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Draft Gas and Hydrogen Network Development Plan 2025

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Legal notice

Draft Gas and Hydrogen Network Development Plan 2025

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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 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 network 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 operators of hydrogen transmission networks 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 initial network measures.

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 operators of hydrogen transmission networks to meet energy and climate policy objectives.

Table 1: Network expansion proposal for methane and hydrogen

Results of the methane network expansion proposal	
Technical parameters	
Pipelines [km]	364
Compressor capacity [MW]	0
Total investment [billion euros]	**2.9**
- of which network expansion measures from NDP 2022	1
- 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

Results of hydrogen network expansion proposal*	
Technical parameters	
Compressor capacity [MW]	255
Pipelines [km]	7,007
- of which pipelines to be repurposed [km]	3,658
- of which newly built pipelines [km]	3,163
- of which newly built pipelines (offshore) [km]	186
- For information: Czech-German Hydrogen Interconnector (CGHI)** [km]	168
Total investment [billion euros]	**20.1**
Compressor stations	1.9
Pipelines (incl. M&R station costs)	18.2
- of which pipelines to be repurposed	2.5
- of which newly built pipelines	13.9
- of which newly built pipelines (offshore)	1.9

* rounded values

** 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 364 km and total investments of €2.9 billion for methane and 7,007 km and around €20,1 billion for hydrogen by 2037 (plus 2,154 km and €4.1 billion of the originally approved hydrogen core network, which has already been delivered as the initial 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 operators of hydrogen transmission networks will also populate 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.

Two-stage approach: Outlook for the revised draft of the Gas and Hydrogen Network Development Plan 2025

The integrated review of methane and hydrogen network planning, as well as the inclusion of three scenarios to be modelled for the years 2037 and 2045 and the methane scenario for 2030, called for new methodological approaches and thus led to a greater need for analysis than before. To allow proper and thorough processing, the gas TSOs and operators of hydrogen transmission networks are publishing the Gas and Hydrogen Network Development Plan 2025 in two stages. The modelling results for hydrogen in the reference year 2045 will be included in the revised draft of the Gas and Hydrogen Network Development Plan 2025, as will the modelling of market-based instruments.

Foreword

Foreword

Dear reader,

With this document, the Coordination Office for Gas and Hydrogen Network Development Planning is submitting the draft Gas and Hydrogen Network Development Plan 2025 prepared by the gas TSOs and operators of hydrogen transmission for consultation.

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 operators of hydrogen transmission networks 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 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.

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 operators of hydrogen transmission networks therefore have an equal obligation and responsibility to develop these plans. The 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 took into account the challenges of achieving 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 of the German Energy Industry Act 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) within the specified time frame.

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 operators of hydrogen transmission networks 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 then examines the draft or, if a change request was issued, the revised draft, and then approves the draft Gas and Hydrogen Network Development Plan submitted by the gas TSOs and operators of hydrogen transmission networks or, if a change request was issued, the revised draft, 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].

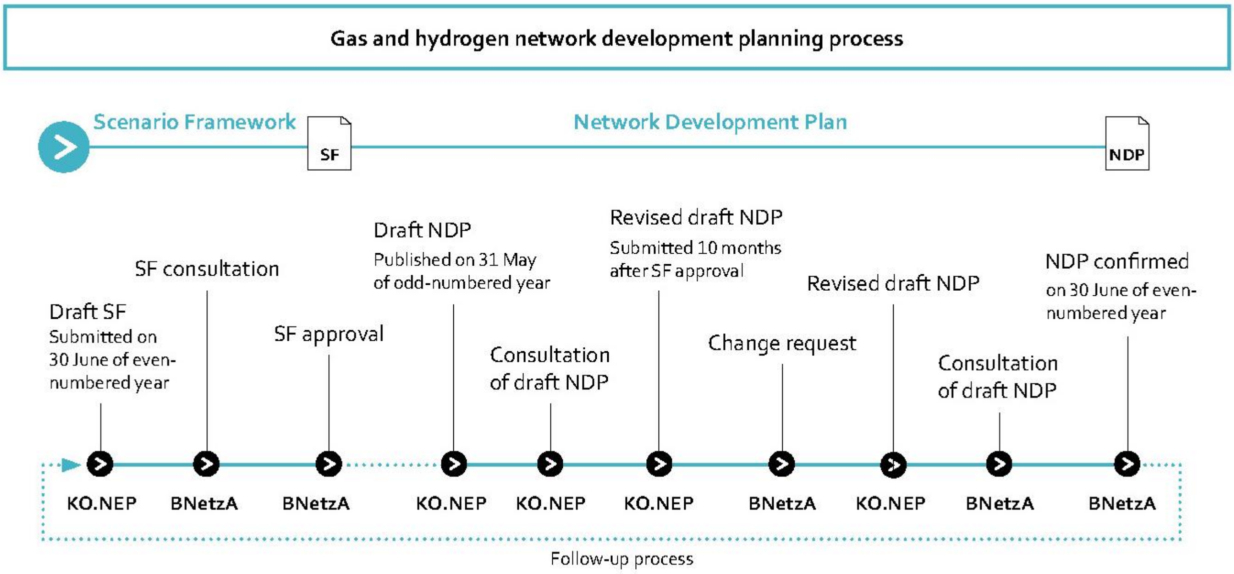
1.2 Timeline and structure of the Gas and Hydrogen Network Development Plan 2025

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

Based on the Scenario Framework (ref. 4.13.01/11#1) approved by the BNetzA on 30 April 2025, the transmission system operators have drawn up this draft Gas and Hydrogen Network Development Plan 2025.

The draft of the Gas and Hydrogen Network Development Plan 2025 is published in two stages, as provided for in Sections 15c and 15d of the EnWG. The draft Gas and Hydrogen Network Development Plan 2025 is published and made available for consultation by KO.NEP. The public, including existing or potential network users and affected network operators, then have the opportunity until 27 March 2026 to submit any comments to KO.NEP. The gas TSOs and operators of hydrogen transmission networks will subsequently revise the draft Gas and Hydrogen Network Development Plan 2025 and make the revised document available to the BNetzA for consultation.

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 operators of hydrogen transmission networks. 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 connections between methane and hydrogen, the draft Gas and Hydrogen Network Development Plan 2025 contains the modelling results for methane for the years 2030, 2037 and 2045, as well as the results for hydrogen in 2037. It also provides an outlook on the hydrogen infrastructure in 2045, which, based on the modelling results for hydrogen in 2037, also shows pipelines that could be repurposed. This interconnected infrastructure then serves as the basis for hydrogen modelling for 2045. The results of this modelling process and a more detailed analysis of capacities at cross-border interconnection points (cross-border IPs) for 2037 that do not require expansion are presented in the revised draft of the Gas and Hydrogen Network Development Plan 2025.

The revised draft also shows the results of the modelling of market-based instruments (MBIs) for methane, on which all modelling is based.

The network expansion proposal based on the modelling results up to 2037 is part of this draft Gas and Hydrogen Network Development Plan 2025.

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.

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 1st draft" available in the Gas NDP database. All available data can be downloaded.

With the revised draft of the Gas and Hydrogen Network Development Plan 2025, the gas TSOs and operators of hydrogen transmission networks will also populate 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.

Approved Scenario Framework

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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 more 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

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

* 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

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	**	**	**	**	**	**

* Capacities 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 to be able 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.

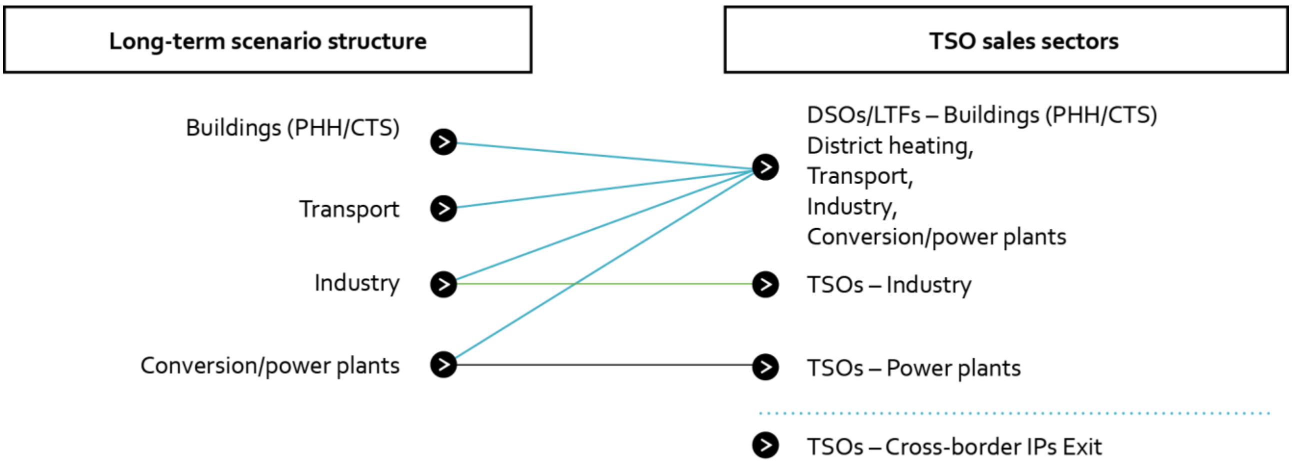
3.1.1 Demand-based approach

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 Gas Network Access Ordinance (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 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 chapter 3.3 entitled 'Input variables for methane' and chapter 3.4 entitled 'Input variables for hydrogen'.

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 Gas Network Access Ordinance (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 outputs (GWe) 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 outputs 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 outputs and the scenario's target values is to be filled with the addition of further hydrogen capacities at network-friendly 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 outputs specified 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 output of these power plants is then proportionally reduced until the overall figure of 17 GWe is reached (TSO power plants 10 GWe, DSO power plants 7 GWe).

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

Scenario 3 (2037): Scenario 3 depicts a delayed transformation from methane to hydrogen in the power plant sector, among others. An electrical output of 58 GWe 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 GWe, DSO power plants 16 GWe).

Regionalisation scenarios 1–3 (2045)

Scenario 3 (2045): This scenario is based on an electrical output of 22 GWe 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 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 output 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 output 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 – NEP 1. Entwurf" cycle in the "Capacities" tile. For the modelling year 2045, the gas connection ratings are shown in Table 30.

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 output 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		
	GWe		GWe	GWth
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 to 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 outputs 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 output 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 output 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 Czechia, 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 1st 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 output of 22 GWe. 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 facility locations for methane and hydrogen into account twice, unless it is a newly built 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 network-friendly 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 operators of hydrogen transmission networks 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 levels 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) 2024/25 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 2024/25 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.

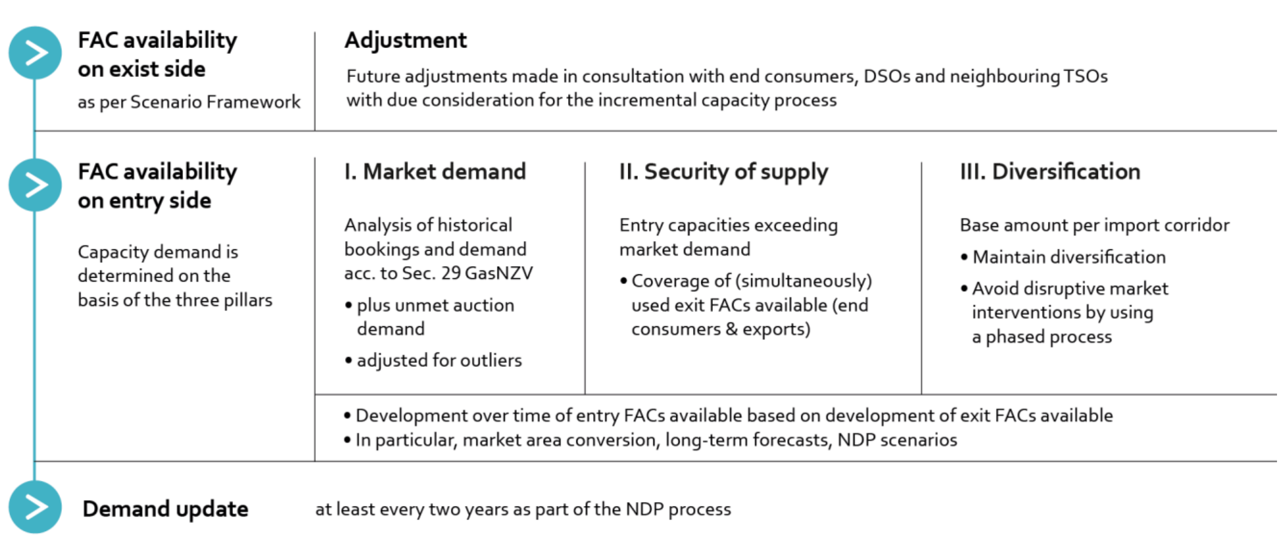
3.3.3.2 Methodology for determining the sufficient level

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 until 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

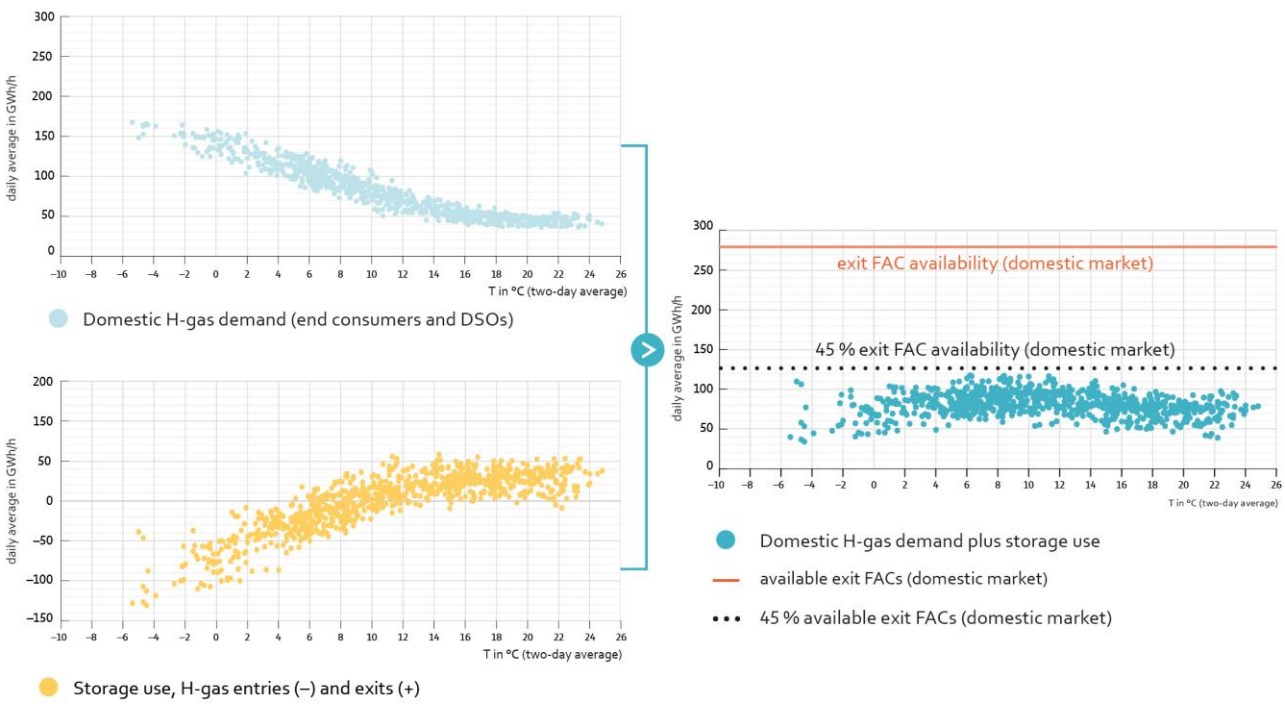
3.3.3.3 Sufficient level of exit FACs

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



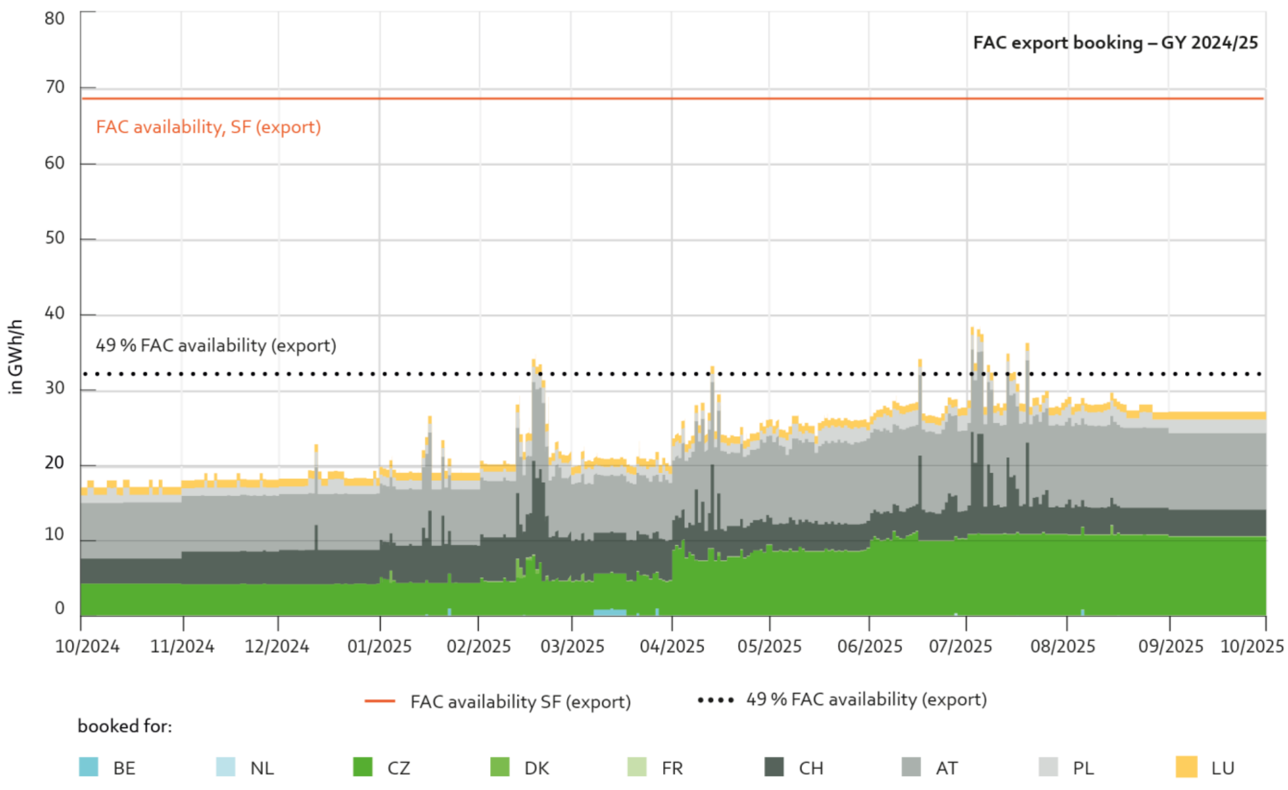
Source: Coordination Office for Gas and Hydrogen Network Development Planning

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 2024/25



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.

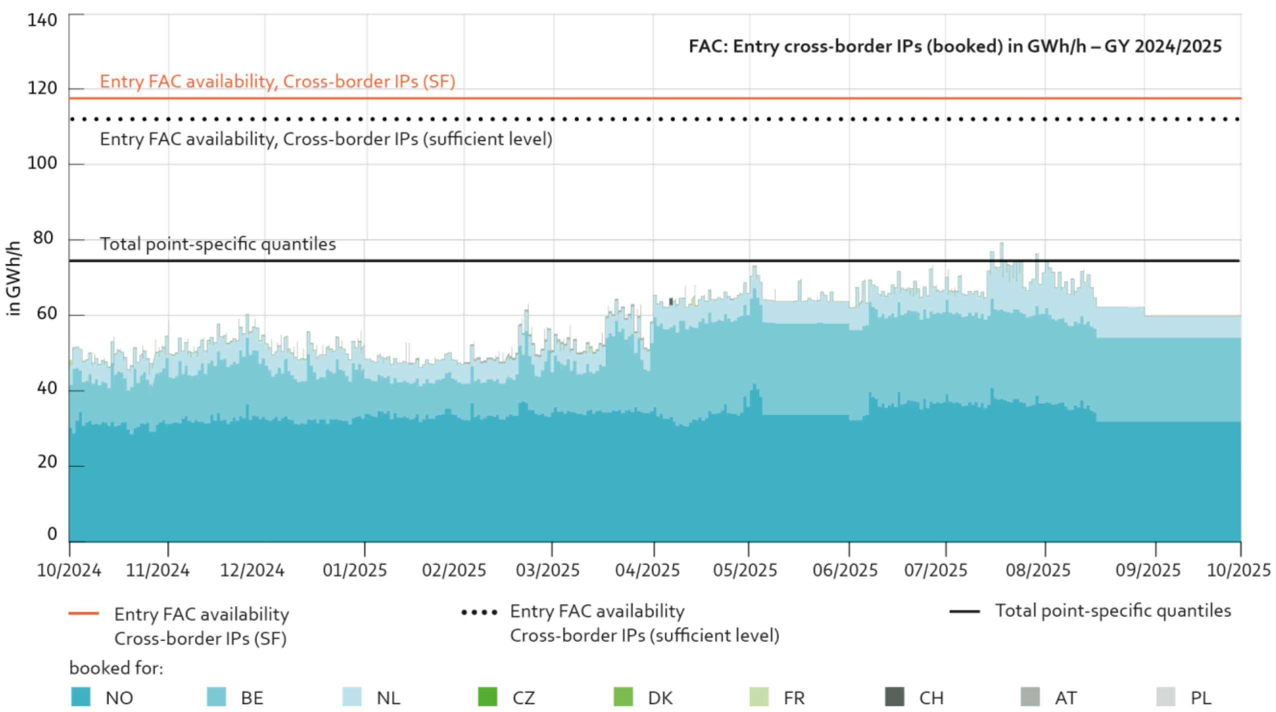
An analysis of historical data shows that the maximum simultaneous entry booking is significantly lower than what is on offer. From the gas transmission system operators' perspective, a reduction is therefore feasible without restricting market requirements and their flexibility, as both the amount of 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 2024/25 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 2024/25, 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.

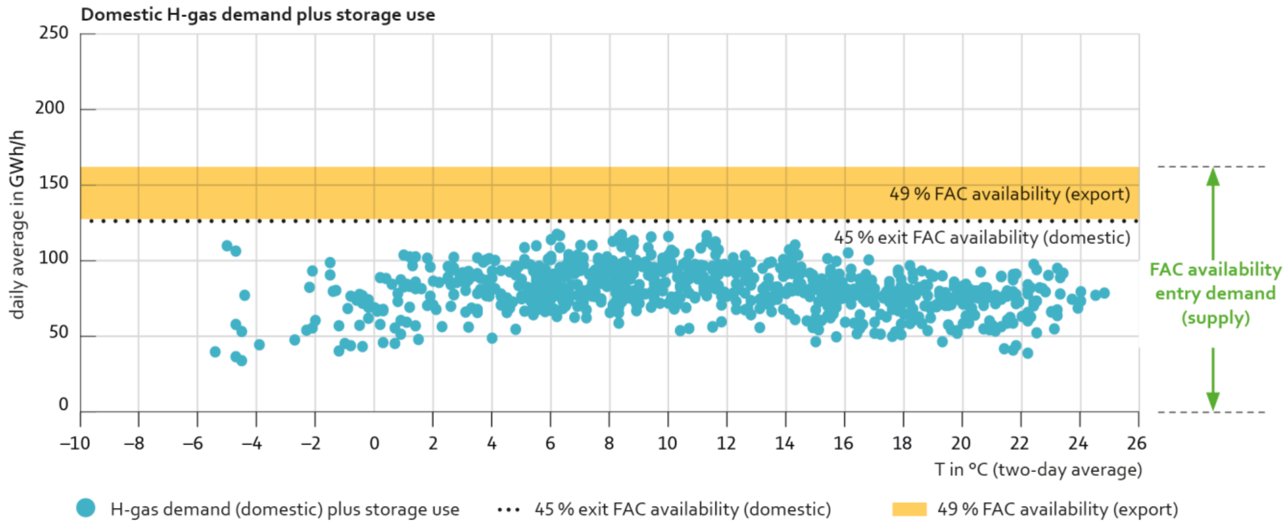
Consequently, the sufficient level of entry FACs for LNG will initially be determined on the basis of developments in the Scenario Framework. Adjustments to the Scenario Framework will only be made on the basis of changed assumptions regarding the commissioning of the onshore LNG terminals in the Wilhelmshaven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



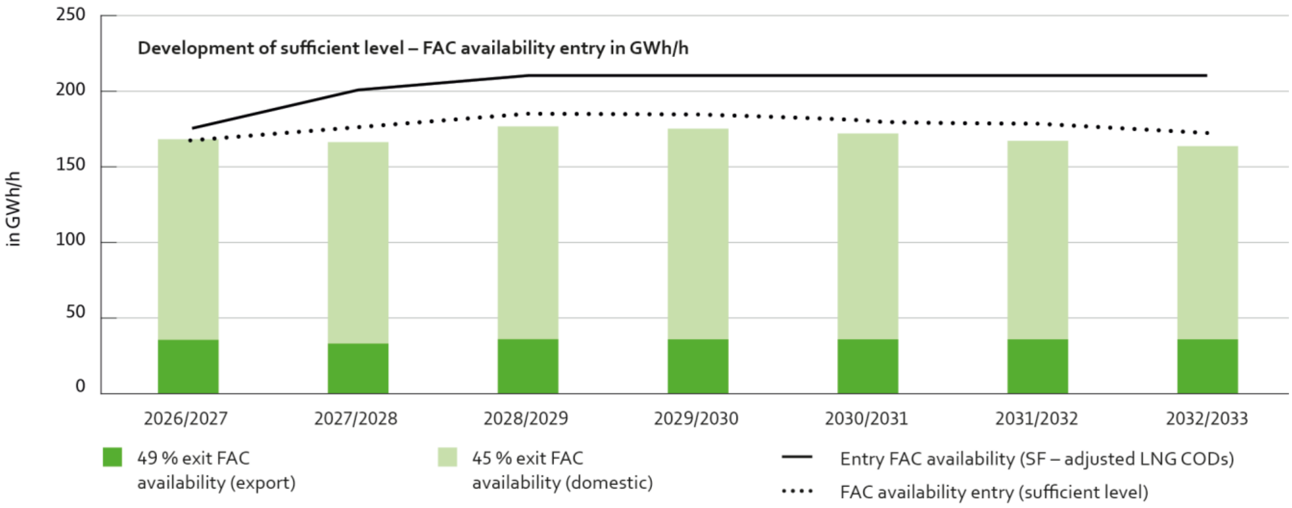
Source: Coordination Office for Gas and Hydrogen Network Development Planning

The sum of simultaneous demand for FAC exits for domestic consumption and export exceeds the market demand determined on the basis of GY 2024/25 (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.

