbH
Netze BW	Netze BW GmbH
RheinEnergie	RheinEnergie AG/Rheinische Netzgesellschaft mbH
SachsenNetze	SachsenNetze GmbH
Schleswig-Holstein Netz	Schleswig-Holstein Netz AG

Other acronyms and abbreviations

ACER	Agency for the Cooperation of Energy Regulators

ANIKA	BNetzA ruling on the "Recognition of instruments for increasing capacity"
bar	Pressure relative to sea level
BKartA	Federal Cartel Office
BNetzA	Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railways
BVEG	Federal Association of Natural Gas, Oil and Geoenergy
CCGT	Combined-cycle gas turbine
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
cFAC (temp)	Conditionally firm, freely allocable capacity (temperature-dependent)
CGHI	Czech-German Hydrogen Interconnector
CGT	Power plant
CH_4	Methane
CHP	Combined heat and power plant
Cross-border IP	Cross-border interconnection point
CS	Compressor station
CTS	Trade/commerce/services
DAC	Dynamically allocable capacity
dena	German Energy Agency
DN	Nominal diameter
DP	Design pressure
DSO	Distribution system operator
DSO-HCNO	Distribution system operator/hydrogen core network operator
DVGW	German Technical and Scientific Association for Gas and Water
ENTSO-G	European Network of Transmission System Operators for Gas
EnWG	German Energy Industry Act
eTSO	Electricity transmission system operator
EU	European Union
EUGAL	European Gas Interconnector
FAC	Freely allocable capacity
fDAC	Firm, dynamically allocable capacity
FID	Final Investment Decision
FSRU	Floating storage and regasification units
Gas TSO	(Gas) gas transmission system operators
GasNZV	Regulation on access to gas supply networks/Gas Network Access Regulation

Green gases	Hydrogen and synthetic methane
GTP	Gas network area transformation plan
GTS	Gasunie Transport Services B.V.
GW_e	Electrical (connection) rating in gigawatts
GWh	Gigawatt hour
GWh/h	Gigawatt hours per hour
GW_{th}	Thermal (connection) capacity in gigawatts
GY	Gas year
H_2	Hydrogen
HCNO	Hydrogen core network operator
H-gas	Methane with a high calorific value
HTNO	Hydrogen transmission network operator
ID	Identification number
INES	Initiative Energien Speichern e.V.
Inlet compressor	Compressor unit used at cross-border IPs to increase the inlet pressure into the gas pipeline system and to ensure gas transportation
JAGAL	Jamal-Gas-Anbindungs-Leitung (Jamal Gas Connection Pipeline)
KARLA Gas 2.0	BNetzA ruling on capacity regulations and network access in the gas sector
KASPAR	BNetzA ruling on standardisation of capacity products in the gas sector (capacity product standardisation)
KO.NEP	Coordination Office for Gas and Hydrogen Network Development Planning
KSG	Federal Climate Protection Act
KW	Power plant
LFC	Load flow commitment
L-gas	Methane with a low calorific value
LH_2	Liquid hydrogen
LNG	Liquefied natural gas
Loop line	Pipeline laid parallel to an existing pipeline
LTF	Long-term forecast by distribution system operators
M&R station	Gas metering and pressure regulation station
Main line compressor	Compressor unit used in a transmission pipeline to compensate for pressure losses and ensure the transportation of gases
MBI	Market-based instrument
MEGAL	Mittel-Europäische Gasleitung(sgesellschaft)
MWh	Megawatt hour