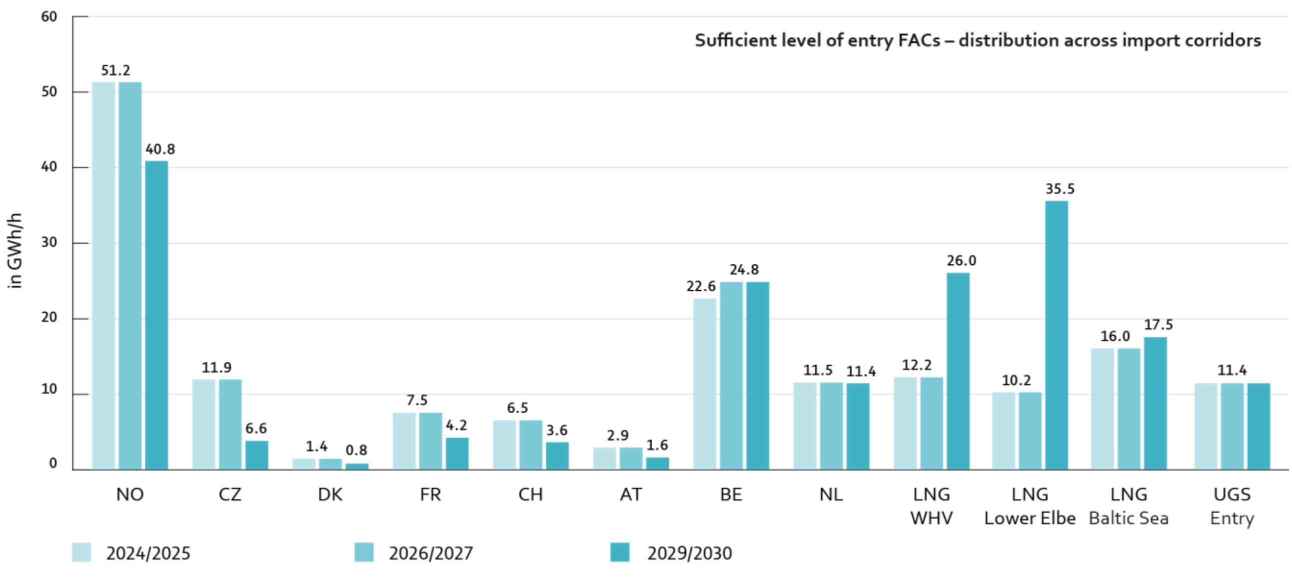
Figure 10: Sufficient level of entry FACs compared to the Scenario Framework – shares of cross-border IPs, LNG and underground storage facilities (UGS)



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 2024/25, 2026/27 and 2029/30. Import corridors with an entry capacity of less than 0.5 GWh/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 2024/25. Even under the new methodology, the allocation in GY 2026/27 is almost identical to the availability (supply) of entry FACs in GY 2024/25. 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 2024/25 can also be shown in GY 2029/30. For example, in the Norway import corridor, the supply in GY 2029/30 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 welcome 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 consultations 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 to 22 March 2024, the German electricity transmission system operators and operators of hydrogen transmission networks 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. The modelling approach used in the Gas and Hydrogen Network Development Plan 2025 required the market participants to clearly state the project capacity and the demand sector for each hydrogen project reported in the survey. 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 output 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 outputs 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 outputs of 29 GWe were specified. The required gas connection ratings for the individual locations were taken from the results of the market survey.

The ratio between electrical output and thermal output 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 output was adjusted. This procedure gave a thermal output of 61 GWth 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 outputs of 41 GWe were specified. The required gas connection ratings for the individual locations were taken from the results of the market survey.

The ratio between electrical output and thermal output 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 output was adjusted. This procedure gave a thermal output of 87 GWth 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 outputs of 5 GWe were specified. The required gas connection ratings for the individual locations were taken from the results of the market survey.

The ratio between electrical output and thermal output 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 output was adjusted. This procedure gave a thermal output of 11 GWth for these power plants.

Scenarios 1–3 (2045)

The electrical output specified by the BNetzA in scenario 1 for the year 2045 amounts to 60 GWe. In scenario 2, the output is 81 GWe. Scenario 3 also has an output of 81 GWe, which, in contrast to scenario 2, is composed of outputs 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 output of these power plants amounts to 22 GWe. Accordingly, the overall figures specified are an output of 22 GWe for methane and an output of 59 GWe 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 output of around 50 GWe were reported in the joint market survey for hydrogen, the BNetzA stipulates that the operators of hydrogen transmission networks 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 operators of hydrogen transmission networks 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 output and the lower electrical output 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 operators of hydrogen transmission networks 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 network-friendly 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 output, 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 output 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 output of the hydrogen projects of an additional project status exceeded the specified overall figure, the outputs 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 outputs 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 outputs 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 output (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 output 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 output 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 output 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 output 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 output 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 output 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 will be incorporated into the revised draft of the Gas and Hydrogen Network Development Plan 2025.

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 Czechia.

The operators of hydrogen transmission networks 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 operators of hydrogen transmission networks 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 operators of hydrogen transmission networks 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 for cross-border IPs contains 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.

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 operators of hydrogen transmission networks follow the stipulation in different ways according to the respective load case logic from chapter 3.4.5 .. This applies in particular to the *Cold dark doldrums* load case, 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 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 "basic evaluation/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 as for scenarios 1 and 2 (2037), but differs for the 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. Again, the procedure is basically the same as for scenarios 1 and 2 (2037), but differs for the different load cases.

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 operators of hydrogen transmission networks 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), but 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. Again, the procedure is basically the same as for scenarios 1 and 2 (2037), but differs for the different load cases.

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 gas 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 GWe, and projects with a total electrical output of 56 GWe 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 GWe to 40 GWe for 2035 and an entry capacity of 60 GWe to 80 GWe for 2045.

Scenario 1 (2037 and 2045)

For scenario 1, the BNetzA has specified an electrical output of 32 GWe 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 GWe for 2037 and 58 GWe for 2045.

The joint project base described above, with a total capacity of 32 GWe, forms the starting point in both years under consideration and must be taken into account in full. As in scenario 1, the operators of hydrogen transmission networks 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 operators of hydrogen transmission networks 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 "Basic evaluation/feasibility study" were included with adjusted output.

Scenario 3 (2037 and 2045)

For scenario 3, the BNetzA specifies a minimum value of 6 GWe for the year 2037. This value was determined by the BNetzA taking into account the specific conditions of scenario 3. In particular, it 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 GWe 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 CFD 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 operators of hydrogen transmission networks 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 network friendliness 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 preformed 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 – north-west, east and south – are tested here, resulting in three entry load cases.
- The *Cold dark doldrums* 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 methodological approach of the entry test is expanded to examine the *network friendliness of storage facilities*, i.e. the extent to which *storage facilities can support networks* when it comes to coping with high levels of renewable generation.

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

- *Entry test in the north-west*
- *Entry test in the east*
- *Entry test in the south*
- *Cold dark doldrums*
- *Network-friendly storage facilities*

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 (network-friendly 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). Based on the findings on modelling and determining the core network, three entry regions (north-west, 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 Figure 12.

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 *Cold dark doldrums* 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 network-friendly storage facility use 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 *("network friendliness")* were taken into account.

The *network-friendly 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 network-friendly 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 by the storage facility in the entry zone withdrawing 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 network-friendly 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 *Cold dark doldrums* 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* in particular proved to have a particularly adverse impact on the network. In order to ensure the efficiency of any network expansion, the above system of network-friendly storage use was applied to the *Entry test in the northwest* for all scenarios and years considered (*Network-friendly storage facilities* load case). The key element of this approach is the beneficial potential of flexible and network-friendly cavern storage capacities in the northwest entry zone, which are not available to the same extent in the other entry zones.

Status of network expansion measures

4

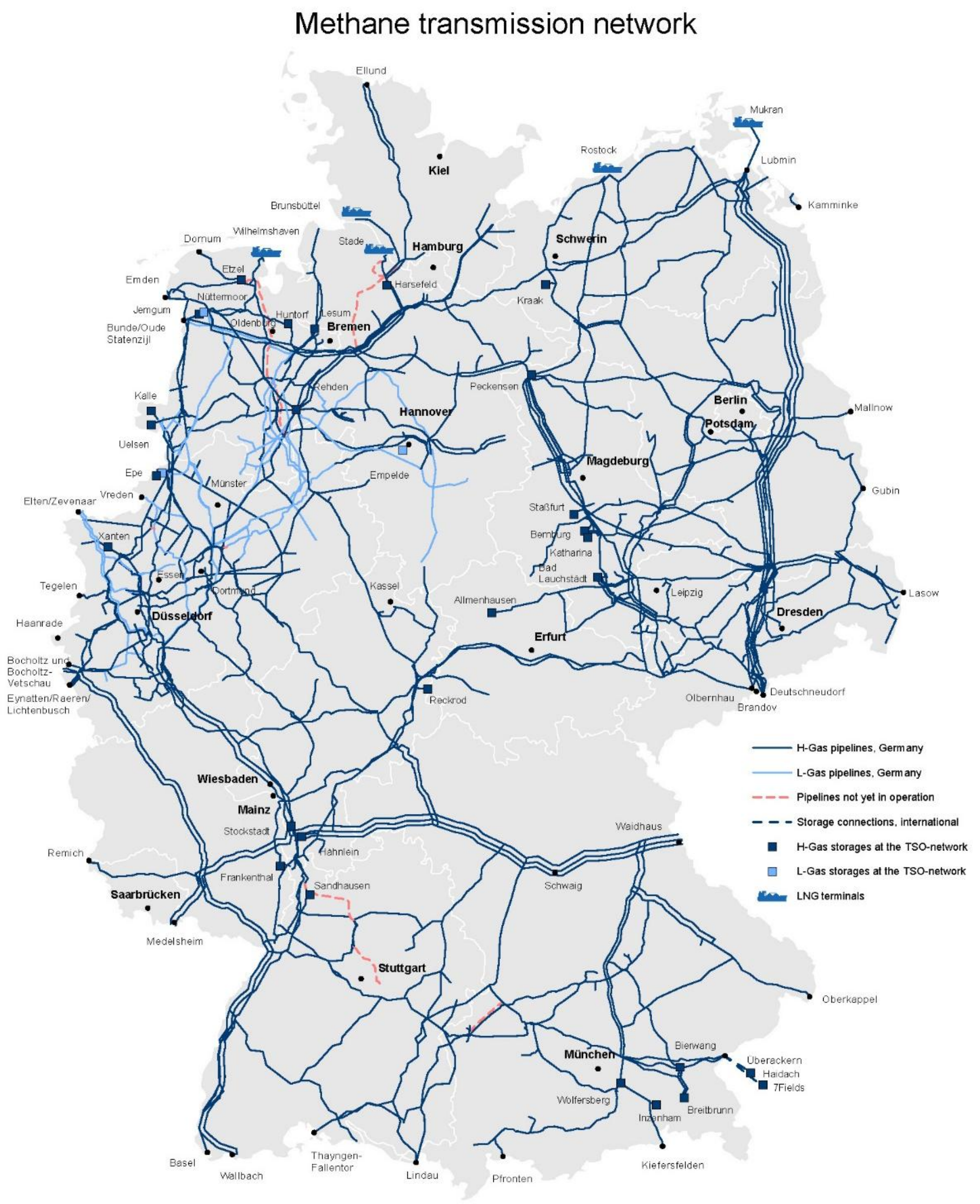
4 Status of network expansion measures

Chapter 4.1 provides an overview of the gas transmission network as on 1 September 2025, while chapter 4.2 describes the initial 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, thus fulfilling 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 networks are shown in Figure 13.

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 initial 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 initial 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 initial network for hydrogen network modelling. Similarly, the initial 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 7) or from the core network approval (Table 8), 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 7: Methane projects commissioned by 1 September 2025

No.	ID number	Network expansion measure	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	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 2M&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 North
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	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 North
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	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 North
82	863-01	Westerstede M&R station	GTG North
83	864-01	Sande M&R station	GTG North
84	865-01	Leer M&R station and connecting pipeline	GTG North
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 Gas transport/ ONTRAS

No.	ID number	Network expansion measure	TSO
89	883-01	Expansion of Radeland 2	Fluxys D/GASCADE/GUD/ONTRAS
90	901-01	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 gas transport/ONTRAS/OPAL gas transport
94	914-01	OPAL-STEGAL connection	GASCADE/Lubmin-Brandov gas transport/ OPAL gas transport
95	915-02	Connection pipeline to industrial port in Lubmin	Fluxys D/GUD/Lubmin-Brandov gas transport/ NEL gas transport/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 8: Hydrogen projects commissioned by 1 September 2025

No.	ID number	Network expansion measure	/HTNO
1	KLN033-01a	Hanekenfähr-Schepsdorf 1 incl. M&R stations	Nowega
2	KLN101-01	Leuna South-Leuna South 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 South 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 9: Methane projects under construction (as of 1 September 2025)

No	ID number	Network expansion measure	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	527-02	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 10: 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	H2-003-01	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	H2-013-01	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 North 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	KLU066-01	H2-066-01	GetH2 Emsbüren-Bad Bentheim pipeline incl. M&R stations	OGE
23	KLU087-01	H2-087-01	GetH2 Bad Bentheim-Ledgen pipeline incl. M&R stations	OGE/Nowega
24	KLU088-01	H2-088-01	GetH2 Legden-Dorsten pipeline incl. M&R stations	OGE/Nowega
25	KLU097-01b	H2-097-01	Plaußig-Lüptitz pipeline incl. M&R stations	ONTRAS
26	KLU101-01	H2-101-01	Wefensleben-Wedringen pipeline incl. M&R stations	ONTRAS
27	KLU103-01	H2-103-01	Wedringen 1-Glöthe pipeline incl. M&R stations	ONTRAS
28	KLU129-01	H2-129-01	GETH2 Vlieghuis-Kalle pipeline incl. M&R stations	Thyssengas H2
29	KLU130-01	H2-130-01	GETH2 Kalle-Ochtrup pipeline incl. M&R stations	Thyssengas H2
30	KLN016-01	H2-1016-01	Elsfleth-Ranzenbüttel pipeline incl. M&R stations	GTG North
31	KLN048-01	H2-1048-01	GetH2 Heek-Epe pipeline incl. M&R stations	OGE/Nowega
32	KLN050-01	H2-1050-01	GetH2 Dorsten-Hamborn pipeline incl. M&R stations	OGE/Thyssengas H2
33	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 fulfill the aforementioned criteria for further projects to be included in the initial network.

Table 11: Further methane initial network measures (as of 1 September 2025)

No.	ID number	Network expansion measure	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 South-Achim pipeline	GUD
6	802-01	Lauchhammer valve station	GASCADE/GUD/ONTRAS/Fluxys D
7	839-02	Sonsbeck M&R station	Thyssengas/OGE
8	880-02	Construction of Wittenburg compressor station	NEL gas transport/GUD/Fluxys D

No.	ID number	Network expansion measure	TSO
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 initial network measures.

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

No.	Core network ID	NDP ID	Network expansion measure	HTNO/HCNO
1	AND037–01	H2–3037–01	Leversen-Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
2	AND038–01	H2–3038–01	Leversen-Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
3	AND039–01	H2–3039–01	Hamburg Süd pipeline incl. M&R stations	Hamburger Energienetze GmbH
4	AND067–01	H2–3067–01	Mühlberg-Röderau pipeline incl. M&R stations	SachsenNetze HS.HD GmbH
5	AND114–01	H2–3114–01	Röderau-Gröditz pipeline incl. M&R stations	SachsenNetze HS.HD GmbH
6	AND115–01	H2–3115–01	Röderau-Riesa pipeline incl. M&R stations	SachsenNetze HS.HD GmbH
7	AND119–01	H2–3119–01	Moorburg compressor station	Hamburger Energienetze GmbH
8	KLN004–01	H2–1004–01	Forchheim-Irsching pipeline incl. M&R stations	bayernets/OGE
9	KLN015–01	H2–1015–01	Emden-Ost-Nüttermoor pipeline incl. M&R stations	GTG North
10	KLN019–01	H2–1019–01	Rastede-Westerstede pipeline incl. M&R stations	GTG North
11	KLN023–01	H2–1023–01	Peine-Hallendorf pipeline incl. M&R stations	GUD
12	KLN027–01	H2–1027–01	Achim-Luttum/Lehringen pipeline incl. M&R stations	GUD
13	KLN029–01	H2–1029–01	Dykhausen-Ganderkesee pipeline incl. M&R stations	GUD

No.	Core network ID	NDP ID	Network expansion measure	HTNO/HCNO
14	KLN033-01b	H2-1033-01b	Hanekenfähr-Schepsdorf 2 pipeline incl.2 M&R stations	Nowega
15	KLN034–01	H2–1034–01	Lingen-Lingen North pipeline incl. M&R stations	Nowega
16	KLN035–01	H2–1035–01	H2ercules Wilhelmshaven-Coastal Pipeline (WKL) incl. M&R stations	OGE/GASCADE
17	KLN036–01	H2–1036–01	H2ercules North Sea-Ruhr-Link (NRL I) pipeline incl. M&R stations	OGE/GASCADE
18	KLN037–01	H2–1037–01	H2ercules North Sea-Ruhr-Link (NRL III) pipeline incl. M&R stations	OGE
19	KLN049–01	H2–1049–01	GetH2 Dorsten-Marl pipeline incl. M&R stations	OGE/Nowega
20	KLN066–01	H2–1066–01	Milzau-Milzau 1 pipeline incl. M&R stations	ONTRAS
21	KLN067–01	H2–1067–01	Nempitz-Kulkwitz pipeline incl. M&R stations	ONTRAS
22	KLN085–01	H2–1085–01	Amelsbüren pipeline, northern canal crossing – Amelsbüren southern canal crossing, incl. M&R stations	Thyssengas H2
23	KLN087–01	H2–1087–01	Wallach-Hohfeld pipeline incl. M&R stations	Thyssengas H2
24	KLN088–01	H2–1088–01	Möllen-Averbruch pipeline incl. M&R stations	Thyssengas H2
25	KLN099–01	H2–1099–01	Emsbüren Dorsten pipeline incl. M&R stations	Thyssengas H2/OGE
26	KLU001–01	H2–001–01	Forchheim-Münchsmünster pipeline incl. M&R stations	bayernets
27	KLU002–01	H2–002–01	Münchsmünster-Neustadt a. d. Donau pipeline incl. M&R stations	bayernets
28	KLU009–01	H2–009–01	Irsching-Kösching pipeline incl. M&R stations	bayernets
29	KLU012–01	H2–012–01	Zöllnitz-Bad Lauchstädt pipeline incl. M&R stations	Long-distance gas
30	KLU025-01a	H2-025-01a	Ranzenbüttel-Sandkrug pipeline incl. M&R stations	GTG North
31	KLU025-01b	H2-025-01b	Huntorf-Elsfleth 1 line, incl. M&R stations	GTG North
32	KLU027-01	H2-027-01	Sande-Jemgum line, incl. M&R stations	GTG North

No.	Core network ID	NDP ID	Network expansion measure	HTNO/HCNO
33	KLU029-01	H2-029-01	Huntorf-Rastede pipeline incl. M&R stations	GTG North
34	KLU030-01	H2-030-01	Oude Statenzijl-Folmhusen pipeline incl. M&R stations	GUD
35	KLU046-01	H2-046-01	Kolshorn-Sophiental line, incl. M&R stations	GUD
36	KLU092-01	H2-092-01	Ketzin-Buchholz pipeline incl. M&R stations	ONTRAS
37	KLU093-01	H2-093-01	Buchholz-Apollensdorf pipeline incl. M&R stations	ONTRAS
38	KLU094-01	H2-094-01	Bobbau-Großkugel pipeline incl. M&R stations	ONTRAS
39	KLU095-01	H2-095-01	Apollensdorf-Bobbau pipeline incl. M&R stations	ONTRAS
40	KLU096--01	H2-096-01	Großkugel-Schkeuditz pipeline incl. M&R stations	ONTRAS
41	KLU097-01a	H2-097-01a	Pipeline Schkeuditz-Plaußig incl. M&R stations	ONTRAS
42	KLU098-01	H2-098-01	Lüptitz-Cavertitz pipeline incl. M&R stations	ONTRAS
43	KLU099-01	H2-099-01	Hennickendorf-Vogelsdorf pipeline incl. M&R stations	ONTRAS
44	KLU100-01	H2-100-01	Vogelsdorf-Blumberg pipeline incl. M&R stations	ONTRAS
45	KLU102-01	H2-102-01	Wedringen-Wedringen pipeline incl. M&R stations	ONTRAS
46	KLU104-01	H2-104-01	Glöthe-Bernburg pipeline incl. M&R stations	ONTRAS
47	KLU105-01	H2-105-01	Bernburg-Preußlitz pipeline incl. M&R stations	ONTRAS
48	KLU106-01	H2-106-01	Bad Lauchstädt-Halle pipeline incl. M&R stations	ONTRAS
49	KLU108-01	H2-108-01	Milzau 1-Großkugel pipeline incl. M&R stations	ONTRAS
50	KLU110-01	H2-110-01	Leuna-Böhlen pipeline incl. M&R stations	ONTRAS
51	KLU111-01b	H2-111-01b	Leuna South-Nempitz pipeline incl. M&R stations	ONTRAS
52	KLU112-01	H2-112-01	Cavertitz-Mühlberg pipeline incl. M&R stations	ONTRAS
53	KLU123-01	H2-123-01	Coesfeld-Amelsbüren pipeline incl. M&R stations	Thyssengas H2
54	KLU124-01	H2-124-01	Amelsbüren-Rinkerode pipeline incl. M&R stations	Thyssengas H2

No.	Core network ID	NDP ID	Network expansion measure	HTNO/HCNO
55	KLU125-01	H2-125-01	Hohfeld-Ossenberg pipeline incl. M&R stations	Thyssengas H2
56	KLU126-01	H2-126-01	Wallach-Möllen pipeline incl. M&R stations	Thyssengas H2
57	KLU131-01	H2-131-01	Wallach-Xanten pipeline incl. M&R stations	Thyssengas H2
58	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 Appendix 1, complete with a justification for their omission.

Change of project names

The gas TSOs and operators of hydrogen transmission networks would like to point out that the names of the measureslisted 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 is 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 uniform company-specific technical standards and are only determined in subsequent project phases.

5

5 Security of supply review for methane for 2030

5.1 Introduction and approach

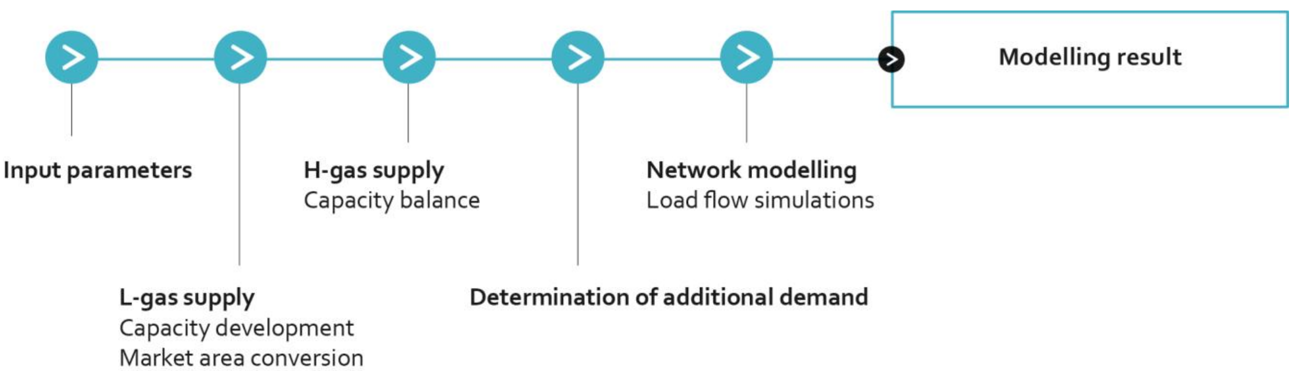
The comparison between trends towards declining methane demand in the long-term scenarios, some of which provide the basis for scenarios 1 to 3 approved by the BNetzA, and the increasing demand forecasts for methane underline the current level of uncertainty regarding future demand. In the draft Scenario 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.

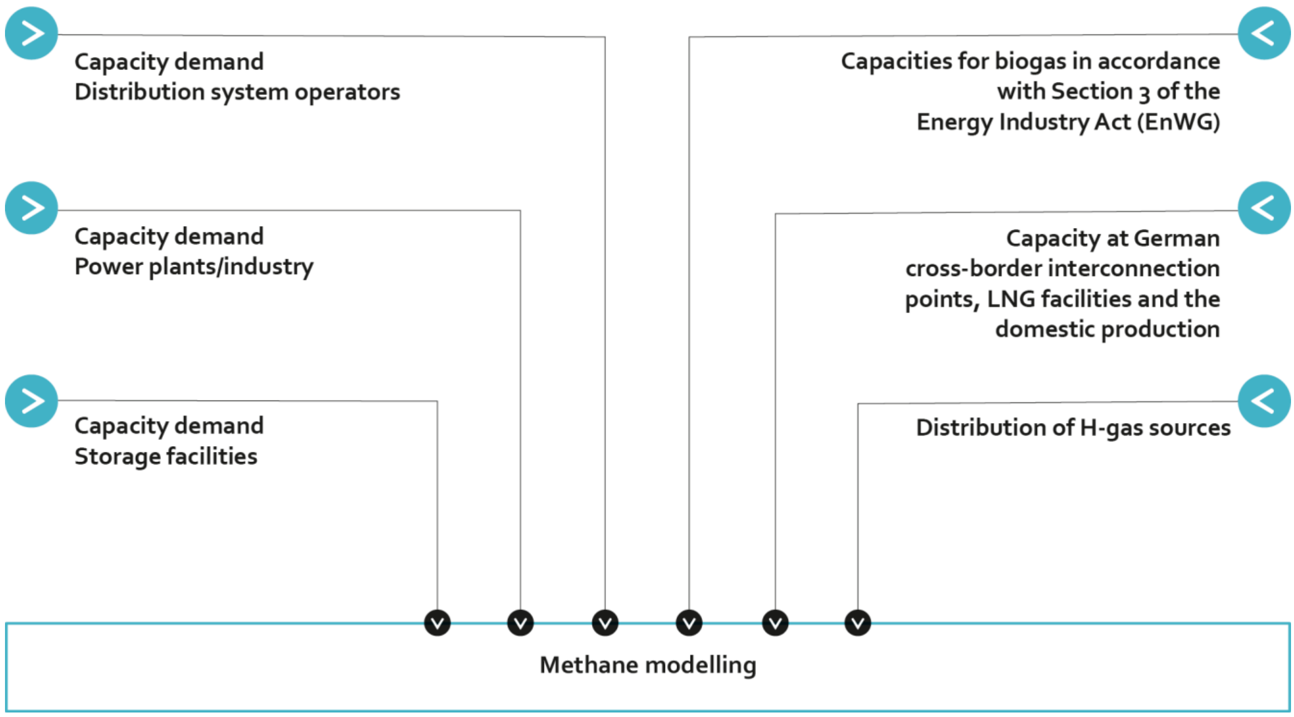
Figure 14: Basic approach to methane modelling 2030



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 1st 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 reductions.

5.2.1 Exit capacity

5.2.1.1 Power plants

According to the requirements specified by the Federal Network Agency (BNetzA), this scenario is based on all existing and newly planned methane-fired power plants with a total electrical output of 58 GWe 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 output of over 40 GWe (78 GWth) to be taken into account for power plants supplied via the gas transmission system. This includes the electrical output 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 GWe 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 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 for 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 1st 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 output of these fields has averaged around 320 MW in recent years. This output 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 feed-in atlas 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 output of 4 GWh/h for both areas.

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 2023/24 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.

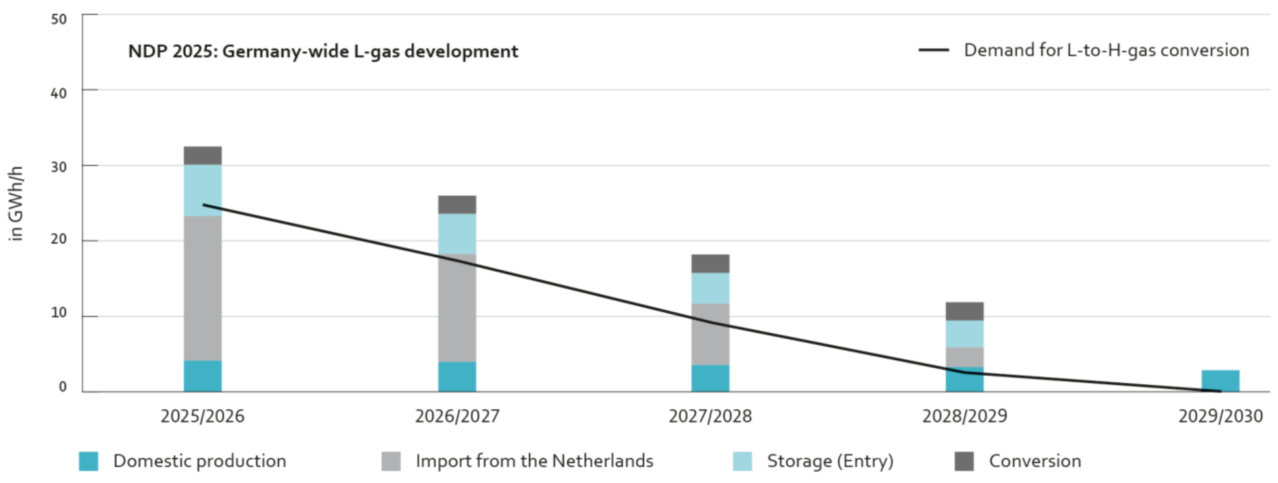
L-gas production in Germany is also declining. To counter these trends in domestic and foreign supplies, the gas transmission system operators are gradually converting the German network areas supplied with L-gas to H-gas. Since the start of the L-to-H-gas conversion in 2015, a total of around 3.6 million 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 2028/29, 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 2029/30, 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

Table13: Germany-wide L-gas capacity development

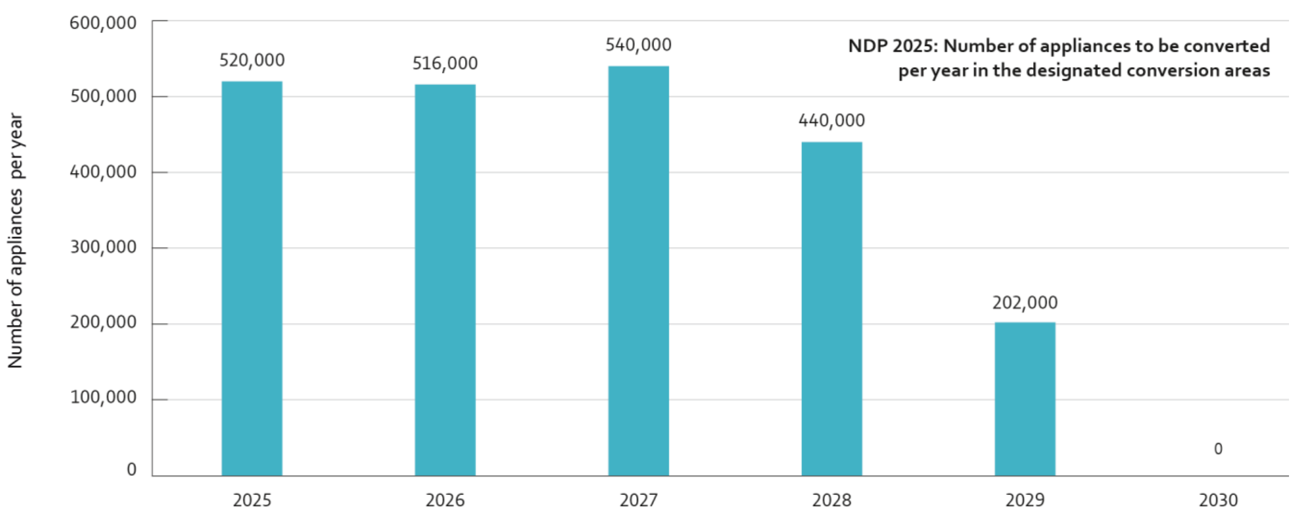
	Domestic production	Imports from NL	Storage entries	Conversion	Total gas available	L-gas demand	L-gas demand w/o L-to-H-gas conversion
	GWh/h						
2025/26	4.1	19.1	6.8	2.4	32.4	24.7	32.2
2026/27	3.9	14.3	5.3	2.4	25.9	17.3	33.1
2027/28	3.5	8.1	4.1	2.4	18.1	9.1	32.9
2028/29	3.2	2.6	3.6	2.4	11.7	2.5	32.7
2029/30	2.8	0.0	0	0.0	2.8	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 2.

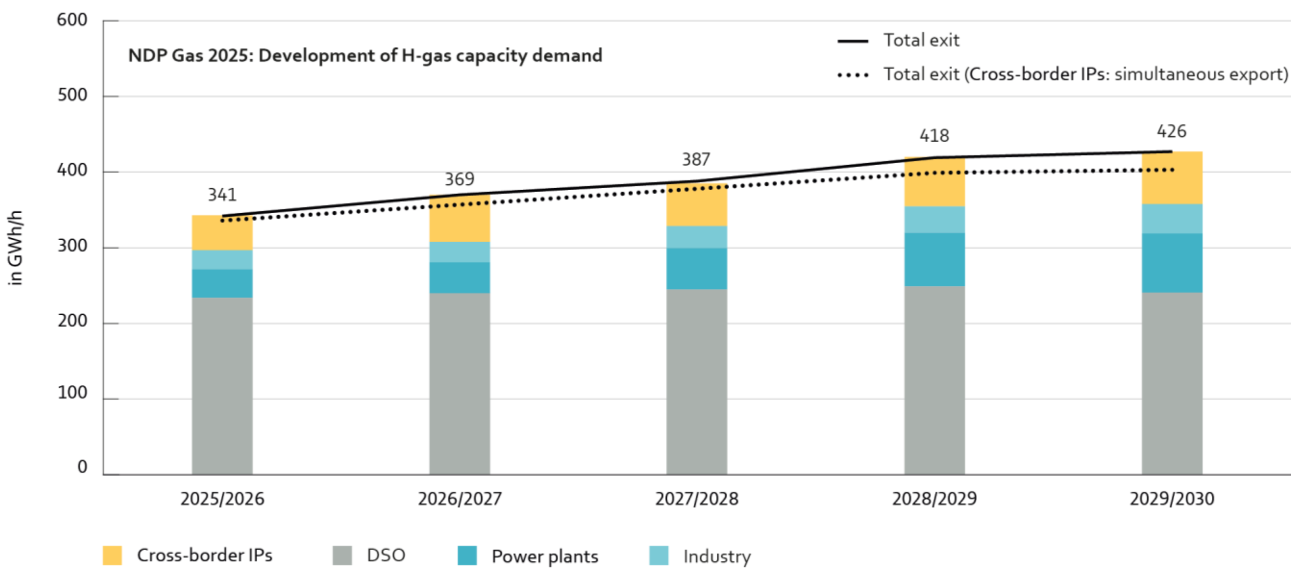
5.4 H-gas capacity balance until 2030

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 reductions 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 14.

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

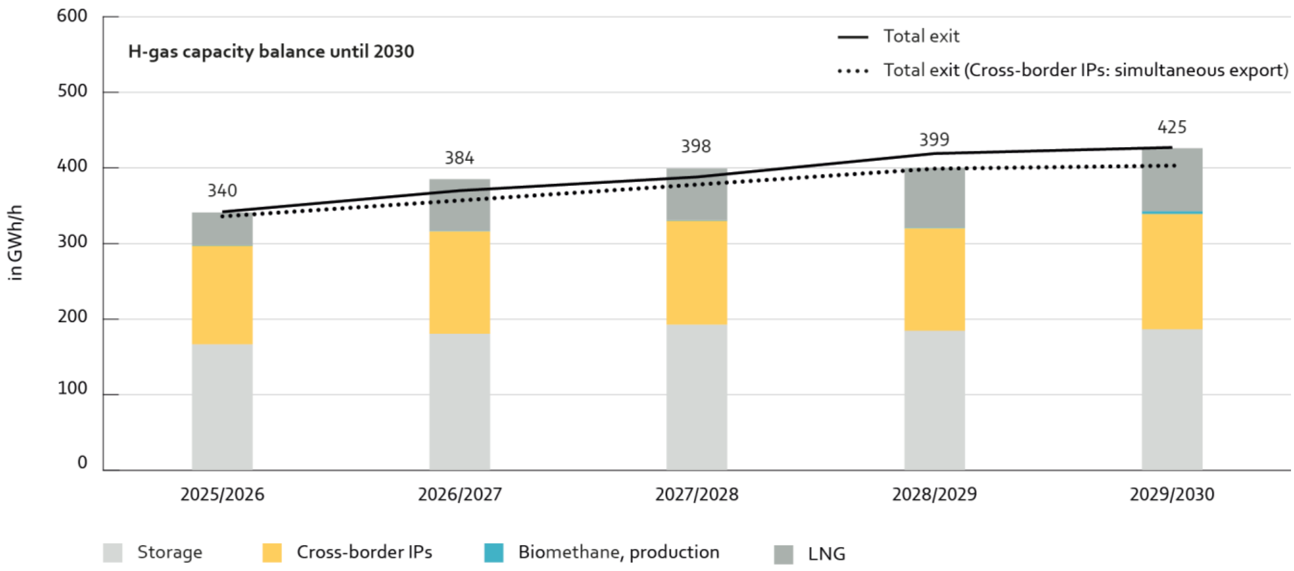
	Cross-border IPs	DSOs	Power plants	Industry	Total exits	Total exits (cross-border IPs: simultaneous export)
	GWh/h					
2025/26	46	233	38	25	341	335
2026/27	62	239	41	27	369	352
2027/28	59	244	55	29	387	370
2028/29	65	248	71	35	418	398
2029/30	69	240	78	39	426	402

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 15: Data on the H-gas capacity balance until 2030

	Storage	Cross-border IPs	LNG	Biomethane production	Total entries	Total exits	Undersupply (+)/ Oversupply (-)
	GWh/h						
2025/26	166	130	43	1	340	341	1
2026/27	180	135	68	1	384	369	-15
2027/28	192	137	68	1	398	387	-11
2028/29	184	135	79	1	399	418	19
2029/30	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 feed-in network operators. 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 2025/26 to 2027/28 and is even exceeded.

In GY 2028/29, 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 2026/27 and 2029/30 will actually occur or will be delayed to such an extent that the additional entry capacities expected from GY 2029/30 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 South-Eastern 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 negative planning scenario 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 initial 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 16: Results of the security of supply review for scenario 4

Scenario 1 results for the year 2037*	**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	1
- 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 values

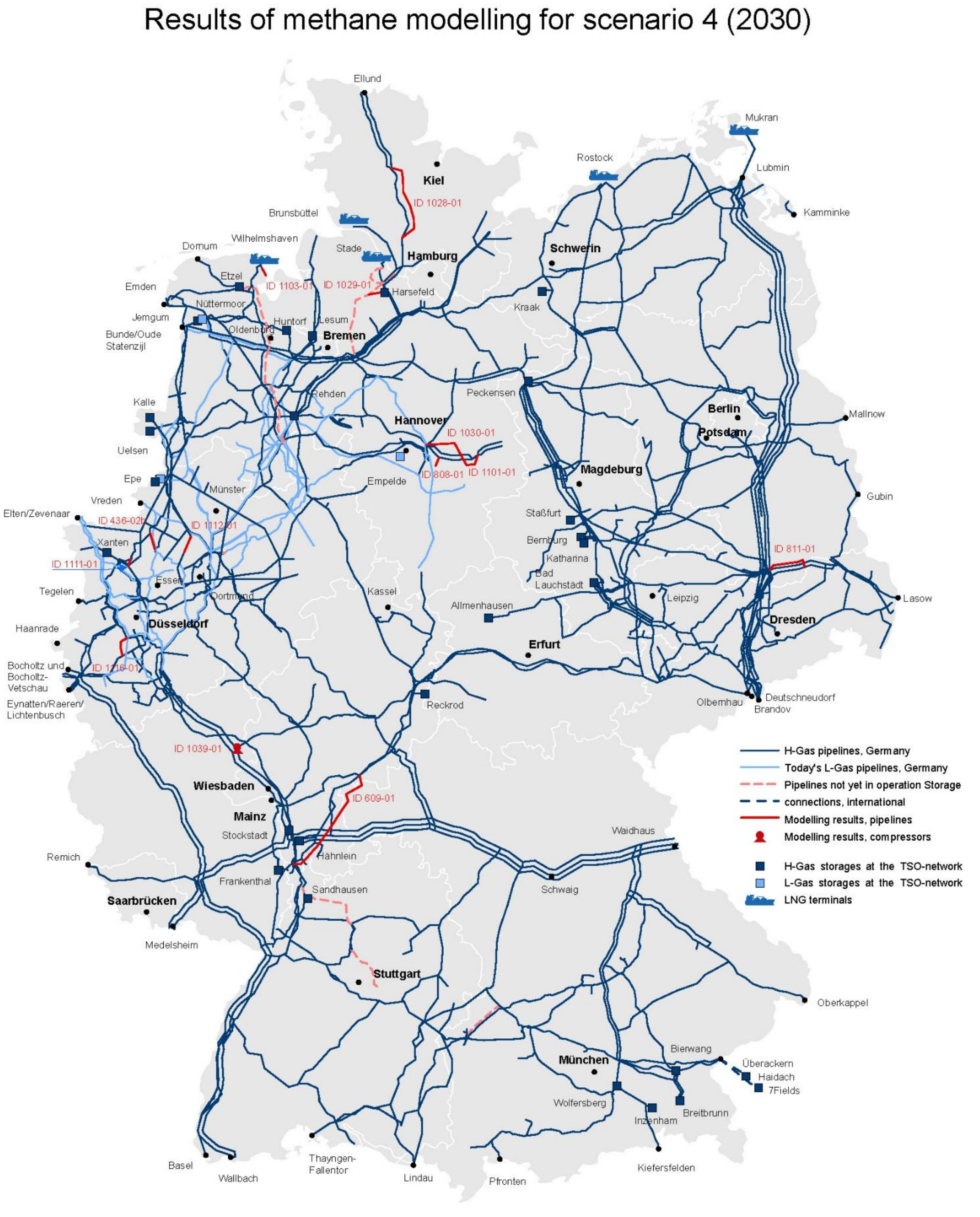
Source: Coordination Office for Gas and Hydrogen Network Development Planning

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.

For the conversion of dynamically allocable capacities (DAC) and conditionally firm, freely allocable capacities (cFAC) capacities to freely allocable capacities (FAC) in northern Germany, the gas transmission system operators refer to the revised draft of the Gas and Hydrogen Network Development Plan 2025. This includes the modelling results for the required MBIs. 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: Results of methane modelling 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.**. In the present draft of the Gas and Hydrogen Network Development Plan 2025, the results are presented for the modelling year 2037 for both methane and hydrogen. For procedural reasons, the results for methane in the modelling year 2045 are first presented in chapter 6.3. The results of the hydrogen modelling will be included in the revised draft of the Gas and Hydrogen Network Development Plan 2025, which will be made available for consultation by the BNetzA in the subsequent process. Chapter 6.4 provides an outlook on hydrogen modelling for the reference year 2045.

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). As a result, 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

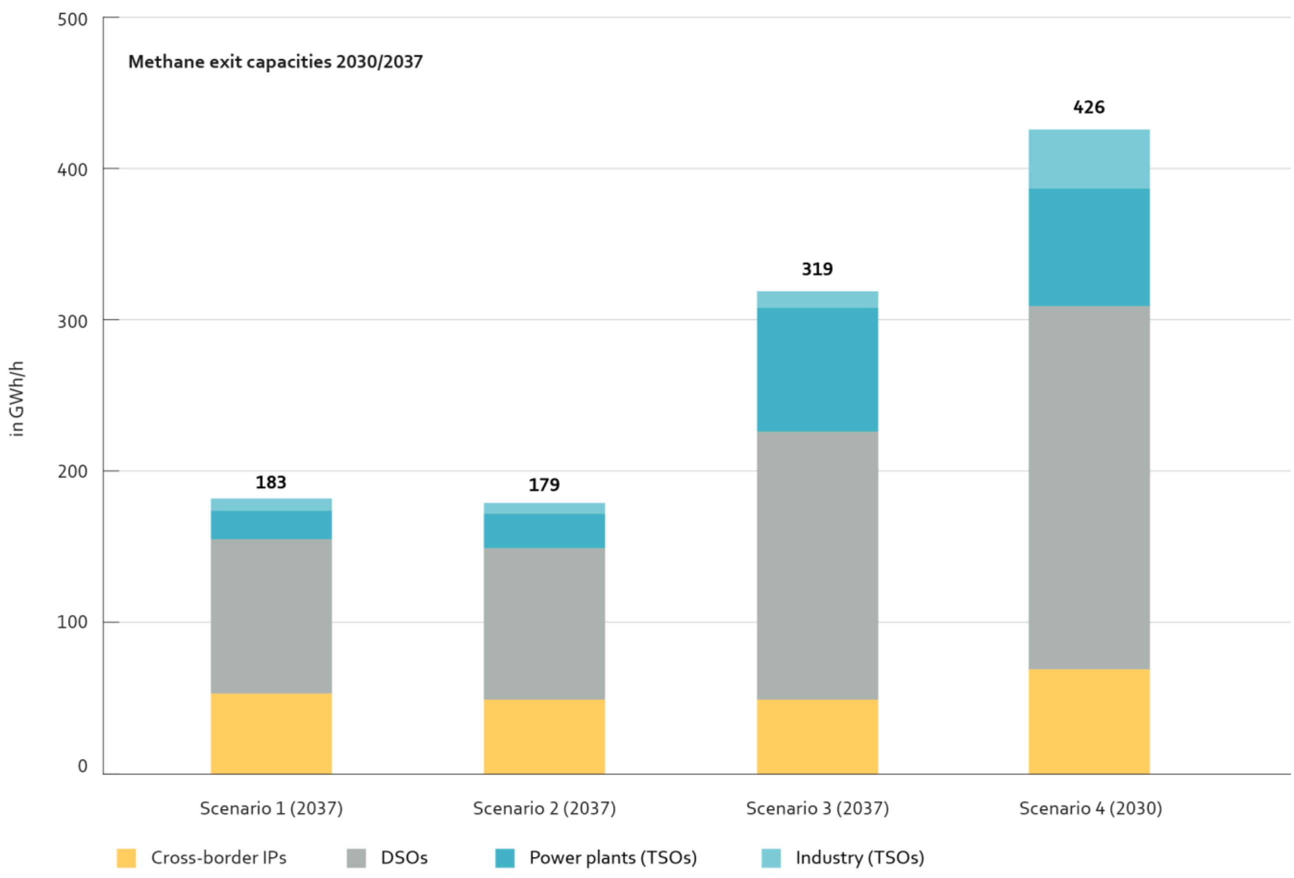
For classification and better comparability of the peak load situations in scenarios 1–3 in 2037, which are characterised by a significant decline in demand for exit capacity in some cases, the capacity demand of scenario 4 (2030) is additional presented below.

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 ("2025 – NDP 1st Draft" cycle), 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 ("2025 – NDP 1st draft" cycle).
- Distribution system operators are included in accordance with chapter 3.3.1.3. Capacities are published in the Gas NDP database ("2025 – NDP 1st draft" 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 ("2025 – NDP 1st Draft" cycle) 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, with the exception of 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 17: 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:

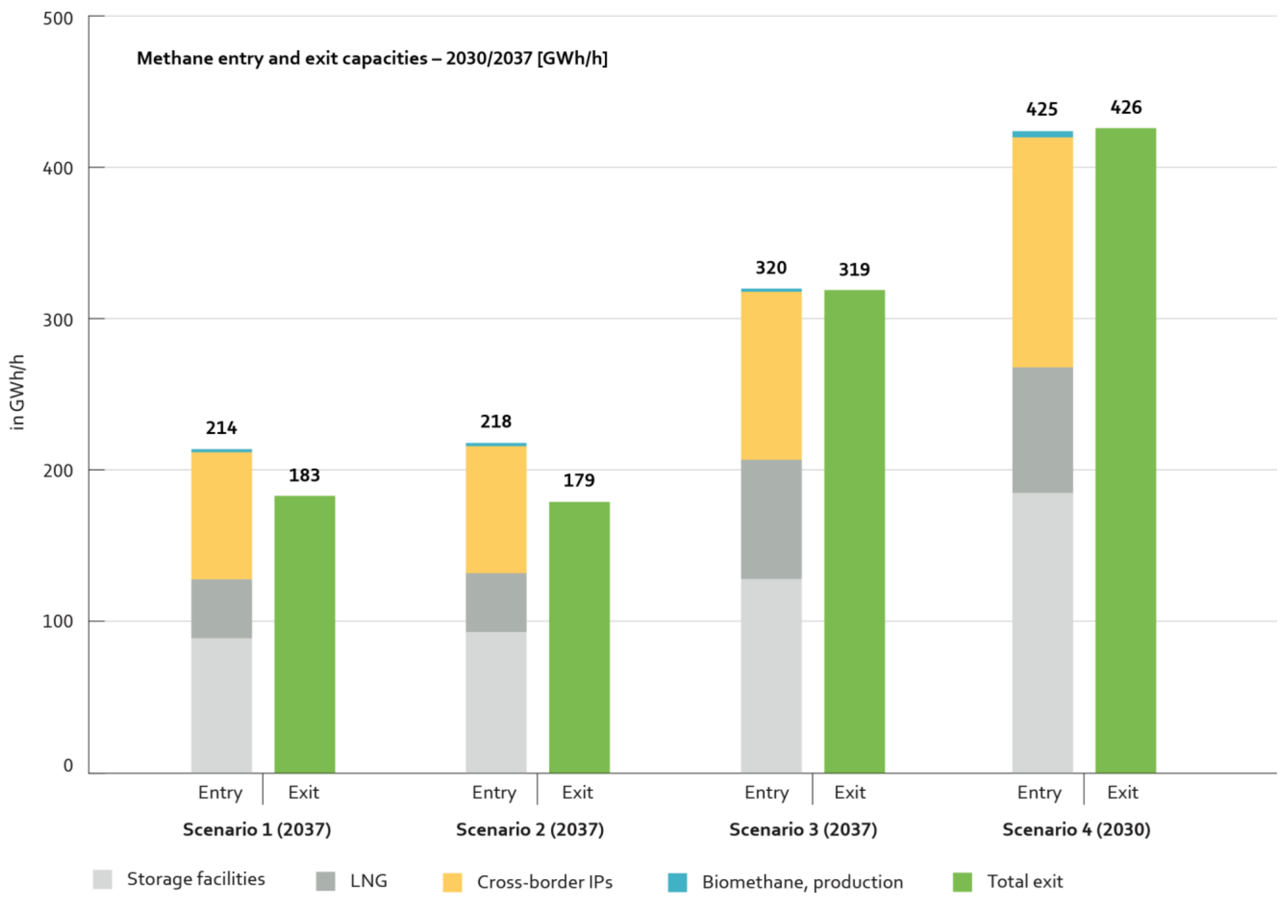
Scenarios 1 and 2:

- 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 18: 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			
Biomethane, production	2	2	2	4
Storage	89	93	128	186
LNG	39	39	79	83
Cross-border IPs	84	84	111	152
Total entries	**214**	**218**	**320**	**425**
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 on the basis of 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 describes the basic approach to hydrogen modelling (e.g. regionalisation and load cases). The modelling process involves determining the necessary measures on the basis of different load cases in order 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. The hydrogen balances include the hydrogen projects in each scenario that are also connected to the hydrogen transmission network.