NC CAM	Network Codes Capacity Allocation Mechanisms
NDP	Network Development Plan
NEL	Nordeuropäische Erdgasleitung (North European Gas Pipeline)
NIP	Network interconnection point
NRL	Nordsee-Ruhr-Link (North Sea-Ruhr Link)
OPAL	Ostsee-Anbindungsleitung (Baltic Sea Connection Pipeline)
PCI	Project of Common Interest
PGU	Power generating unit
PHH	Private households
PMI	Projects of Mutual Interest
PtG	Power-to-gas
RLM	Registered demand measurement
SektVO	Sector Regulation – Regulation on the award of public transport, drinking water supply and energy supply contracts
SEL	Süddeutsche Erdgasleitung (Southern German Natural Gas Pipeline)
SF	Scenario Framework
STEGAL	Sachsen-Thüringen-Erdgas-Leitung (Saxony-Thuringia-Natural Gas Pipeline)
TENP	Trans-Europa-Naturgas-Leitung (Trans-European Natural Gas Pipeline)
THE	Trading Hub Europe
TWh	terawatt hour
TYNDP	Ten-Year Network Development Plan (by ENTSOG)
UGS	Underground storage facility
VIP	Virtual Interconnection Point
VKU	Association of Municipal Companies
VTP	Virtual trading point
WassBG	Hydrogen Acceleration Act
WEB	Hydrogen production and demand survey
WKL	Wilhelmshaven-Küsten-Leitung (Wilhelmshaven Coastal Pipeline)

Literature

Literature

[BNetzA 2024] Monitoring Report 2024, download at (downloaded on 12 February 2026): https://data.bundesnetzagentur.de/Federal Network Agency/SharedDocs/Mediathek/Monitoringberichte/MonitoringberichtEnergie2024.pdf

[BNetzA 2025] Approval of the Scenario Framework for the Gas and Hydrogen Network Development Plan 2025–2037/2045, download at (downloaded on 16 February 2026): https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/NDP/DL_Scenario Framework/Genehm_SR_2025Gas.pdf?__blob=publicationFile&v=2

[BVEG/DVGW/INES 2022] " Wasserstoff speichern – soviel ist sicher. Transformationspfade für Gasspeicher" *("Storing hydrogen – this much is certain, transformation paths for gas storage")*, download at (downloaded on 10 February 2026): https://www.bveg.de/wp–content/uploads/2022/06/20220610_DBI–Studie_Wasserstoff–speichern–soviel–ist–sicher_Transformationspfade–fuer–Gasspeicher.pdf

[dena 2025] Biomethane feed-in atlas, download at (downloaded on 10 February 2026): https://www.dena.de/biogaspartner/biomethan/einspeiseatlas/

[EU 2024] Regulation (EU) 2024/1789 of the European Parliament and of the Council, download at (downloaded on 10 February 2026): https://eur–lex.europa.eu/legal–content/EN/TXT/PDF/?uri=OJ:L_202401789

[EC 2025] Union list of projects of common interest and projects of mutual interest, download at (downloaded on 10 February 2026): https://ec.europa.eu/info/law/better–regulation/have–your–say/initiatives/14607–2nd–PCI–PMI–list–under–the–TEN–E–Regulation_en

[TSO Gas 2024] Interim report on L-to-H-gas conversion 2024, download at (downloaded on 10 February 2026): https://fnb–gas.de/wp–content/uploads/2024/04/2024_04_23_Veroeffentlichung–L–H–Gas–conversion.pdf

[KO.NEP 2024] Draft Scenario Framework for the Gas and Hydrogen Network Development Plan 2025, download at (downloaded on 1 February 2026): https://ko-nep.de/wp-content/uploads/2024/03/Scenario Framework_2025_final.pdf

[MCPGG 2024] Ministry of Climate Policy and Green Growth, L-Gas Market Conversion Review – Summer Briefing 2024, download at (downloaded on 17 February 2026): https://www.tweedekamer.nl/kamerstukken/detail?id=2024D43140&did=2024D43140

[MEK 2023] Ministerie van Economische Zaken en Klimaat, "Gaswinning Groningen stopt definitief", download at (downloaded on 17 February 2026): https://www.rijksoverheid.nl/actueel/nieuws/2023/09/22/gaswinning–groningen–stopt–definitief