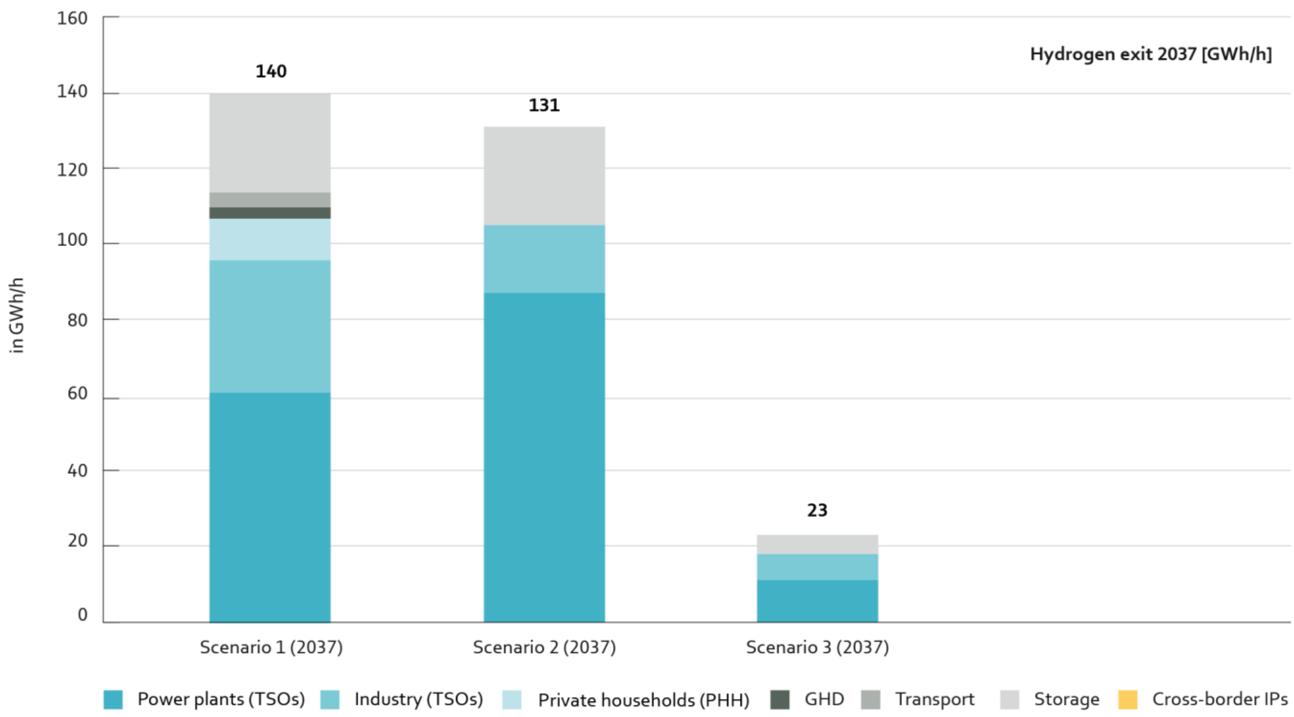
6.1.2.1 Hydrogen exit capacity demand

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 19: 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

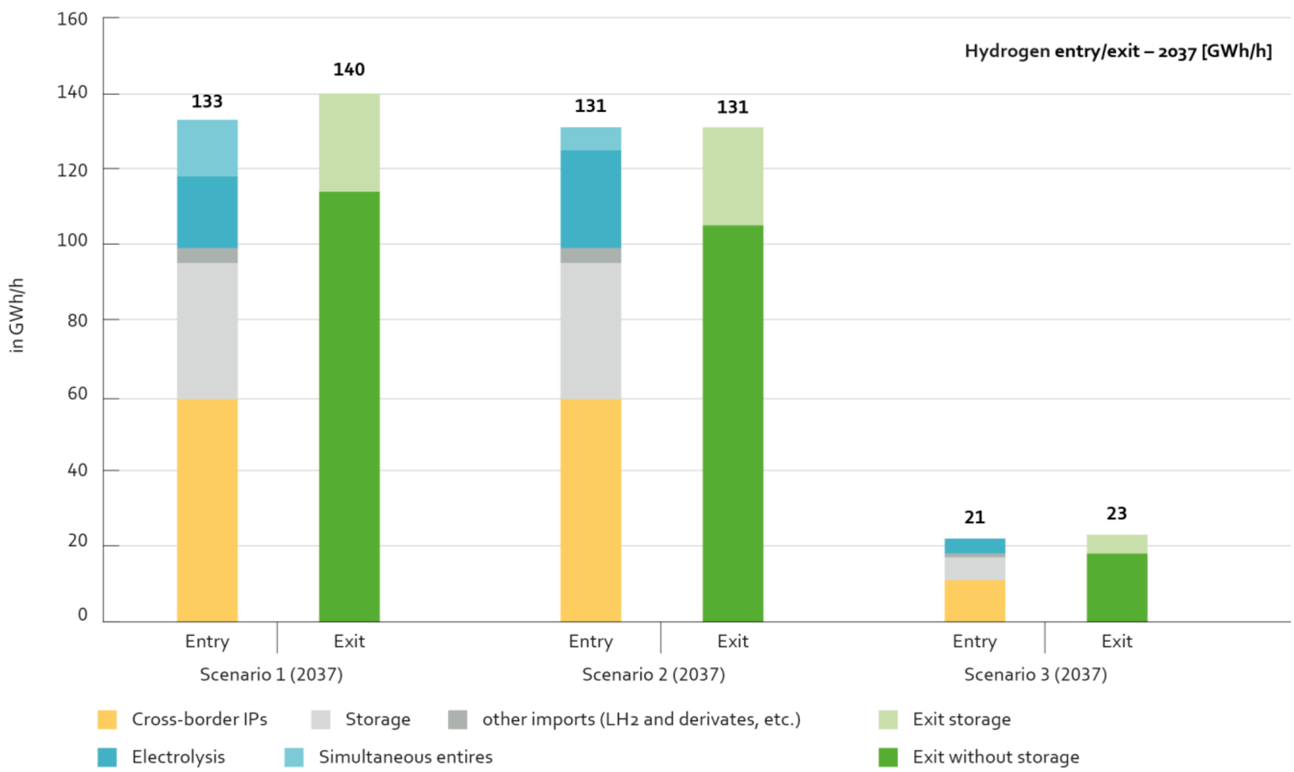
Scenario 1 shows the highest hydrogen demand. In this scenario, hydrogen is used in all sectors. In scenario 2, only exit capacities in the power plant and industry sectors are specified, with a different distribution than in scenario 1. Scenario 3 shows a delayed transition to hydrogen due to the overall 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 20: 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		
Cross-border IPs	59	59	11
Storage	36	36	6
Other projects (including LH_2 and derivatives)	4	4	1
Electrolysis	19	26	4
Additional entry capacity	15	6	—
Total entries	**133**	**131**	**21**

Hydrogen entry and exit capacities in 2037	**Scenario 1**	**Scenario 2**	**Scenario 3**
	GWh/h		
Storage exits	26	26	5
Exits without storage	114	105	18
Total exits	**140**	**131**	**23**

Source: Coordination Office for Gas and Hydrogen Network Development Planning

In the *Dark doldrums* load case, when all exit capacities (except storage) must be served, hydrogen withdrawn from storage is piped into the hydrogen transmission network. Figure 24 shows that in all scenarios, the entry capacity is greater than, or at least equal to, the exit capacity (without storage facilities).

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 21: 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	10.0	1.9
	Ellund	4.3	4.3	0.8
Norway/ UK	AquaDuctus (offshore)	5.0	5.0	0.9
	Dornum/ Emden	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
Belgium	Eynatten	3.8	3.8	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
Austria	Überackern	6.3	6.3	1.2
	Waidhaus	6.0	6.0	1.1

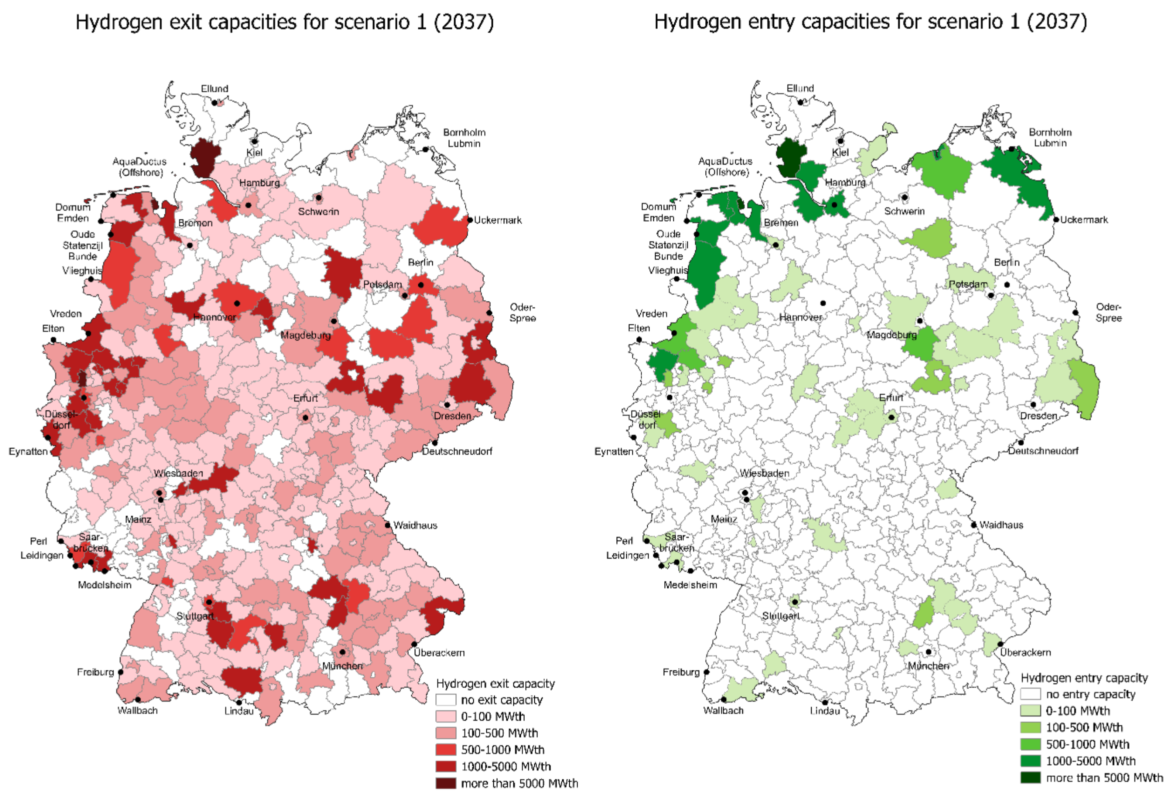
Country	Cross-border IPs	Scenario 1	Scenario 2	Scenario 3
		Entries [GWh/h]		
Czech Republic	Deutschneudorf	0.0	0.0	0
Poland	Oder-Spree	2	2	0.4
	Uckermark	0.8	0.8	0.2
Total		**58.6**	**58.6**	**10.7**

Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.1.2.4 Entry and exit capacities at district level

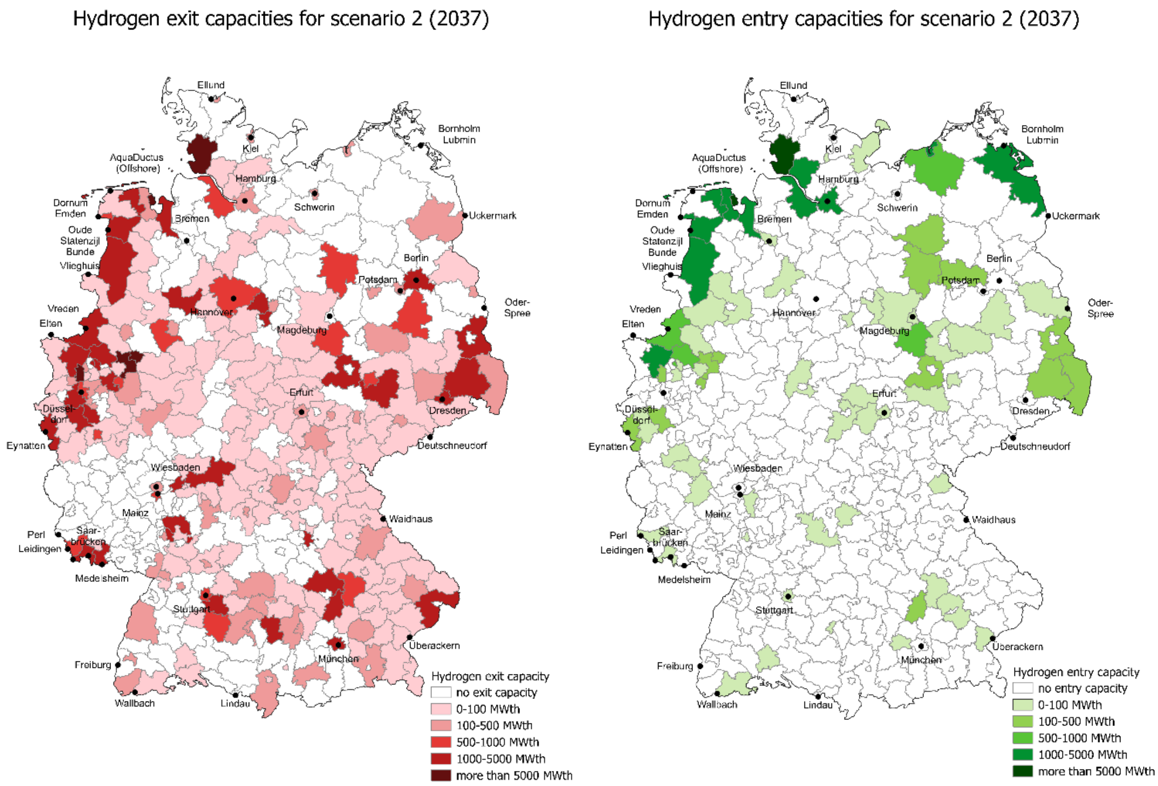
The following maps show the distribution of entry and exit capacities (excluding cross-border IPs) at district level.

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



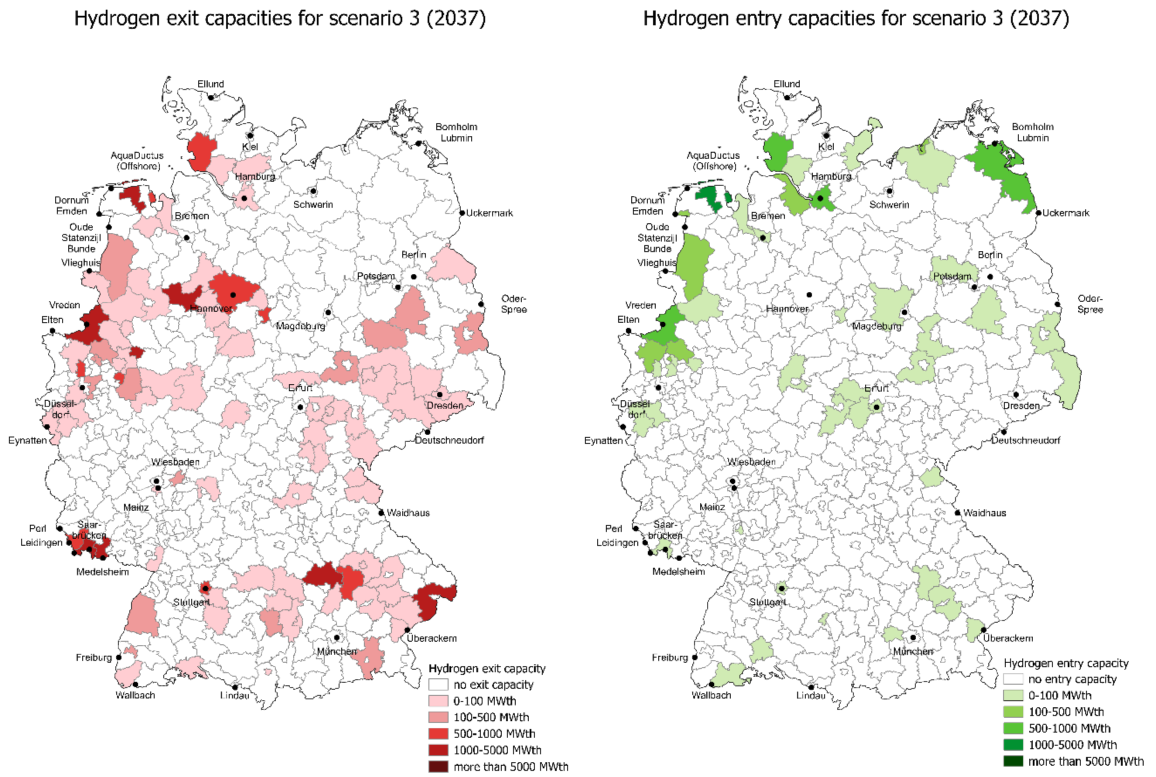
Source: Coordination Office for Gas and Hydrogen Network Development Planning

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 Results of methane and hydrogen modelling for the reference 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 6.2.1, 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 initial network (chapter 4.2) once the execution has reached an advanced stage. Where measures are not part of the initial 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. Projects in the power generation segment serve to connect power plants to the grid to help meet growing electricity demand, including that resulting from increasing electrification, while new construction 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 "Expansion measures" for both methane and hydrogen.

A detailed description of the M&R stations required for the hydrogen network cannot be provided at this stage, as some of the operatorship and network control matters are still unclear. The hydrogen transmission system operators have therefore provided an overview of all locations for potential M&R stations for each scenario in Annex 3. The M&R station costs are initially included as a percentage of the pipeline costs. For the revised draft of the Gas and Hydrogen Network Development Plan 2025, the M&R stations will be added to the Gas NDP database where possible.

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

6.2.1 Results of methane modelling 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 initial 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 the following Table 21 and in Figure 28.

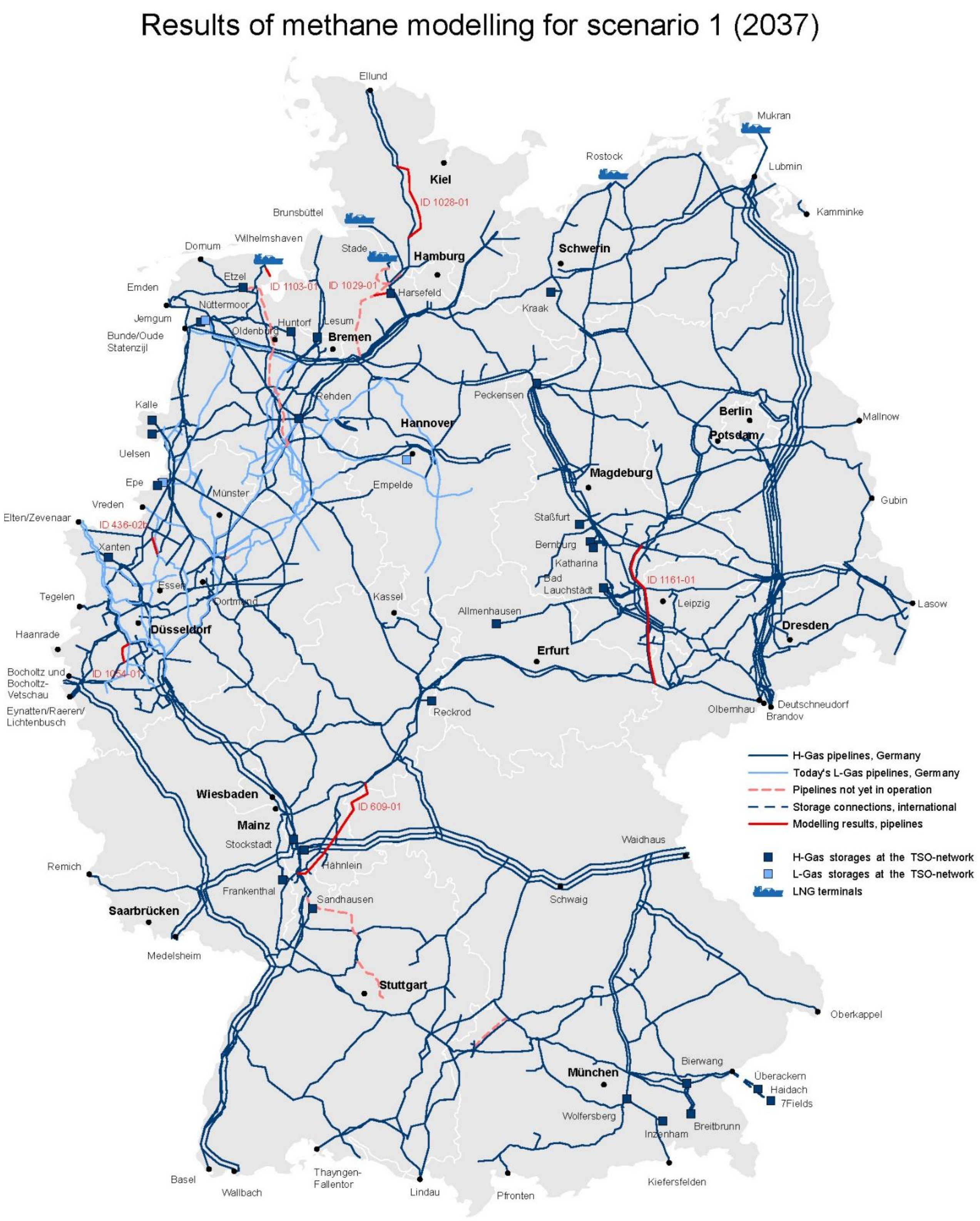
22: Results of methane modelling for scenario 1 (2037)

Results for scenario 1 for the year 2037*	By the end of 2037
Technical parameters	
Pipelines [km]	362
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 values

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 28: Results of methane modelling 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 23 and in Figure 29.

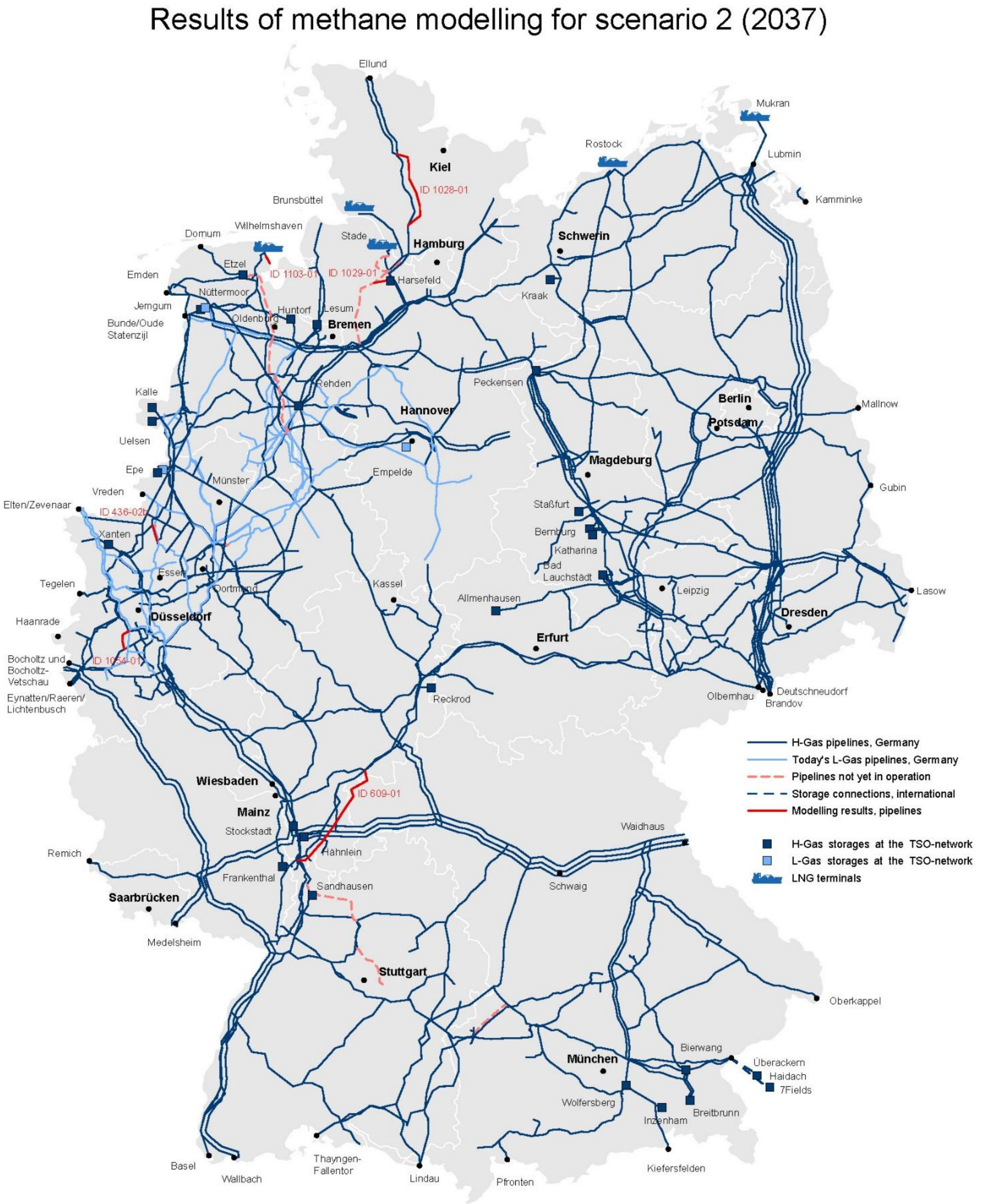
Table 23: Results of methane modelling for scenario 2 (2037)

Results for scenario 2 for the year 2037*	**By the end of 2037**
Technical parameters	
Pipelines [km]	242
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 values

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 29: Results of methane modelling 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 following Table 24 and in Figure 30.

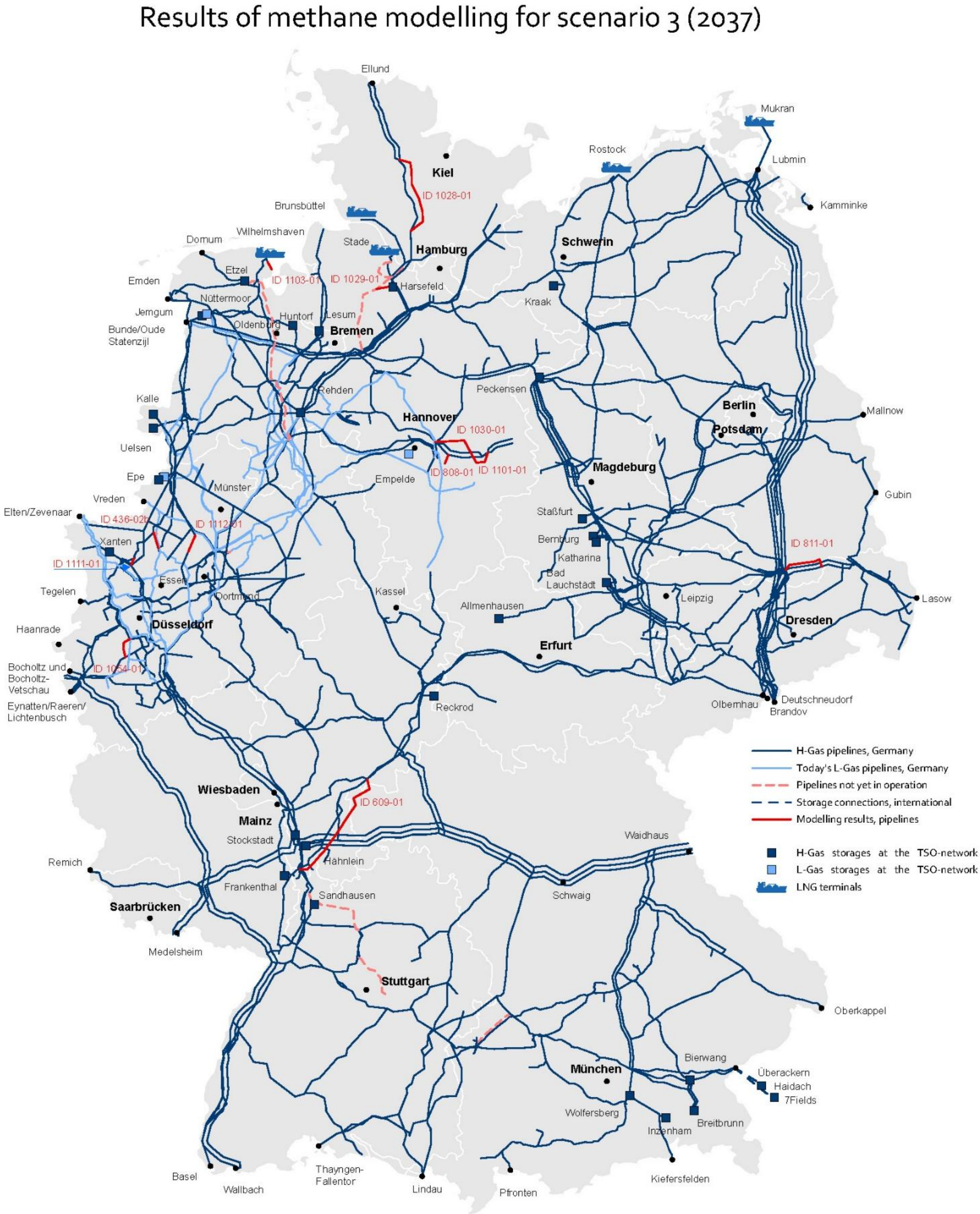
24: Results of methane modelling for scenario 3 (2037)

Results for scenario 3 for the year 2037*	By the end of 2037
Technical parameters	
Pipelines [km]	360
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 values

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 30: Results of methane modelling for scenario 3 (2037)



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.2.2 Results of hydrogen modelling 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 initial 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 results 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 25 and in Figure 31.

Table 25: Results of hydrogen modelling for scenario 1 (2037) and the hydrogen initial network

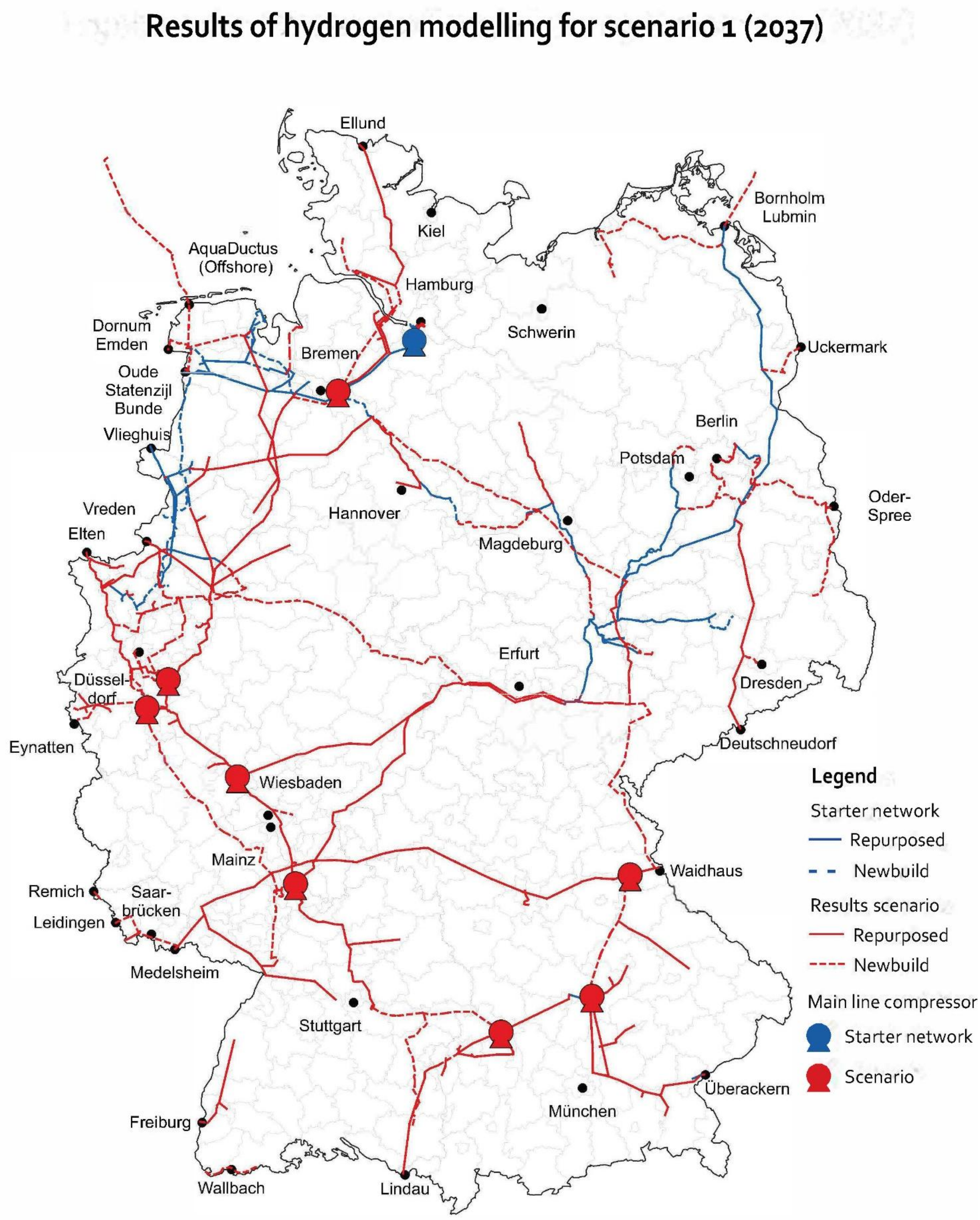
Results for scenario 1 for the year 2037*	Initial network	By the end of 2037	Initial network and results for scenario 1 for 2037
Technical parameters			
Compressor capacity [MW]	6	761	767
Pipelines [km]	2,199	8,226	10,425
- of which pipelines to be repurposed [km]	1,597	4,727	6,324
- of which newly built pipelines [km]	602	3,312	3,914
- of which newly built pipelines (offshore) [km]	0	186	186
- For information: Czech-German Hydrogen Interconnector (CGHI)** [km]		168	
Total investment [billion euros]	**4.1**	**25.5**	**29.6**
Compressor stations	0.1	5.2	5.3
Pipelines (incl. M&R station costs)	4.0	20.3	24.3
- of which pipelines to be repurposed	1.1	3.2	4.3
- of which newly built pipelines	2.9	15.2	18.1
- of which newly built pipelines (offshore)	0	1.9	1.9

* rounded values

** 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: Results of hydrogen modelling 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 26 and in Figure 32.

26: Results of hydrogen modelling for scenario 2 (2037) and the hydrogen initial network

Results for scenario 2 for the year 2037*	Initial network	By the end of 2037	Initial network and results for scenario 2 for 2037
Technical parameters			
Compressor capacity [MW]	6	520	526
Pipelines [km]	2,199	7,944	10,193
- of which pipelines to be repurposed [km]	1,597	4,514	6,111
- of which newly built pipelines [km]	602	3,294	3,896
- of which newly built pipelines (offshore) [km]	0	186	186
- For information: Czech-German Hydrogen Interconnector (CGHI)** [km]		168	

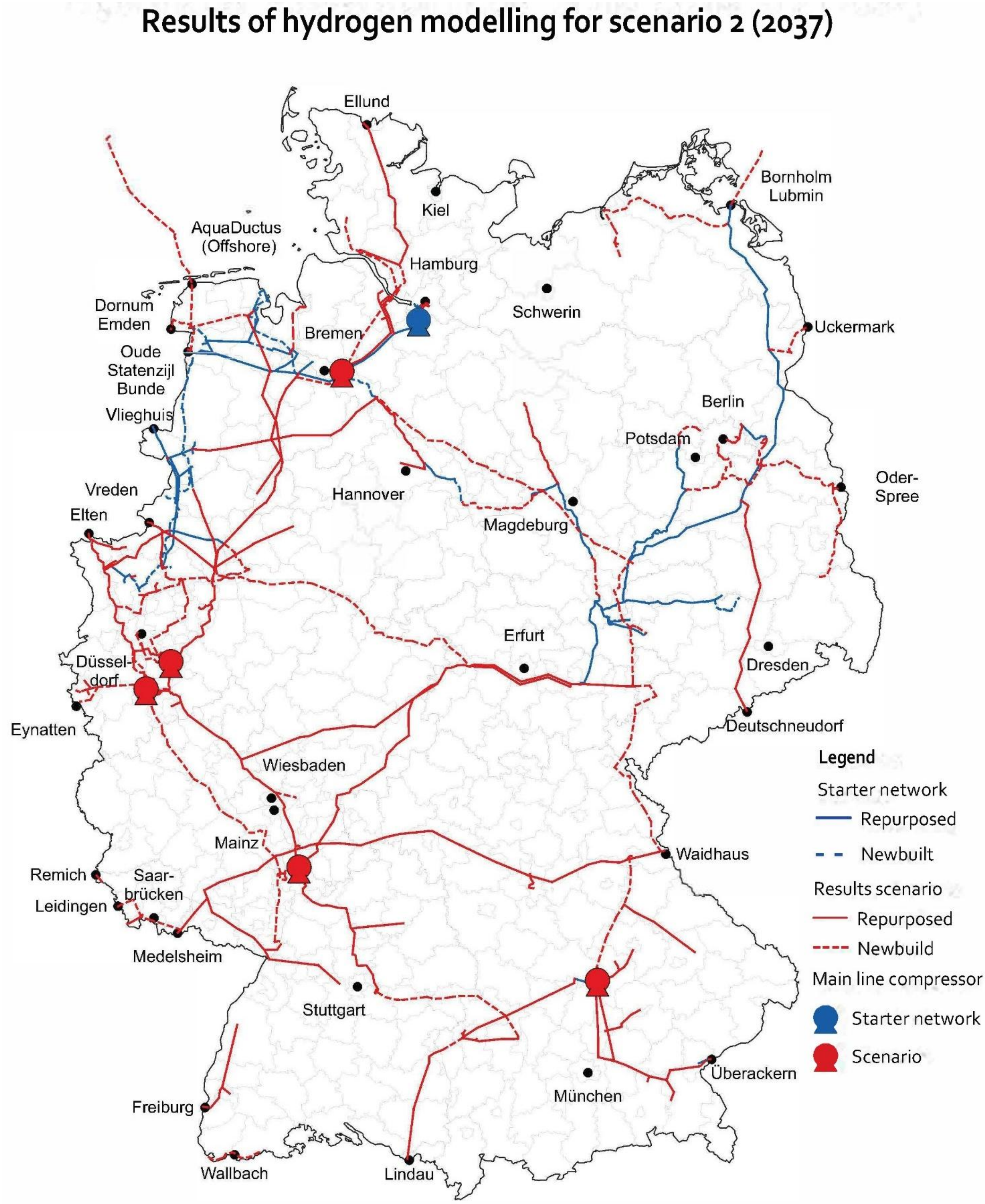
Total investment [billion euros]	**4.1**	**23.8**	**27.9**
Compressor stations	0.1	3.7	3.8
Pipelines (incl. M&R station costs)	4.0	20.1	24.1
- of which pipelines to be repurposed	1.1	3.1	4.2
- of which newly built pipelines	2.9	15.1	18.0
- of which newly built pipelines (offshore)	0	1.9	1.9

* rounded values

** 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: Results of hydrogen modelling 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 27 and in Figure 33.

27: Results of hydrogen modelling for scenario 3 (2037) and for the hydrogen initial network

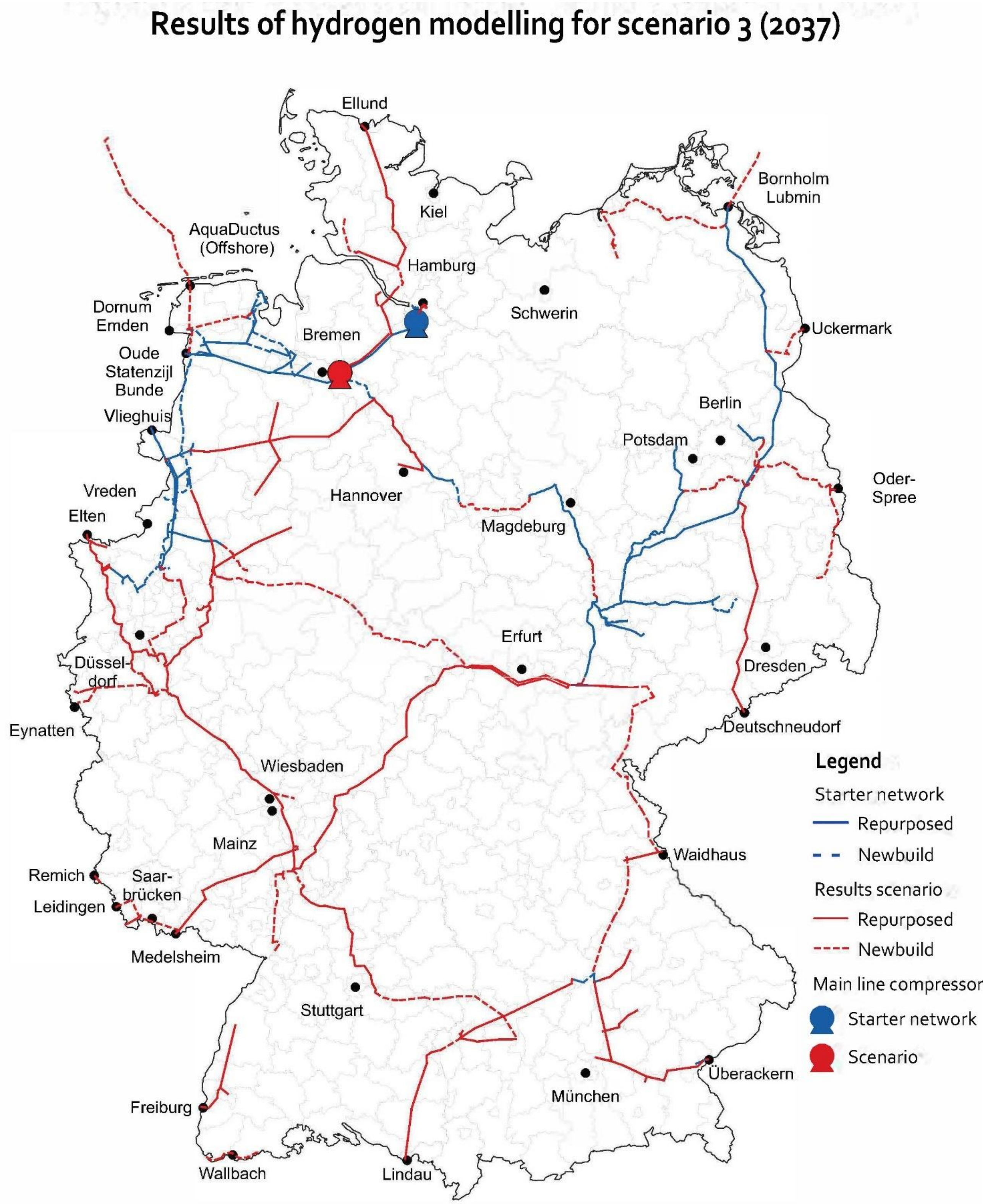
Results for scenario 3 for the year 2037*	Initial network	Scenario 3 2037	Initial network and results for scenario 3 for 2037
Technical parameters			
Compressor capacity [MW]	6	8	14
Pipelines [km]	2,199	5,229	7,428
- of which pipelines to be repurposed [km]	1,597	2,956	4,553
- of which newly built pipelines [km]	602	2,087	2,689
- of which newly built pipelines (offshore) [km]	0	186	186
- For information: Czech-German Hydrogen Interconnector (CGHI)** [km]	168		
Total investment [billion euros]	**4.1**	**13.1**	**17.2**
Compressor stations	0.1	0.1	0.2
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	1.9	1.9

* rounded values

** 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: Results of hydrogen modelling 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 network operators to determine the pipelines that can be repurposed for the hydrogen transmission network in scenario 2 on the basis of 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 operators of hydrogen transmission networks 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 28 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 28: 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
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
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

6.3 Results of methane modelling 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 GWe.

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 Sections 38 and 39 of the GasNZV (German Gas Supply Ordinance), as in Table 29.
- 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 29: Power plant sites and gas connection ratings considered in scenario 3 (2045)

No.	Name of point/zone	Scenario 3 (2045) [MWe]*	Scenario 3 (2045) [MWth]
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

No.	Name of point/zone	Scenario 3 (2045) [MWe]*	Scenario 3 (2045) [MWth]
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
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.

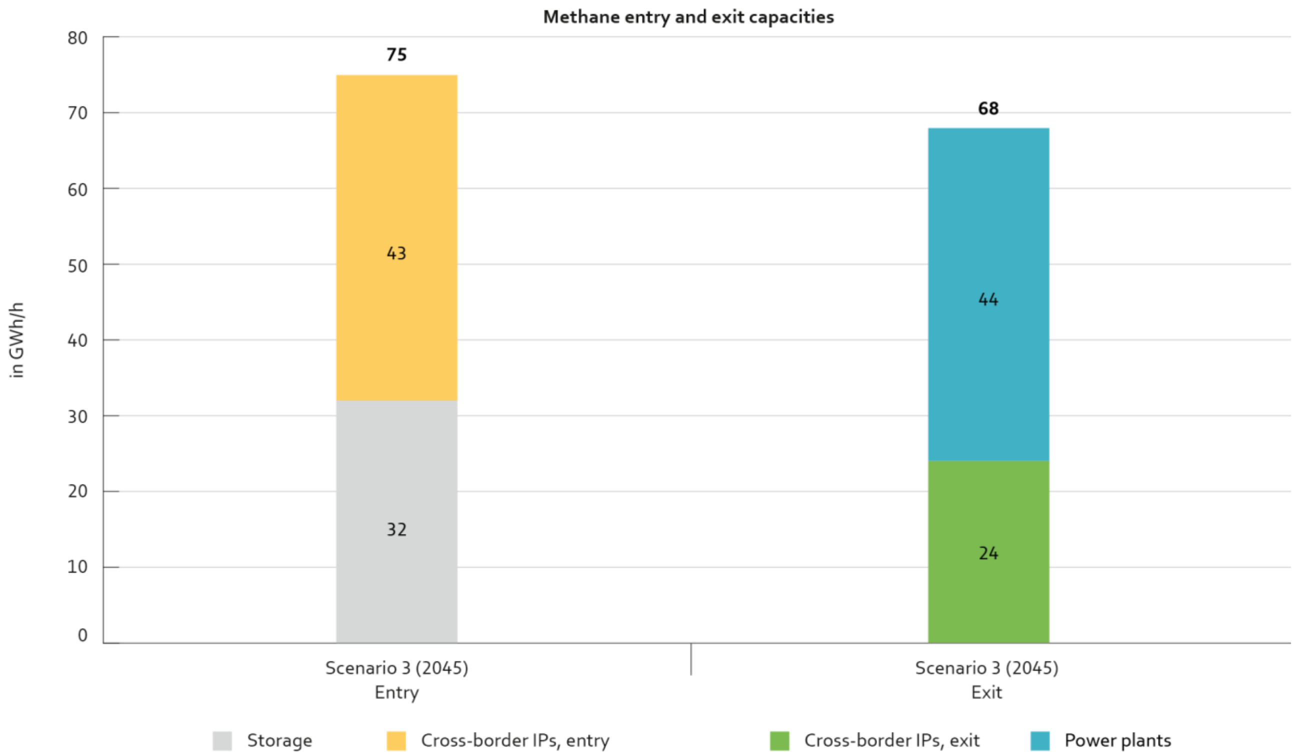
6.3.1.3 Resulting entry capacities in the balancing case

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 Table 29, 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.

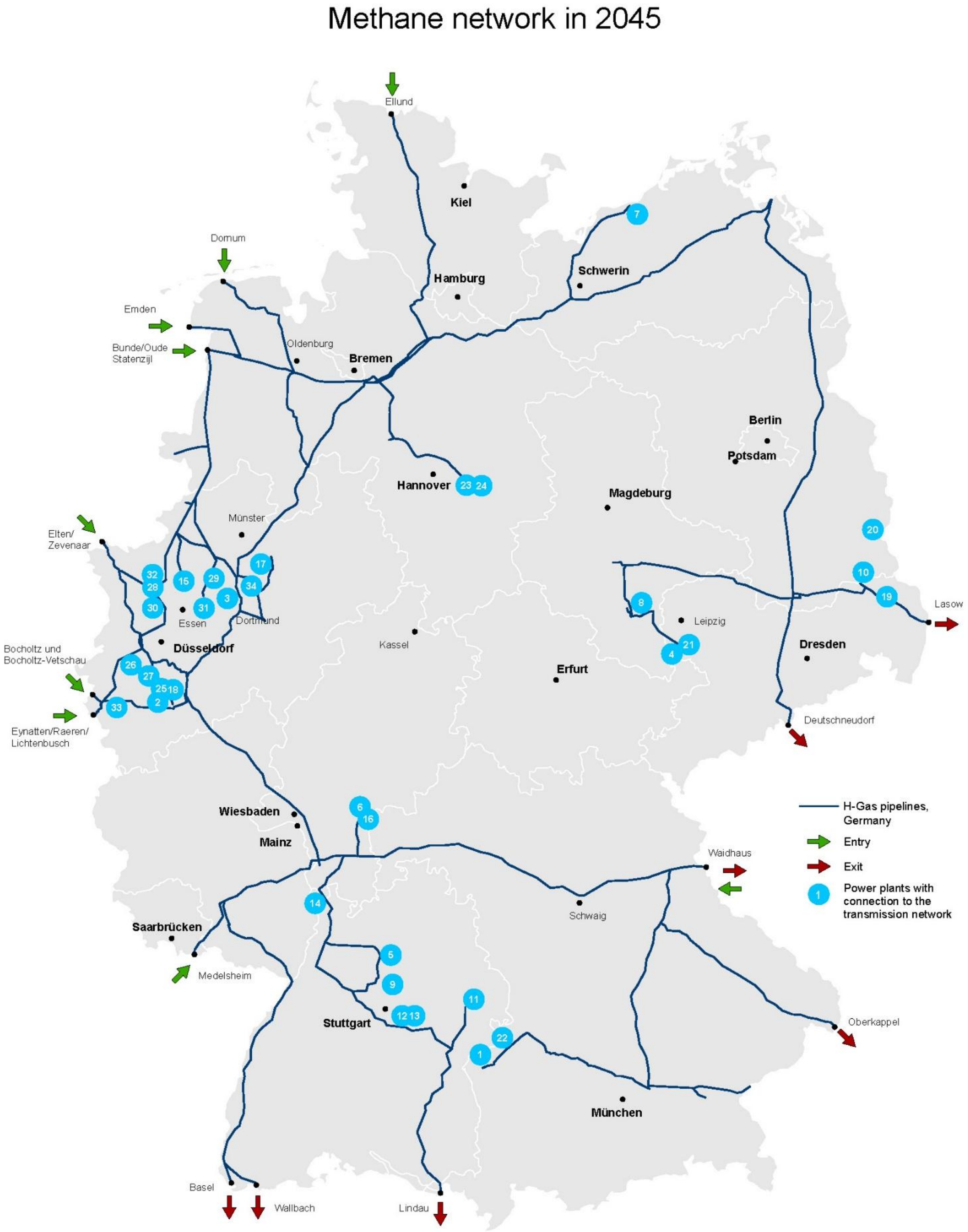
With connections to Norway, Denmark, the Netherlands, Belgium and France via cross-border IPs, several import options are available, which also ensures the resilience of the network in terms of security of supply.

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 4. The following figure is a graphical representation of the methane network in 2045. The power plants included are numbered according to Table 29.

35: Methane network in 2045



Source: Coordination Office for Gas and Hydrogen Network Development Planning

6.4 Outlook for hydrogen modelling in 2045

In the modelling year 2045, a significant portion of today's methane pipeline will no longer be needed for methane and could in principle be available for conversion to hydrogen. In order to ensure efficient and process-optimised modelling of both energy sources, the operators of hydrogen transmission networks first determine the methane network in 2045 needed to fulfil the given transport task. This makes it clear from the outset which methane infrastructure is available for conversion to hydrogen and hence for hydrogen network modelling.

The development of a hydrogen infrastructure is central to achieving long-term climate targets, which is why the gas TSOs and operators of hydrogen transmission networks are already providing an outlook on the development of the hydrogen network up to 2045 in the draft Gas and Hydrogen Network Development Plan 2025 and outlining the next steps.

In all three scenarios, hydrogen demand will increase significantly by 2045 compared to 2037. Against this backdrop, it is to be expected that there will be a significantly higher demand for hydrogen infrastructure in 2045 compared to 2037.

The gas TSOs and operators of hydrogen transmission networks generally intend to build on the results of the 2037 modelling. Scenarios 1 and 2 assume no relevant methane demand in 2045, and methane demand also declines significantly in scenario 3. This gives a number of additional pipelines that are currently used for methane but will be available for hydrogen in 2045. The task of the gas TSOs and operators of hydrogen transmission networks was to identify those pipelines that can help to meet the increased transportation demand in 2045, and they first used pipelines with a diameter of DN 400 or more for the hydrogen modelling. Next, available methane pipelines with smaller diameters were examined to see whether they could be used for the hydrogen network. In addition to the larger pipelines shown in the following figure, other pipelines could be used to serve additional regions. Moreover, several newly built pipelines have already been added to allow a meaningful development of further sources of supply, such as cross-border IPs. A uniform starting point for modelling has been assumed for all three scenarios. Consequently, the pipelines required in scenario 3 for methane in 2045 (chapter 6.3.2) are not taken into account in any of the three scenarios at the start of modelling.

The following Figure 36 shows the starting point for hydrogen modelling in 2045, differentiating between the hydrogen network for 2037 and 2045. The pipelines for 2037 represent the hydrogen modelling results for scenarios 1–3. Additional potential hydrogen pipelines are shown for 2045 (cf. Annex 5).

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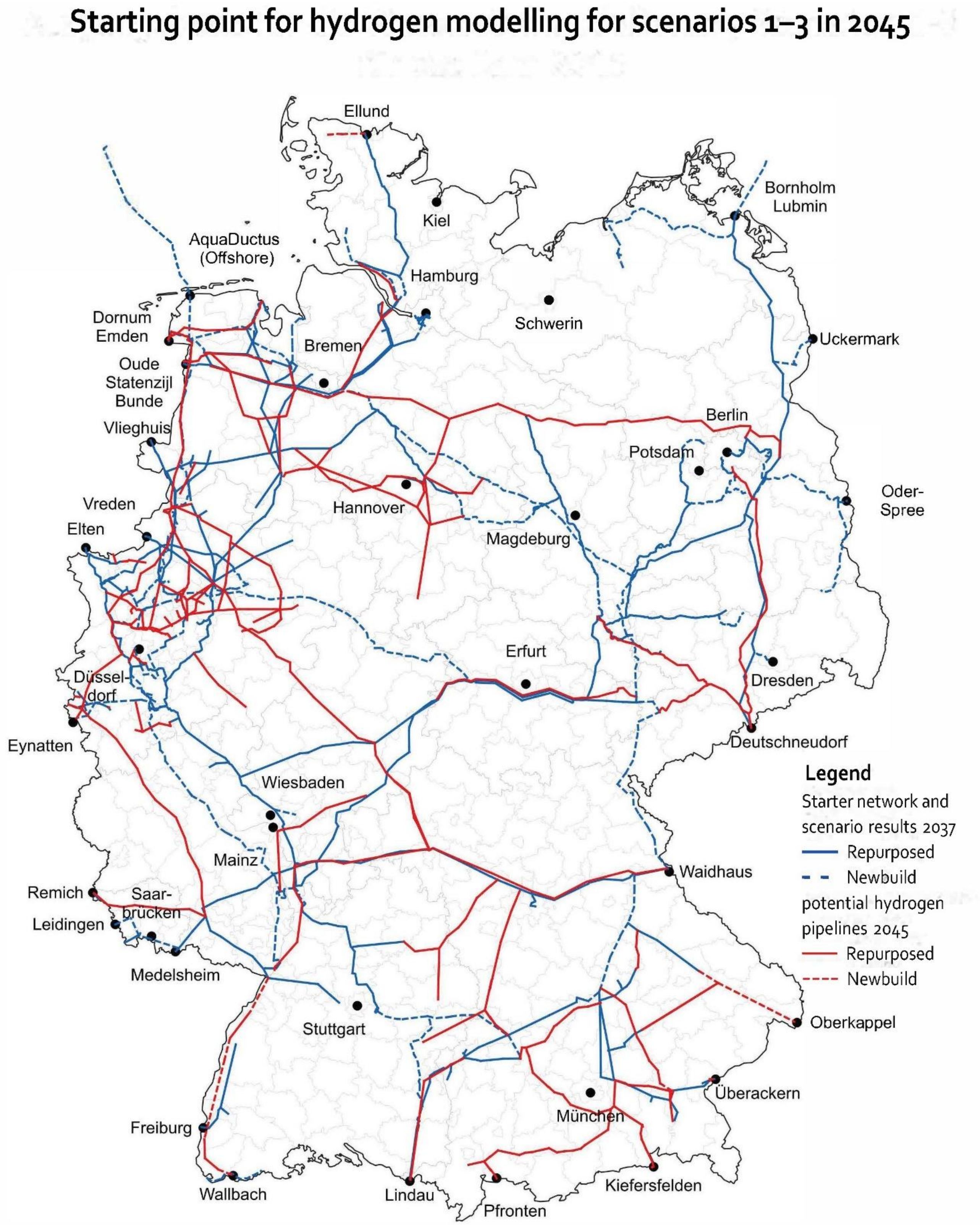
Figure 36: Starting point for hydrogen modelling for scenarios 1–3 in 2045



Source: Coordination Office for Gas and Hydrogen Network Development Planning

In total, hydrogen modelling for 2045 starts with a potential pipeline network of around 6,250 kilometres. The process for regionalising the hydrogen demand specified for Germany is described in chapter 3.4. As part of the modelling for 2045, the operators of hydrogen transmission networks will examine which pipelines and compressor capacities are required to meet demand.

Due to the significant increase in demand described above, the modelling process also needs to identify a significant increase in hydrogen entry capacities. The minimum entry capacities specified in the approved Scenario Framework by the BNetzA will not be sufficient to meet hydrogen demand, which is why the import of hydrogen across borders will play a central role here. In addition, the transmission network operators will draw on further additional hydrogen feed-in projects reported as part of the market survey to meet demand.

From the perspective of operators of hydrogen transmission networks, 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 results, which will be incorporated into the revised draft of the Gas and Hydrogen Network Development Plan 2025, 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.

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 operators of hydrogen transmission networks 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 measuresthat 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 30 and Figure 37 and takes account of the above criteria. The relevant methane projects are set out in Annex 6.

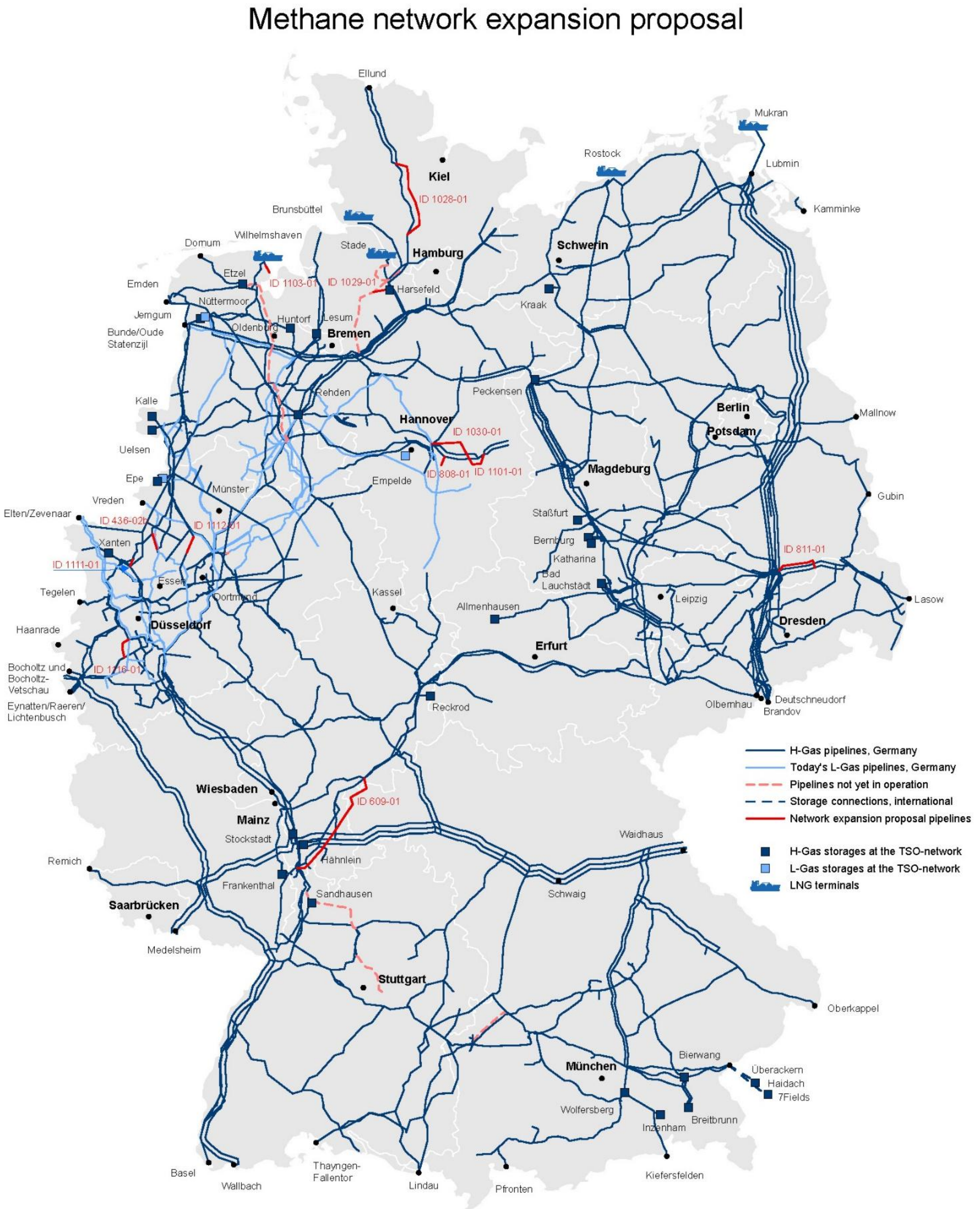
Table 30: Methane network expansion proposal

Results of methane network expansion proposal	
Technical parameters	
Pipelines [km]	364
Compressor capacity [MW]	0
Total investment [billion euros]	**2.9**
- of which network expansion measures from NDP 2022	1
- 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 values

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Figure 37: 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 new construction measures 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 new construction measures 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 by 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.

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 operators of hydrogen transmission networks 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, by defining implementation roadmaps.

The hydrogen network expansion proposal is presented in Table 31 and Figure 38 and takes account of the above criteria. The relevant hydrogen projects are set out in Annex 7.

Table 31: Hydrogen network expansion proposal

Results of hydrogen network expansion proposal*	
Technical parameters	
Compressor capacity [MW]	255
Pipelines [km]	7,007
- of which pipelines to be repurposed [km]	3,685
- of which newly built pipelines [km]	3,163
- of which newly built pipelines (offshore) [km]	186
- For information: Czech-German Hydrogen Interconnector (CGHI)** [km]	168
Total investment [billion euros]	**20.1**
Compressor stations	1.9
Pipelines (including costs for maintenance and repair stations)	18.2
- of which pipelines to be repurposed	2.5
- of which newly built pipelines	13.9
- of which newly built pipelines (offshore)	1.9

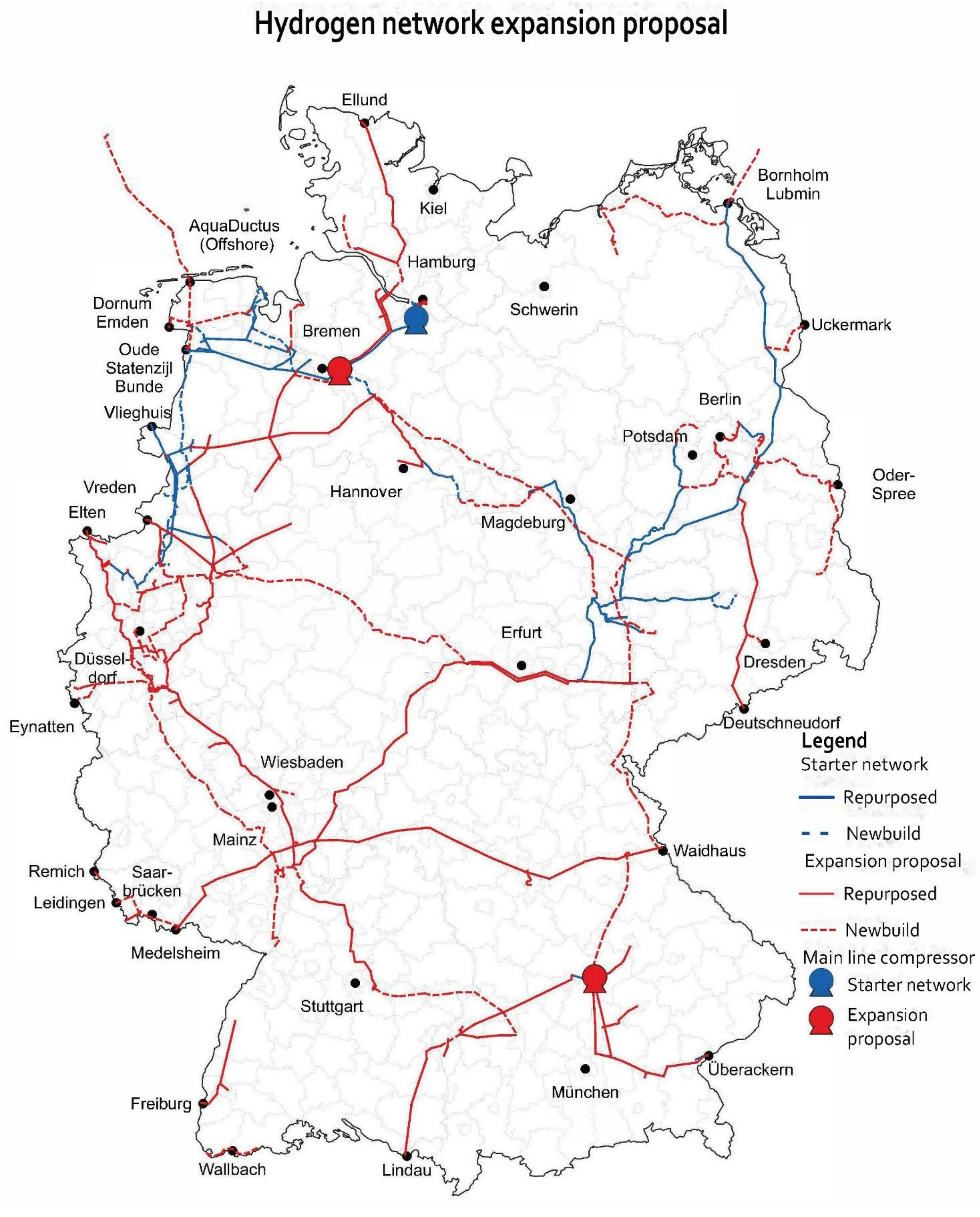
* rounded values

** 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 7,007 km with an investment volume of around €20.1 billion. Adding the hydrogen initial network measures with a pipeline length of 2,199 km (investment volume around €4.1 billion) gives a total hydrogen infrastructure length of around 9,206 km (investment volume around €24.2 billion).

Figure 38: Hydrogen network expansion proposal



Source: Coordination Office for Gas and Hydrogen Network Development Planning

The operators of hydrogen transmission networks 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, H2–0085–01) will still be needed for methane transportation in 2030 due to the emerging slight decline in methane demandand 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 Hafen-Neuss 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 no customer requirements were identified 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 operators of hydrogen transmission networks 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 operators of hydrogen transmission networks involved (OGE/Thyssengas H2) are endeavouring to meet customer requests for earlier project delivery.

Adjustment of hydrogen infrastructure planning in north-west 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.

Concluding remarks and outlook 8

8 Concluding remarks and outlook

With this document, the KO.NEP is submitting the draft Gas and Hydrogen Network Development Plan 2025 prepared by the gas TSOs and operators of hydrogen transmission networks for consultation.

By adopting an integrated view of methane and hydrogen as energy sources and improving alignment with the electricity transmission system operators' Network Development Plan, the network operators are taking another step towards holistic infrastructure planning. In addition, unlike in the past, the modelling for this Gas and Hydrogen Network Development Plan 2025 is scenario-based for the target years 2037 and 2045, allowing a wide range of probable developments in the context of the German government's climate and energy policy goals to be reflected here.

The scope of the integrated approach for methane and hydrogen based on three modelling scenarios has led to a much greater need for analysis. The gas TSOs and operators of hydrogen transmission networks are therefore publishing their Gas and Hydrogen Network Development Plan 2025 as part of a two-stage process.

The first stage is the publication of the draft Gas and Hydrogen Network Development Plan 2025 and the subsequent consultation process which will take place from 3 March 2026 to 27 March 2026. During this period, all interested parties will have the opportunity to comment in writing on the proposed Gas and Hydrogen Network Development Plan 2025.

The gas TSOs and operators of hydrogen transmission networks invite all interested parties to participate in the consultation and welcome public involvement. A workshop has been scheduled for 11 March 2026 from 9:00 until 12:30 to present the key results of the draft Gas and Hydrogen Network Development Plan 2025.

The second stage of the process will see the draft Gas and Hydrogen Network Development Plan 2025 revised to incorporate the results of the consultation. This revised draft will include the modelling results for hydrogen in the reference year 2045 and the modelling of the MBIs. The revised draft of the Gas and Hydrogen Network Development Plan 2025 is expected to be submitted to the BNetzA for approval in mid-2026.

Annexes and appendices

Annexes

Annex 1a: Methane projects discontinued in the course of modelling the Gas and Hydrogen Network Development Plan 2025

No.	ID number	Expansion measure	Reason for the measure being omitted
1	301–01	Embsen transmission	Efficient development of the Achim/Embsen compressor site, including by means of natural gas-reinforcing measure (1030-01) as part of the core network modelling
2	624–01	Weißensberg 2 M&R station	Measure no longer required due to decline in methane demand
3	626–01	Aalen-Essingen pipeline	Measure no longer required due to decline in demand for methane
4	635–01	Embsen M&R station	Efficient development of the Achim/Embsen compressor site, including by means of natural gas-reinforcing measure (1030) as part of the core network modelling
5	637–02	Achim compressor upgrade	Efficient development of the Achim/Embsen compressor site, including natural gas-reinforcing measure (1030) as part of the core network modelling
6	639–01	M&R station Achim	Efficient development of the Achim/Embsen compressor site, including natural gas-reinforcing measure (1030) as part of the core network modelling
7	761–01	Egenstedt-Clauen pipeline	Measure longer required for capacity reasons
8	762–01	Wallach-Alpen pipeline	The Sonsbeck-Hamborn pipeline is not part of the hydrogen network. An alternative methane supply for Alpen therefore does not need to be established.
9	763–01	Budberg-Eversael pipeline	The Sonsbeck-Hamborn pipeline is not part of the hydrogen network. An alternative methane supply for Alpen therefore does not need to be provided.
10	764–01	Reconnection of connecting pipelines in Sonsbeck-Oberhausen	The Sonsbeck-Hamborn pipeline is not part of the hydrogen network. An alternative methane supply for the connected exit points therefore does not need to be provided.
11	765–01	Glehn II M&R station	The Sonsbeck-Hamborn pipeline is not part of the hydrogen network. Additional entries in the direction of the western Ruhr area via Glehn are therefore not required.
12	766–01	Hamborn I M&R station	The Sonsbeck-Hamborn pipeline is not part of the hydrogen network. The supply to Oberhausen can therefore continue unchanged.
13	812–01	Bergen-Burg pipeline	Reduction in planned transportation capacity
14	813–01	Spreetal pipeline – southern junction system	Change in planned network operation
15	814–01	Lauchhammer 2 compressor station	By changing the MAP assignment to MAP Lauchhammer
16	816–01	Spreetal M&R station	Change in planned supply to improve pressure for additional industrial demand
17	817–01	Spreetal valve station	Change to planned supply to improve pressure for additional industrial demand

18	828–01	Knapsack connection pipeline	As a power plant in Knapsack is no longer classified as systemically relevant, there is no longer any need to construct the connection pipeline.
19	836–01	Verlautenheide II M&R station expansion	Based on demand trends, even in conjunction with the market area conversion, there is no additional need for internal market area coupling beyond the existing plant capacities.
20	888–01	Vorweden M&R station	Postponement of planned GDRA redundancy to other network parameters
21	889–01	Groß Tessin LNG terminal pipeline – (NEL)	Measure cancelled without replacement due to LNG capacity reduction from 10 GWh/h to 1.5 GWh/h
22	929–01	Groß Tessin M&R station	Measure cancelled without replacement due to LNG capacity reduction from 10 GWh/h to 1.5 GWh/h.
23	930–01	Groß Tessin compressor station	Measure cancelled without replacement due to LNG capacity reduction from 10 GWh/h to 1.5 GWh/h.
24	946–01	Modification of Quarnstedt compressor station	Imports from Denmark will be transported in addition to LNG thanks to natural gas-reinforcing measures ID 767-03 and ID 1030-01. The pressure ratio via the Quarnstedt compressor is sufficient for this purpose. The natural gas-reinforcing measure to enable the serial use of the existing compressors in Quarnstedt is therefore no longer required.
25	948–01	Transfer on the Bobbau-Großkugel pipeline system at Queis	Relocation to another network point without installing new lines
26	949–01	Transfer on the Bobbau-Großkugel pipeline system near Gollma	Relocation to another network point without installing new lines
27	953–01	Friesack-Friesack II pipeline	Pipeline remains connected to methane network, no reconnection required
28	954–01	Friesack II-Möthlow pipeline	Pipeline remains connected to methane network, no reconnection required
29	955–01	Friesack-Dreetz pipeline	Pipeline remains connected to methane network, no reconnection required
30	956–01	Dreetz-Neustadt pipeline	Pipeline remains connected to methane network, no reconnection required
31	957–01	Neustadt-Kyritz pipeline	Pipeline remains connected to methane network, no reconnection required
32	958–01	Kyritz-Kyritz II pipeline	Pipeline remains connected to methane network, no reconnection required
33	959–01	Kyritz II-Vehlow pipeline	Pipeline remains connected to methane network, no reconnection required
34	962–01	Levitzow M&R station	No replacement measure required, as existing system is active again in the methane network
35	963–01	Levitzow connection pipeline	No replacement measure required, as existing system is active again in the methane network.
36	966–01	Expansion of Bernau M&R station	Measureno longer required for capacity reasons

37	967–01	Xanten M&R station	The use of the Epe/Xanten storage facility zone no longer requires regulation of the Xanten-Appeldorn and Xanten-Wallach flows in connection with the conversion of the Xanten-Wallach pipeline to hydrogen.
38	969–01	Levitzow valve station	Cancellation of measures ID 962-01 ("Levitzow M&R station") and ID 963-01 ("Levitzow connection line"), meaning that a valve station in Levitzow is no longer necessary.
39	1003–01	Schnaitsee-Bierwang and Burghausen-Schnaitsee pipeline connection	Not required due to relocation of MAP capacity.
40	1004–01	Schnaitsee-Bierwang and Gröben-Schachen pipeline connection	Measure replaced by measure ID 1155-01.
41	1005–01	Bierwang 6 M&R station	Measure replaced by measure ID 1155-01.
42	1008–01	Reconnection on the Anwaltig-Schnaitsee pipeline system	No methane supply required. Coordination with DSOs.
43	1034–01	Unterlüß Kolshorn pipeline	Measure no longer required for capacity reasons
44	1038–01	Reconnection on the Belm-Haaren pipeline system	Measure no longer required for capacity reasons
45	1047–01	Rimpar-Hüttendorf pipeline	Contrary to the assumption that all hydrogen core network conversion measures can be converted to hydrogen by the end of 2032, the MEGAL section from Gernsheim to Rothenstadt (H2–0084–01, H2–0085–01) will still be needed in 2030 for transportation in the methane network due to the lower-than-anticipated decline of methane sales and additional demand for power plants. Removal by 2032 would entail significant natural gas-reinforcing measures. The hydrogen calculations for 2037 in scenarios 1, 2 and 3 have shown that the hydrogen transportation demand only requires a conversion of the MEGAL between Gernsheim and Rothenstadt from methane to hydrogen in scenarios 1 and 2. The commissioning of the measure will therefore be postponed from 12/2032 to 12/2034, as approved by the hydrogen core network. The NDP 2027 will review the switch to 12/2034. As the natural gas-reinforcing measures at the Rimpar compressor station (1048–01), Rothenstadt compressor station (1049–01) and the MEGAL loop line (Rimpar-Hüttendorf) (1047–01) can be dispensed with in scenarios 1 and 2, they will be eliminated from NDP 2025.
46	1048–01	Rimpar compressor station	Contrary to the assumption that all hydrogen core network conversion measures can be converted to hydrogen by the end of 2032, the MEGAL section from Gernsheim to Rothenstadt (H2–0084–01, H2–0085–01) will still be needed in 2030 for transportation in the methane network due to the lower-than-anticipated decline of methane sales and additional demand for power plants. Removal by 2032 would entail significant natural gas-reinforcing measures. The hydrogen calculations for 2037 in scenarios 1, 2 and 3 have shown that the hydrogen transportation demand only requires a conversion of the MEGAL between Gernsheim and Rothenstadt from methane to hydrogen in scenarios 1 and 2. The commissioning of the measure

			will therefore be postponed from 12/2032 to 12/2034, as approved by the core network. The NDP 2027 will review the switch to 12/2034. As the natural gas-reinforcing measures at the Rimpar compressor station (1048–01), Rothenstadt compressor station (1049–01) and the MEGAL loop line (Rimpar-Hüttendorf) (1047–01) can be dispensed with in scenarios 1 and 2, they will be eliminated from NDP 2025.
47	1049–01	Rothenstadt compressor station	Contrary to the assumption that all core network conversion measures can be converted to hydrogen by the end of 2032, the MEGAL section from Gernsheim to Rothenstadt (H2–0084–01, H2–0085–01) will still be needed in 2030 for transportation in the methane network due to the lower-than-anticipated decline of methane sales and additional demand for power plants. Removal by 2032 would entail significant natural gas-reinforcing measures. The hydrogen calculations for 2037 in scenarios 1, 2 and 3 have shown that the hydrogen transport demand only requires a conversion of the MEGAL between Gernsheim and Rothenstadt from methane to hydrogen in scenarios 1 and 2. The commissioning of the measure will therefore be postponed from 12/2032 to 12/2034, as approved by the core network. The NDP 2027 will review the switch to 12/2034. As the natural gas-reinforcing measures at the Rimpar compressor station (1048–01), Rothenstadt compressor station (1049–01) and the MEGAL loop line (Rimpar-Hüttendorf) (1047–01) can be dispensed with in scenarios 1 and 2, they will be eliminated from NDP 2025.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Annex 2b: Hydrogen projects discontinued in the course of modelling the Gas and Hydrogen Network Development Plan 2025

No.	ID number	Expansion measure	Reason for the measure being omitted
1	KLN001–01	Überackern-Haiming pipeline incl. M&R stations	The Überackern-Haiming hydrogen core network newbuild project (KLN1001–01) will be replaced by the conversion measure (KLN1001–01) of the Gas and Hydrogen Network Development Plan 2025.
2	KLN022–01	Ellund-Niebüll pipeline incl. M&R station	In the market survey for hydrogen projects for NDP 2025, a hydrogen entry capacity of 75 MW was reported for the Niebüll area in 2030. However, this capacity was disproportionate to the planned construction of a new 30 km hydrogen pipeline to connect to Hyperlink 3. For this reason, the Ellund-Niebüll pipeline was not initially included in the NDP 2025 expansion proposal. However, the TSOs reserve the right to re-include the pipeline in the network expansion proposal if there is a significantly higher demand for capacity in future, which is currently the subject of intense debate.
3	KLN025–01	Wardenburg-Ganderkesee pipeline incl. M&R station	The KLN029–01 Wilhelmshaven-Wardenburg hydrogen core network measure (NDP ID H2–1029–01) was modified due to changed input parameters and, consequently, as a result of modelling. The reasons for this are both the changed location of the offshore pipeline connection and the KLN024–01 Barßel-Wardenburg and KLN031–01 Barßel-Emsbüren measures, which were eliminated from the hydrogen core network approval. The hydrogen core network measure KLN029–01 now plays a greater role in the distribution and transport of hydrogen from western to eastern Germany. For this reason, the endpoint of the measure will now be further east in Ganderkesee instead of in Wardenburg. Consequently, the core network measure KLN025–01 Wardenburg-Ganderkesee can be eliminated and has therefore not been included in the hydrogen core network operator's expansion proposal, which represents a cost-efficient further development of the core network.
4	KLU045–01	Luttum-Lehringen pipeline incl. M&R stations	Following the adjustment of the pipeline length and the end point in the course of route planning for hydrogen core network measure KLN027–01 Achim-Luttum/Lehringen, the surrounding infrastructure will also change. This means in particular that the KLU045–01 Luttum-Lehringen measure will no longer be necessary, which represents an efficient next step in the development of the hydrogen core network. The pipline is no longer required to connect the points Achim and Lehringen.

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Annex 3: Overview of L-to-H-gas conversion areas until 2029

Areas	TSO	Conversion year
EWE Zone Part VII	GTG	2026
Bielefeld/Paderborn	GUD	2026
in production area/upstream	GUD	2026
Rehden-Lengerich area	Nowega	2026
Düsseldorf	OGE/Thyssengas	2026
Werne-Ummeln-Drohne	OGE	2026
Emmerich	TG	2026
EWE zone, part VIII	GTG	2027
Westnetz zone	GTG	2027
Salzgitter III	Nowega	2027
Werne-Ummeln-Drohne	OGE	2027
Sonsbeck-Dorsten	OGE	2027
Rommerskirchen/Kerpen	OGE	2027
Hürth/Brühl/Bergheim 2	TG	2027
Rommerskirchen/Blatzheim	TG	2027
Sonsbeck-Oberhausen	TG	2027
Weisweiler/Düren	TG	2027
Chapels	TG	2027
Emsland II	Nowega	2028
Salzgitter I	Nowega	2028
Krefeld-Langenfeld	OGE/Thyssengas	2028
Dorsten-Leichlingen	OGE/Thyssengas	2028
Sonsbeck-Dorsten	OGE	2028
Kalkar/Uedem/Aldekerk	TG	2028
Voigtei (CCGT)	GUD	2029
Petershagen Messlinger Street	Nowega	2029
Salzgitter II	Nowega	2029
Münsterland	OGE	2029
Gescher	OGE	2029
Haanrade	TG	2029

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Annex 4: Potential hydrogen M&R stations

No	Measure	Scenario 1 2037	Scenario 2 2037	Scenario 3 2037
1	AquaDuctus M&R station	x	x	x
2	Finsing 1 M&R station	x	x	x
3	Lengthal 1 M&R station	x	x	x
4	Münchsmünster M&R station	x	x	–
5	Wertingen M&R station	–	x	x
6	Finsing 2 M&R station	x	x	x
7	Irsching/Menning M&R station	x	x	x
8	Lengthal 2 M&R station	x	x	x
9	Schnaitsee 1 M&R station	x	x	x
10	Forchheim M&R station	x	x	x
11	Ronneburg M&R station	x	x	x
12	Jena M&R station	x	x	x
13	Bad Lauchstädt M&R station	x	x	x
14	Bobbau 2 M&R station	x	x	–
15	Lampertheim 3 M&R station	x	x	x
16	Greifenhagen (PL) M&R station	x	x	x
17	Lubmin M&R station	x	x	x
18	Deutschneudorf M&R station	x	x	x
19	Sande M&R station	x	x	x
20	Sandkrug M&R station	x	x	x
21	Leer/Nüttermoor M&R station	x	x	x
22	Westerstede M&R station	x	x	x
23	IP Bunde/Oude M&R station	x	x	x
24	Sande/Dyckhausen M&R station	x	x	–
25	Ellund M&R station	x	x	x
26	Klein Offenseth M&R station	x	x	x
27	Lemförde/Drohne M&R station	x	x	–
28	Lehringen M&R station	x	x	x
29	Kolshorn M&R station	x	x	x
30	Wardenburg/Ganderkesee M&R station	x	x	–
31	Heist M&R station	x	x	x
32	Achim M&R station	x	x	x
33	Brunsbüttel M&R station	x	x	x
34	Salzgitter/Hallendorf M&R station	x	x	x
35	Waidhaus 1 M&R station	x	x	x
36	Waidhaus 2 M&R station	x	x	x

37	Herrnsheim M&R station	x	x	–
38	Erlangen M&R station	x	x	–
39	Herchenrode M&R station	x	x	–
40	Medelsheim M&R station	x	x	x
41	Haskamp M&R station	x	x	x
42	Schepsdorf/Lohne M&R station	x	x	x
43	Emsbüren 1 M&R station	x	x	x
44	Bunde 1 M&R station	x	x	x
45	Fret 2 M&R station	x	x	x
46	Dorsten 1 M&R station	x	x	x
47	Dorsten 2 M&R station	x	x	–
48	Paffrath M&R station	x	x	x
49	Lichtenbusch M&R station	x	x	x
50	Gernsheim M&R station	x	x	x
51	Albachten M&R station	x	x	x
52	Emden 1 M&R station	x	x	–
53	Werne 1 M&R station	x	x	–
54	Stevede 2 M&R station	x	x	x
55	Ahlten M&R station	x	x	x
56	Krefeld/St. Hubert M&R station	x	x	–
57	Lampertheim 1 M&R station	x	x	x
58	Oberaden/Lünen M&R station	x	x	–
59	Wesseling M&R station	x	x	x
60	Karlsruhe-Rheinhafen M&R station	x	x	–
61	Steinfurt M&R station	x	–	–
62	Vreden M&R station	x	x	–
63	Scheidt M&R station	–	x	–
64	Elgendorf M&R station	x	–	–
65	Mittelbrunn M&R station	x	x	–
66	Weisweiler 1 M&R station	x	x	x
67	Wiefelstede M&R station	x	x	–
68	Emden 2 M&R station	x	x	–
69	Leverkusen M&R station	x	x	x
70	Ludwigshafen/Frankenthal 1 M&R station	x	x	–
71	Ludwigshafen/Frankenthal 2 M&R station	x	x	–
72	Schnaitsee 2 M&R station	x	x	–
73	Wardenburg 1 M&R station	x	x	–
74	Kitzen M&R station	x	x	–
75	Rostock M&R station	x	x	x

76	Wefensleben M&R station	x	x	x
77	Hennickendorf M&R station	x	x	x
78	Kleinziethen M&R station	x	x	–
79	Buchholz M&R station	x	x	x
80	Bobbau 1 M&R station	x	x	x
81	Sticks M&R station	x	x	x
82	Uhrsleben M&R station	x	x	–
83	Eisenach M&R station	x	x	x
84	Walstedde M&R station	x	x	x
85	Emlichheim M&R station	x	x	x
86	Emsbüren 2 M&R station	x	x	x
87	Uedemer Bruch M&R station	x	x	x
88	Amelsbüren M&R station	x	x	x
89	Werne 2 M&R station	x	x	x
90	Elten M&R station	x	x	x
91	Recklinghausen M&R station	x	x	–
92	Lampertheim 2 M&R station	–	–	x
93	Bad Bentheim M&R station	x	x	x
94	Freiburg M&R station	x	x	x
95	Haiming M&R station	x	x	x
96	Aichschieß M&R station	x	x	-
97	Leidingen M&R station	x	x	x
98	Seyweiler M&R station	x	x	x
99	Fürstenhausen M&R station	x	x	x
100	Coswig M&R station	x	-	-
101	Blumberg M&R station	x	x	-
102	Osdorfer Street M&R station	x	x	-
103	Außig M&R station	x	x	x

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Annex 5: Pipeline sections of the 2045 methane network

Name (from - to)	Length in km	Nominal diameter (DN) in mm	Pressure (DP) in bar	Owner
Burghausen (Haiming)-Finsing	87	1,200	100.0	bayernets
Finsing-Anwalting	82	900	80.0	bayernets/OGE
Wertingen-Kötz	41	700	100.0	Bayernets
Kötz-KW Leipheim junction	2	450	60	bayernets/terranets bw
Rehden-Lubmin	441	1,400	100.0	GASCADE/GUD/Fluxys D
Lubmin-Brandov	480	1,400	100.0	GASCADE/GUD/Fluxys D/ONTRAS
Rehden-Drohne	26	1,000	100.0	GASCADE
Emsbüren-Hünxe	96	1,000	42	Thyssengas
Epe-Heek	8	600	67.5	Thyssengas
Hünxe-Hamborn	32	600/700	67.5	Thyssengas
Hamborn-Lintorf	20	600	67.5	Thyssengas
Lintorf-Glehn	33	500	70	Thyssengas
Bocholtz-Glehn	78	300/400/500	67.5	Thyssengas
Elten-Paffrath	154	800–1,000	67.5	Thyssengas/OGE
Epe-Ochtrup	12	600	70	Thyssengas
Gelding-Binsheim	18	600	67.5	Thyssengas
Binsheim-Hamborn	6	600	67.5	Thyssengas/OGE
Wallach-Appeldorn	20	400	67.5	Thyssengas
Ochtrup Dates	71	600	70	Thyssengas
Datteln-Herne	23	600	70	Thyssengas
Hoeningen-Bergheim	23	400 and 400/600	70	Thyssengas
Lauchhammer-Lasow (Poland)	114	500/600/800	55	ONTRAS
Lauchhammer-Cörmigk	143	600/750/800/900	55.0	ONTRAS
Cörmigk-UGS Bernburg	9	750	55.0	ONTRAS
Cörmigk-Milzau	40	750	55.0	ONTRAS
Milzau-Böhlen/Lippendorf	55	500/600/800/900	55	ONTRAS
Milzau-UGS Bad Lauchstädt	8	600	55.0	ONTRAS
Sülstorf-Rostock	113	400/500	55.0	ONTRAS
Überackern-Haiming	1	700	84.0	bayernets/OGE

Name (from - to)	Length in km	Nominal diameter (DN) in mm	Pressure (DP) in bar	Owner
Dornum-Wardenburg	106	1,200	84.0	GUD/OGE
Wardenburg-Werne	197	900–1,200	67.5/84	OGE
Werne-Dorsten	88	800–1,000	67.5	OGE
Eynatten-Würselen	13	900	84.0	Fluxys/OGE/Thyssengas
Würselen-Porz	83	800	100	OGE
Werne-Paffrath	106	800–1,000	67.5	OGE
Werne-Stockum	10	600	67.5	OGE
Hennen-Eisborn	23	600	67.5	OGE
Eisborn-Hamm	41	500	67.5	OGE
Paffrath-Gernsheim	205	800–1,200	67.5	OGE
Waidhaus-Medelsheim	458	900–1,200	80/84	NaTran_D/OGE
Rothenstadt-Finsing	180	100	100	OGE
Schwandorf-Oberkappel	167	800	67.5	NaTran_D/OGE
Brensbach-Staudinger power station	42	500	80	OGE
Mittebrunn-Wallbach	273	900/1,000	67.5	Fluxys/OGE
Bocholtz-Stolberg	14	950	67.5	Fluxys/OGE
Ellund-Fokbeck	64	500	84.0	GUD/OGE
Klein-Offenseth-Elbe South	30	750	70	GUD/OGE
Reichertsheim-Bierwang	11	800	80	OGE
Herchenrode-Lampertheim	34	1,000	90.0	terranets bw
Lampertheim-Grenzhof	25	700	67.5	terranets bw
Grenzhof-Blankenloch	47	600	67.5	terranets bw
Kirrlach-Heilbronn	48	400	50	terranets bw
Heilbronn-Metterzimmern	20	300	50	terranets bw
Metterzimmern-Wiernsheim	25	500	80	terranets bw
Blankenloch-Dürrlewang	70	600	56	terranets bw
Dürrlewang-Scharenstetten	70	500	56.0	terranets bw
Scharenstetten-Essingen	41	500	67.5	terranets bw
Essingen-Aalen	9	200	67.5	terranets bw
Scharenstetten-Weißensberg	136	500	67.5	terranets bw

Name (from - to)	Length in km	Nominal diameter (DN) in mm	Pressure (DP) in bar	Owner
Weißensberg-Lindau	3	500	67.5	terranets bw/bayernets
Tunsel-Basel	39	300	54.0	terranets bw
Oude-Folmhusen	24	600	70.0	GUD/Thyssengas
Emden-Folmhusen	65	750/1,000	84/70	GUD/Thyssengas
Bunde-Emsbüren	98	750	68	GUD/Thyssengas
Lingen-Uelsen	27	600	84	GUD
Folmhusen-Ganderkesee	57	750	70	GUD
Ganderkesee-Achim	41	900	70	GUD
Achim-Heidenau	53	450	70	GUD
Heidenau-Elbe South	41	600	80.0	GUD
Klein Offenseth-Quarnstedt	16	500	70	GUD
Quarnstedt-Fockbek	47	400	70	GUD
Achim-Kolshorn	112	600	70	GUD
Kolshorn-Mehrum	15	500	70	GUD

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Annex 6: Overview of pipelines reported for the 2045 hydrogen modelling

No	Pipeline	Conversion/ New pipeline	Nominal diameter [DN]	Length [km]	Pressure [DP]
1	Schöninghsdorf-Emmeln	conversion	600	17.5	67.5
2	Alsdorf-Alsdorf	new pipeline	250	1.0	70
3	Emden-Etzel	conversion	1,100	67.0	80/84
4	Wilhelmshaven-Etzel	conversion	1,000	26	100
5	Emden-Werne	conversion	1,000/1,100	240	70
6	Drone-Steinbrink	conversion	600	28.2	70
7	Steinbrink-Vinnhorst	conversion	700	81.8	70
8	Vinnhorst-Ahlten	conversion	600	21.3	84
9	Connection cable Epe	conversion	700	4.5	80
10	Epe-Wettringen	conversion	800	25.8	84
11	Epe-Legden	conversion	1,100	14.6	100
12	Mittelbrunn-Remich	conversion	500	113.6	84
13	Gernsheim-Gernsheim	conversion	500/600	4.1	67
14	Gernsheim-Lampertheim	conversion	600	19.4	67
15	Lampertheim-Karlsruhe	conversion	500	78.4	61
16	Radevormwald-Niederschelden	conversion	500	65.5	67.5
17	Obermichelbach-Amerdingen	conversion	900	104.7	80
18	Reinhardshofen-Michelbach	conversion	500	62.9	80
19	Arresting-Bierwang	conversion	800	103.5	84
20	Gernsheim-Rimpar	conversion	500/700	107.4	67.5
21	Rimpar-Waidhaus	conversion	700/900	211.8	67.5
22	Werne-Sannerz	conversion	1,200	257.4	100
23	Sannerz-Rimpar	conversion	1,000	67.6	100
24	Schlüchtern-Rimpar	conversion	700	68.5	84
25	Werne-Duisburg	conversion	700/800	94.8	70
26	Sonsbeck-Hamborn	conversion	500	30.1	50
27	Eynatten-Legden	conversion	1,000	216.1	100
28	St. Hubert-Lintorf	conversion	700	32.8	67.5
29	Bocholtz-Mittelbrunn	conversion	1,000	223.6	67.5
30	Au am Rhein-Wallbach	new pipeline	900/1,000	193.8	70
31	Wardenburg-Achim	conversion	1,200	66.2	84
32	Achim-Steinitz	conversion	1,200	169.4	84
33	Steinitz-Bernau	conversion	1,100	181.4	84
34	Bernau-Blumberg	conversion	600/1,100	19.3	84

No	Pipeline	Conversion/ New pipeline	Nominal diameter [DN]	Length [km]	Pressure [DP]
35	Börnicke-Kienbaum	conversion	1,100	40.6	100
36	Amerdingen-Wertingen	conversion	800	29.1	80
37	Bierwang-Breitbrunn	conversion	700/800	27.3	80
38	Hamborn-Lintorf	conversion	600	20.1	70
39	Allsum-Allsum	conversion	500	1.6	67.5
40	Allsum-Hamborn	conversion	600	4.6	70
41	Lintorf-Uellendahl	conversion	500	28	40
42	Dorsten-Werne	conversion	400	56.8	50
43	Mengede-Dortmund-Scharnhorst	conversion	400	12.3	50
44	Castrop-Rauxel-Witten	conversion	400	18.2	50
45	Stiepel-Bochum-Westpark	conversion	400	7.8	70
46	Zons-Selikum	conversion	400	14.3	40
47	Friemersheim-DU-Port	conversion	30	8.9	67.5
48	Dorsten-Lintorf	conversion	400	41.8	50
49	Ahrem-Euskirchen	conversion	400	18.5	100
50	Euskirchen-Brüser Berg	conversion	300	27.2	70
51	Bonn-Rheinaue-Godesberg	conversion	400	4.0	70
52	Godesberg-Brüser Berg	conversion	30	12.4	67.5
53	Duisburg-Baerl-Alt-Homberg	conversion	300/500	6.4	70
54	Niederbonsfeld-Essen-South	conversion	500	10.1	70
55	Breitbrunn-Bierwang	conversion	400/500	8.1	70
56	Diesenbach-Regensburg	conversion	300	10.8	70
57	Hinterschwarzenberg-Pfronten	conversion	150/200	21.5	80
58	Mintsberg-Wernhardberg	conversion	600	2.0	70
59	Katzdorf-Diesenbach	conversion	300	10.2	70
60	Connecting pipeline in Finsing	conversion	400/700	0.1	67.5
61	Finsing-Wolfersberg	conversion	700	20.6	67.5
62	Münchsmünster-Ingolstadt	conversion	400	23	67.5
63	Finsing-Bierwang	conversion	500	47.3	70
64	Ingolstadt-Augsburg	conversion	400	69.1	67.5
65	Anwalting-Kissing	conversion	500	20.7	70

No	Pipeline	Conversion/ New pipeline	Nominal diameter [DN]	Length [km]	Pressure [DP]
66	Gröben-Bierwang	conversion	500	2.5	80
67	Egmating-Kissing	conversion	500	82.6	70
68	Inzenham-Kiefersfelden	conversion	400	39.4	70
69	Inzenham-Egmating	conversion	600	32	70
70	Egmating-Kempten	conversion	400/500	145.8	80
71	Kötz-Hittistetten/Senden	conversion	450/500	13.7	60
72	Burghausen-Schnaitsee	conversion	800	4.1	84
73	Gröbn-Gröbn	conversion	500	0	84
74	Regensburg-Oberisling	conversion	300	15.0	70
75	Finsing-Finsing	conversion	500/600	0	70
76	Egmating-Oberpframmern	conversion	600	0.2	70
77	Büttgen-Erkelenz	conversion	450	24.1	67.5
78	Rehden distribution station-Hallendorf station	conversion	600	160.3	64/70
79	Steinbrink distribution station Voigtei	conversion	600	18.3	70
80	Ueldener Haar-Plackweg	conversion	400	17.2	70
81	Ochtrup-Ochtrup1	conversion	400	0.1	70
82	Gronau-Gronau	conversion	400	0.1	70
83	Lemmie II station-Empelde GHG station (storage)	conversion	400	6.9	70
84	Leer-Holte	conversion	1,000	12.8	84
85	Mixing station Gr. Gießen-Bolzum station	conversion	250	13.4	64
86	Mixing station Gr. Gießen-distribution station Kolshorn	conversion	350/450	26.7	70
87	Neuss-Neukirchen	conversion	400	11.6	67.5
88	Borken-Bocholt	conversion	400	15.5	70
89	Egenstedt mixing station-Lenglern station	conversion	45	63.5	64
90	Egenstedt mixing station-Ahlten station	conversion	600	35.0	84
91	Voerde-Hünxe	conversion	700	6.1	70
92	HerneC-Bochum	conversion	400	8.6	70
93	Kolshorn distribution station-Clenze station	conversion	450/600	53.1	70
94	Ueldener Haar-Ueldener Haar	conversion	400	0.3	70

No	Pipeline	Conversion/ New pipeline	Nominal diameter [DN]	Length [km]	Pressure [DP]
95	Xanten-Appeldorn	conversion	400	22.1	67.5
96	Bockum-Olfen	conversion	600	4.7	70
97	Ueldener Haar-Ueldener Haar	conversion	400	0	70
98	Herne-Recklinghausen	conversion	400	8.0	70
99	Oberaußem-Horrem	conversion	400	7.2	67.5
100	HerneB-Datteln	conversion	600	22.6	70
101	Büttgen-Büttgen	conversion	400	0.1	70
102	Lintorf-Hamborn	conversion	600	17.7	70
103	Dülmen-Coesfeld	conversion	600	12.3	70
104	Gronau-Epe	conversion	600	2.7	70
105	Lintorf-Büttgen	conversion	500	0	70
106	Gronau1-Ochtrup2	conversion	600	3.0	84
107	Mölln-Hamborn	conversion	600	14.5	70
108	Erkelenz-Broichweiden	conversion	400	35.8	67.5
109	Hiltrop-Laer	conversion	400	4.4	70
110	Niedereimer-Haarweg	conversion	500	26.6	70
111	Gronau2-Ochtrup3	conversion	400	0.1	70
112	Recklinghausen-Oer Erkenschwick	conversion	400	6.5	70
113	Laer-Querenburg	conversion	400	2.2	70
114	Vetschau-Haren	conversion	500	8.8	100
115	Telgte-Stockum	conversion	600	34.1	70
116	Stockum-Holzwickede	conversion	600	24.5	70
117	Fröndenberg-Holzwickede	conversion	400	2.0	70
118	Ennigerloh-Oelde	conversion	400	16.3	70
119	Ochtrup Wester 18A-Ochtrup Hermann-LönsA	conversion	500	1.6	70
120	Gelding-Binsheim	conversion	600	17.3	70
121	Hürth-Kalscheuren	conversion	400	2.8	70
122	Aachen-Broichweiden	conversion	500	2.7	70
123	Ochtrup Wester 18B-Ochtrup Hermann-LönsB	conversion	500	1.6	70
124	Holzwickede-Bochum	conversion	400	30	70
125	Emden-Leer	conversion	750	43.8	84
126	Coesfeld-Gronau	conversion	600	31.9	70
127	Broichweiden-Münsterbusch	conversion	400	6.5	70

No	Pipeline	Conversion/ New pipeline	Nominal diameter [DN]	Length [km]	Pressure [DP]
128	Oer Erkenschwick-Recklinghausen	conversion	400	6.5	70
129	HerneA-HerneD	conversion	600	0.5	70
130	Olfen-Dülmen	conversion	600	18.2	70
131	Ochtrup Wester 10-Ennigerloh	conversion	600	80.2	70
132	Oelde-Uelde	conversion	400	37.1	70
133	Bunde-Emsbüren	conversion	600	22.1	70
134	Verlautenheide-Broichweiden	conversion	400	2.9	70
135	Bunde-Emsbüren	conversion	750	97.8	67.5
136	Ueldener Haar wines	conversion	500	14	70
137	Rapen-Bockum	conversion	600	3.9	70
138	Uelde-Wickede	conversion	400	31.8	70
139	Oer Erkenschwick-Rapen	conversion	400	1.5	70
140	Haren-Zwartemeer	conversion	600	17.3	67
141	Herne-Herne Hochlarmark	conversion	400	3.7	70
142	Ronneburg-Vitzeroda	conversion	800/1,000	187.4	84
143	Freienohl-Plackweg	conversion	200	7.1	70
144	Beckum-Gut Melschede	conversion	150	0.7	70
145	Hövel 1-Gut Melschede	conversion	30	0.2	40
146	Hövel-Hövel 1	conversion	250	0	40
147	Hövel-Olpe	conversion	250	3.8	40
148	Olpe-Olpe 1	conversion	300	0.1	40
150	Olpe 1-Freienohl	conversion	250	1.1	40
151	Waldenburg-Crailsheim	conversion	400	35.5	67.5
152	Michelbach-Essingen	conversion	500	54.9	67.5
153	Essingen-Scharenstetten	conversion	500	41.3	67.5
154	Wiernsheim-Löchgau	conversion	500	28.4	80
155	Wirtheim-Lampertheim	conversion	1,000	117	100
156	Wirtheim-Dörnigheim	conversion	500	39.5	64
157	Dörnigheim-Walldorf	conversion	500	30.1	64
158	Walldorf-Bischofsheim	conversion	500	13.3	64
159	Bischofsheim-Frankenthal	conversion	500	57.7	64
160	Lampertheim-Blankenloch	conversion	700	71.3	67.5
161	Blankenloch-Steinhäule	conversion	500	157.7	58

No	Pipeline	Conversion/ New pipeline	Nominal diameter [DN]	Length [km]	Pressure [DP]
162	Scharenstetten-Lindau	conversion	500	139.4	67.5
163	Amerdingen-Scharenstetten	conversion	700	57.4	80
164	Folmhusen-Wardenburg	conversion	1,000	47.6	84
165	Visbek-Lemförde	conversion	600	48.0	70
166	Achim-South Elbe	conversion	1,400	85	84
167	Helmste-Stade	conversion	900	18.0	84
168	Kolshorn-Peine	conversion	1,200	29.2	84
169	Peine-Walle	conversion	1,200	12.0	84
170	Walle-Edesbüttel	conversion	400	16.0	70
171	Bad Lauchstädt-Flößberg	conversion	800	75	100
172	Biemenhorst 1-Bocholt	conversion	300	1.6	70
173	Biemenhorst-Biemenhorst 1	conversion	250	0.2	67.5
174	Bocholt-Biemenhorst	conversion	200	3.2	67.5
175	Buckow-Lauchhammer	conversion	600	120.3	67.5
176	Flößberg-Merzdorf	conversion	900	46.9	63
177	Lauchhammer-Deutschneudorf	conversion	600	115.8	67.5
178	Merzdorf-Sayda	conversion	900	41.1	63
179	Niederhohndorf-Merzdorf	conversion	800	53.6	84
180	Oude-Bunde	conversion	400	2.4	84
181	Bunde-Leer	conversion	400	19.0	84
182	Leer-Nüttermoor	conversion	600	4.8	84
183	Huntorf-Ganderkesee	conversion	400	25	84
184	Ganderkesee-Cloppenburg	conversion	400	29.0	84
185	Cloppenburg-Leer	conversion	400	97.8	84
186	Cloppenburg-Steinfeld	conversion	400	26.9	84
187	Leer-Rastede	conversion	400	33.8	84

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Annex 7: Methane network expansion proposal

No.	NDP ID	Measure	Executing company
1	436–02b	Heiden-Dorsten pipeline	OGE
2	438–01	Valve stations Epe	OGE
3	450–01	Pfuhl M&R station (Steinhäule)	terranets bw
4	609–01	Wirtheim-Lampertheim pipeline	terranets bw
5	610–01	Wirtheim M&R station	terranets bw
6	611–01	Lampertheim M&R station	terranets bw
7	616–01	Heidelberg M&R station	terranets bw
8	618–01	Heilbronn M&R station	terranets bw
9	630–01	Lampertheim 5 M&R station	GASCADE
10	642–01	Ludwigshafen M&R station	GASCADE
11	653–01	Kleinenhammer M&R station and connecting pipeline	OGE
12	655–01	Essen Dellwig valve station and connecting pipeline	OGE
13	656–01	Duisburg Mündelheim valve station and connecting pipeline	OGE
14	658–01	Conversion to H-gas (Emsland II area)	Nowega
15	760–01	Transfer to the Rehden-Diepholz pipeline system	Nowega
16	768–01	Reconnection on the Hassel-Westen pipeline system	GUD
17	806–01	Lehringen M&R station	GUD
18	807–01	Kolshorn M&R station	GUD
19	808–01	Hämelerwald-Mehrum pipeline	GUD
20	810–01	Pipeline AS EUGAL-Lauchhammer 2	ONTRAS
21	811–01	Pipeline Lauchhammer 2-Großkoschen	ONTRAS
22	831–01	Lehringen M&R station	Nowega
23	832–01	Voigtei M&R station	Nowega
24	833–01	Rehden M&R station	Nowega
25	834–01	Beckedorf M&R station	Nowega
26	835–01	Staffhorst M&R station	Nowega
27	837–01	Hüls M&R station and connecting pipeline	OGE
28	838–01	Hamborn M&R station and connecting pipeline	OGE
29	840–01	Mündelheim M&R station and connecting pipeline	OGE
30	887–01	Connecting pipeline from Rostock to Marienehe	ONTRAS
31	903–01	Expansion of Friedeburg M&R station-Horsten 1 and connecting pipeline	OGE
32	931–01	Neuendorf M&R station	ONTRAS
33	941–01	Forchheim-Münchsmünster pipeline	bayernets
34	942–02	Neustadt a. d. Donau M&R station	bayernets
35	944–01	Münchsmünster pipeline connection	bayernets

36	950–01	Reconnection on the Schkeuditz-Lüptitz pipeline system at Gordemitz	ONTRAS
37	951–01	Reconnection on the Bobbau-Großkugel pipeline system near Bitterfeld-Wolfen	ONTRAS
38	952–01	Reconnection on the Bobbau-Großkugel pipeline system near Sandersdorf	ONTRAS
39	960–01	Reconnection on the Wedringen-Glöthe pipeline system	ONTRAS
40	961–01	Reconnection on the Wefensleben-Wedringen pipeline system	ONTRAS
41	965–01	Lauchhammer III pipeline-NK LH I	ONTRAS
42	968–01	Reconnection on the Xanten-Möllen pipeline system	Thyssengas
43	1001–01	Ingolstadt-Kösching pipeline connection	bayernets
44	1002–01	Schnaitsee-Bierwang and Bierwang-Gröben pipeline connection	bayernets
45	1006–01	Finsing 2M&R station	bayernets
46	1007–01	Reconnection on the Forchheim-Münchsmünster pipeline system	bayernets
47	1009–01	Reconnection on the Vohburg-Senden pipeline system	bayernets
48	1010–01	Reconnection on the Forchheim-Finsing pipeline system	bayernets
49	1015–01	Reconnection of a customer tie-in on STEGAL West to the Herbstein-Vitzeroda long-distance gas pipeline (OGE) near Wölfershausen	GASCADE
50	1016–01	EUGAL-OPAL pipeline connection	GASCADE
51	1018–01	Reconnection of a customer tie-in on MIDAL South to SPO (tnbw) near Bensheim	GASCADE
52	1019–01	Reconnection of a customer tie-in on MIDAL South to SPO (tnbw) near Dieburg	GASCADE
53	1020–01	Reconnection of a customer tie-in on MIDAL South to SPO (tnbw) near Gadernheim	GASCADE
54	1021–01	Reconnection of a customer tie-in on MIDAL South to SPO (tnbw) near Groß-Auheim	GASCADE
55	1022–01	Reconnection of a customer tie-in on MIDAL South to SPO (tnbw) near Herchenrode	GASCADE
56	1023–01	Reconnection of a customer tie-in on MIDAL South to SPO (tnbw) near Jügesheim	GASCADE
57	1024–01	Reconnection of a customer tie-in on MIDAL South to SPO (tnbw) near Klein-Auheim	GASCADE
58	1025–01	Reconnection of a customer tie-in on MIDAL South to SPO (tnbw) near Weinheim	GASCADE
59	1026–01	Reconnection of a customer tie-in on MIDAL South to SPO (tnbw) near Wirtheim	GASCADE
60	1027–01	Reconnection on the Rastede-Huntorf pipeline system	GTG
61	1028–01	Fockbek-Klein Offenseth pipeline	GUD
62	1029–01	Harsefeld-Brest/Doosthof pipeline	GUD

63	1030–01	Kolshorn-Peine pipeline	GUD
64	1032–01	Reconnection on the Achim-Heidenau pipeline system	GUD
65	1033–01	Lehringen production branch line	Nowega
66	1035–01	Altenlingen-Gersten pipeline	Nowega
67	1036–01	Voigtei-Lehringen pipeline	Nowega
68	1040–01b	System separations on the Wettringen-Werne pipeline system	OGE
69	1040–01c	System separations on the Werne-Paffrath pipeline system	OGE
70	1040–01d	System separations on the Paffrath-Lampertheim pipeline system	OGE
71	1040–01e	System disconnections on the Medelsheim-Gernsheim pipeline system	OGE
72	1040–01f	System disconnections on the Rothenstadt-Waidhaus pipeline system	OGE
73	1040–01i	System separations on the Elten-Paffrath pipeline system	OGE
74	1040–01j	System disconnections on other OGE pipeline systems	——
75	1041–01	Reconnection on the H2ercules Albachten-Ascheberg pipeline system	OGE
76	1042–01	Reconnection on the H2ercules Gescher-Dorsten pipeline system	——
77	1043–01	Reconnection on the H2ercules Gescher-Werne pipeline system	——
78	1044–01	Reconnection on the H2ercules Birlinghoven-Rüsselsheim pipeline system	OGE
79	1045–01	Reconnection on the H2ercules Werne-Paffrath pipeline system	OGE
80	1046–01	Reconnection on the H2ercules Werne-Ummeln pipeline system	——
81	1050–01	Reconnection on the Schkeuditz-Lüptitz pipeline system near Wiederitzsch	ONTRAS
82	1052–01	Reconnection on the Hittistetten-Lindau pipeline system	——
83	1053–01	Reconnection on the Bad Krozingen-Freiburg pipeline system	——
84	1055–01	Reconnection on the Hoeningen-Oberaußem pipeline system	Thyssengas
85	1056–01	Reconnection on the STEGAL pipeline system	GASCADE
86	1057–01	Bypasses on the Stade-Stade branch pipeline system	GUD
87	1058–01	Reconnection on the Borna-Thierbach pipeline system	ONTRAS
88	1059–01	Reconnection on the Milzau-Leuna pipeline system	ONTRAS
89	1060–01	Reconnection on the Leuna-Böhlen pipeline system	ONTRAS
90	1061–01	Reconnection on the Buchholz-Apollensdorf pipeline system	ONTRAS
91	1062–01	Reconnection on the Buchholz-Apollensdorf pipeline system	ONTRAS
92	1063–01	Reconnection on the Buchholz-Apollensdorf pipeline system	ONTRAS

93	1064–01	Reconnection on the Finsing-Ismaning Nord pipeline system (AND089–01)	bayernets
94	1065–01	Relocation of a biogas feed-in plant in Unterempfenbach on the Finsing-Ismaning North pipeline system (AND089–01)	bayernets
95	1066–01	Construction of a feed-back compressor for biogas feed-in plant in Unterempfenbach	bayernets
96	1067–01	Reconnection on the Finsing-Ismaning North pipeline system (AND089–01)	bayernets
97	1068–01	Reconnection on the Finsing-Ismaning North pipeline system (AND089–01)	bayernets
98	1069–01	Reconnection on the Finsing-Ismaning North pipeline system (AND089–01)	bayernets
99	1070–01	Ismaning M&R station	bayernets
100	1101–01	Woltorf-Walle pipeline	GUD
101	1103–01	Wilhelmshaven coastal pipeline (WKL)	OGE
102	1104–01	Hamborn Valve station	OGE
103	1105–01	Niederau gas pressure regulating station	ONTRAS
104	1106–01	Schraden valve station	ONTRAS
105	1107–01	Dülmen II M&R station	Thyssengas
106	1108–01	Expansion of Duisburg South M&R station	Thyssengas
107	1109–01	Hoeningen valve station	Thyssengas
108	1110–01	Expansion of Hoenningen M&R station	Thyssengas
109	1111–01	Friedrichsfeld-Möllen pipeline	Thyssengas
110	1112–01	Dülmen-Datteln pipeline	Thyssengas
111	1113–01	Kalscheuren-Fischenich pipeline	Thyssengas
112	1114–01	Rheinberg valve station	Thyssengas
113	1115–01	Herzogenrath valve station	Thyssengas
114	1116–01	Hoeningen-Oberaußem pipeline	Thyssengas
115	1151–01	Expansion of M&R station in Riedenburg	——
116	1152–01	Denkendorf M&R station	bayernets
117	1153–01	Expansion of M&R station in Katzdorf	——
118	1154–01	Riedenburg-Kelheim pipeline	——
119	1155–01	Burghausen-Finsing and Gröben-Gendorf pipeline connection	bayernets
120	1157–01	Bruckberg branch pipeline from 8201 to ENB ML12, including tapping into ENB ML12	——
121	1158	Conversion of Münchnerau junction	——
122	1159–01	Bypass line at Schnaitsee 1 M&R station	bayernets
123	1160–01	Rerouting of a customer connection (AL Gruben/Hünfeld) from MIDAL South to the MIDAL South loop at Hünhan.	GASCADE
124	1162–01	Transfers on the Brunsbüttel-Klein Offenseth pipeline system.	GUD

125	1163–01	Integration of DSO pipeline-Fockbek-Quarnstedt section	GUD
126	1164–01	Integration of DSO pipeline-Quarnstedt-Klein Offenseth section	GUD
127	1165–01	Reconnection on the Heidenau-Elbe South pipeline system	GUD
128	1166–01	Reconnection on the Kolshorn-Peine pipeline system	GUD
129	1168–01	Reconnection on the Dernbach Elgendorf-Bendorf pipeline system	——
130	1169–01	M&R station Bendorf and connecting pipeline	——
131	1170–01	System disconnections on the Dernbach Elgendorf-Bendorf South pipeline system	——
132	1171–01	System disconnections on the Neuss Harbour-Düsseldorf Harbour pipeline system	——
133	1172–01	System separations on the Birlinghoven-Beuel pipeline system	——
134	1173–01	New pipeline JAGAL-Bobbau pig trap	GASCADE

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Annex 8: Hydrogen network expansion proposal

No	Core network–ID	NDP–ID	Measure	Implementing company	Contact
1	KLU005–01	H2–0005–01	Finsing-Münchsmünster pipeline incl. M&R stations	bayernets	bayernets
2	KLU006–01	H2–0006–01	Schmidhausen-Moosburg pipeline incl. M&R stations	bayernets	bayernets
3	KLU007–01	H2–0007–01	Finsing-Schnaitsee pipeline incl. M&R stations	bayernets	bayernets, OGE
4	KLU008–01	H2–0008–01	Schnaitsee-Lengthal pipeline incl. M&R stations	bayernets	bayernets, OGE
5	KLU010–01	H2–0010–01	Kösching-Mailing pipeline incl. M&R stations	bayernets	bayernets
6	KLU011–01	H2–0011–01	Mailing-Kötz pipeline incl. M&R stations	bayernets	bayernets
7	KLU017–01	H2–0017–01	HYRER (Rückersdorf-Erfurt-Reckrod) incl. M&R stations	GASCADE	GASCADE
8	KLU018–01	H2–0018–01	HYRER (Rückersdorf-Erfurt-Reckrod) incl. M&R stations	GASCADE	GASCADE
9	KLU019–01	H2–0019–01	HYRER (Rückersdorf-Erfurt-Reckrod) incl. M&R stations	GASCADE	GASCADE
10	KLU020–01	H2–0020–01	HYRER (Rückersdorf-Erfurt-Reckrod) incl. M&R stations	GASCADE	GASCADE
11	KLU021–01	H2–0021–01	HYREL (Reckrod-Lampertheim) incl. M&R stations	GASCADE	GASCADE
12	KLU022–01	H2–0022–01	HYRER (Rückersdorf-Erfurt-Reckrod) incl. M&R stations	GASCADE	GASCADE
13	KLU023–01	H2–0023–01	HYOS (formerly OPAL) (Radeland-Zethau) incl. M&R stations	GASCADE/ LBTG	GASCADE
14	KLU024–01	H2–0024–01	HYOS (formerly EUGAL) (Zethau-Deutschneudorf) incl. M&R stations	GASCADE/ Fluxys D/ GUD/ ONTRAS	GASCADE
15	KLU034–01	H2–0034–01	Ganderkesee-Dötlingen pipeline incl. M&R station	GUD	GUD
16	KLU035–01	H2–0035–01	Dötlingen-Visbeck pipeline incl. M&R station	GUD	GUD
17	KLU036–01	H2–0036–01	Visbeck-Drohne pipeline incl. M&R station	GUD	GUD
18	KLU037–01	H2–0037–01	Achim-Heidenau pipeline incl. M&R station	GUD	GUD
19	KLU039–01	H2–0039–01	Heidenau-Elbe South pipeline incl. M&R station	GUD	GUD
20	KLU040–01	H2–0040–01	Elbe South-Elbe North pipeline incl. M&R station	GUD	GUD

21	KLU041–01	H2–0041–01	Elbe Nord-Heist pipeline incl. M&R station	GUD	GUD
22	KLU042–01	H2–0042–01	Fockbek-Ellund pipeline incl. M&R station	GUD	GUD
23	KLU047–01	H2–0047–01	Lemförde-Drohne pipeline incl. M&R station	GUD	GUD/ OGE
24	KLU048–01	H2–0048–01	Fockbek-Quarnstedt pipeline incl. M&R station	GUD	GUD
25	KLU049–01	H2–0049–01	Quarnstedt-Klein Offenseth pipeline incl. M&R station	GUD	GUD
26	KLU050–01	H2–0050–01	Heidenau-Elbe South pipeline incl. M&R station	---	GUD
27	KLU055–01	H2–0055–01	Rheden-Voigtei pipeline	Nowega	Nowega
28	KLU056–01	H2–0056–01	Voigtei-Weser pipeline	Nowega	Nowega
29	KLU057–01a	H2–0057–01a	Kohlshorn-Ahlten pipeline	Nowega	Nowega
30	KLU059–01	H2–0059–01	Reiningen-Georgsmarienhütte pipeline	Nowega	Nowega
31	KLU060–01a	H2–0060–01a	Schepsdorf-Schlootdamm/Steinfeld pipeline	Nowega	Nowega
32	KLU060–01b	H2–0060–01b	Schlootdamm/Steinfeld-Rehden pipeline	Nowega	Nowega
33	KLU061–01	H2–0061–01	Lehringen-Kohlshorn pipeline	Nowega/GUD	Nowega/GUD
34	KLU062–01	H2–0062–01	Weser-Lehringen pipeline	Nowega/GUD	Nowega/GUD
35	KLU063–01	H2–0063–01	Vinnhorst-Misburg pipeline, incl. M&R stations	---	OGE
36	KLU064–01	H2–0064–01	Misburg-Ahlten pipeline incl. M&R stations	---	OGE
37	KLU065–01	H2–0065–01	H2ercules Gersten-Emsbüren incl. M&R stations	---	OGE
38	KLU067–01	H2–0067–01	H2ercules Vreden-Gescher incl. M&R stations	---	OGE
39	KLU068–01	H2–0068–01	H2ercules Gescher-Werne incl. M&R stations	---	OGE
40	KLU069–01	H2–0069–01	H2ercules Gescher-Dorsten incl. M&R stations	---	OGE
41	KLU070–01	H2–0070–01	H2ercules Wettringen-Altbachten incl. M&R stations	OGE	OGE
42	KLU071–01	H2–0071–01	H2ercules Albachten-Ascheberg incl. M&R stations	OGE	OGE
43	KLU072–01	H2–0072–01	H2ercules Ascheberg-Werne incl. M&R stations	OGE	OGE
44	KLU073–01	H2–0073–01	H2ercules Werne-Ummeln incl. M&R stations	---	OGE

45	KLU074–01	H2–0074–01	H2ercules Werne-Paffrath incl. M&R stations	OGE	OGE
46	KLU075–01	H2–0075–01	H2ercules Paffrath-Niederkassel incl. M&R stations	OGE	OGE
47	KLU076–01	H2–0076–01	H2ercules Niederkassel-Birlinghoven incl. M&R stations	OGE	OGE
48	KLU077–01	H2–0077–01	H2ercules Birlinghoven-Rüsselsheim incl. M&R stations	OGE	OGE
49	KLU078–01	H2–0078–01	H2ercules Rüsselsheim-Lampertheim incl. M&R stations	OGE	OGE
50	KLU080–01	H2–0080–01	H2ercules Westhofen-Herdecke incl. M&R stations	OGE	OGE
51	KLU081–01	H2–0081–01	H2ercules Gernsheim North-Gernsheim South incl. M&R stations	OGE	OGE
52	KLU082–01	H2–0082–01	H2ercules Medelsheim-Mittelbrunn incl. M&R stations	NaTran_D/OGE	NaTran_D/OGE
53	KLU083–01	H2–0083–01	H2ercules Mittelbrunn-Gernsheim incl. M&R stations	NaTran_D/OGE	NaTran_D/OGE
54	KLU084–01	H2–0084–01	H2ercules Gernsheim-Rimpar incl. M&R stations	---	NaTran_D/OGE
55	KLU085–01	H2–0085–01	H2ercules Rimpar-Rothenstadt incl. M&R stations	---	NaTran_D/OGE
56	KLU086–01	H2–0086–01	H2ercules Rothenstadt-Waidhaus incl. M&R stations	NaTran_D/OGE	NaTran_D/OGE
57	KLU089–01	H2–0089–01	H2ercules St. Hubert-Glehn incl. M&R stations	OGE/Thyssengas H2	OGE/ Thyssengas H2
58	KLU090–01	H2–0090–01	H2ercules Glehn-Voigtslach incl. M&R stations	OGE/Thyssengas H2	OGE/ Thyssengas H2
59	KLU091–01	H2–0091–01	H2ercules Voigtslach-Paffrath incl. M&R stations	OGE/Thyssengas H2	OGE/ Thyssengas H2
60	KLU103–01	H2–0103–01	Wedringen 1-Glöthe pipeline incl. M&R stations	ONTRAS	ONTRAS
61	KLU113–01	H2–0113–01	Kleinziethen-Osdorfer Straße pipeline incl. M&R stations	---	ONTRAS
62	KLU114–01	H2–0114–01	Heidelberg-Heilbronn pipeline incl. M&R stations	terranets bw	terranets bw
63	KLU115–01	H2–0115–01	Heilbronn-Löchgau pipeline incl. M&R stations	terranets bw	terranets bw
64	KLU116–01	H2–0116–01	Löchgau-Altbach pipeline incl. M&R stations	terranets bw	terranets bw
65	KLU117–01	H2–0117–01	Bad Krozingen-Freiburg pipeline incl. M&R stations	---	terranets bw
66	KLU118–01	H2–0118–01	Hittistetten-Lindau pipeline incl. M&R stations	---	terranets bw
67	KLU119–01	H2–0119–01	Freiburg-March pipeline incl. M&R stations	---	terranets bw

68	KLU120–01	H2–0120–01	H2ercules Elten-St.Hubert incl. M&R stations	Thyssengas H2/OGE	Thyssengas H2/ OGE
69	KLU122–01	H2–0122–01	Uedemerbruch-Wardt pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
70	KLU127–01	H2–0127–01	Weiden-Marsdorf pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
71	KLU128–01	H2–0128–01	Stotzheim-Kalscheuren pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
72	KLU132–01	H2–0132–01	Hoeningen-Oberaußem pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
73	KLU139–01	H2–0139–01	Borna-Thierbach pipeline incl. M&R stations	---	ONTRAS
74	KLU140–01	H2–0140–01	Hüthum-Praest pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
75	KLU141–01	H2–0141–01	Stade-Götzdorf branch pipeline incl. M&R station	GUD	GUD
76	KLU142–01	H2–0142–01	Götzdorf-Stade pipeline incl. M&R station	GUD	GUD
77	KLU143–01	H2–0143–01	Weißenfelde-Harsefeld pipeline incl. M&R station	GUD	GUD
78	KLN001–01	H2–0201–01	Überackern-Haiming pipeline incl. M&R stations	bayernets	bayernets
79	——	H2–0203–01	Deffingen-Wasserburg pipeline incl. M&R stations	---	bayernets
80	——	H2–0204–01	Moosburg-Moosburg/Rosenau pipeline incl. M&R stations	---	bayernets
81	——	H2–0205–01	Münchsmünster-Regensburg pipeline incl. M&R stations	---	bayernets
82	——	H2–0206–01	Line Ulm-Augsburg pipeline incl. M&R stations	---	bayernets
83	——	H2–0207–01	Moosburg/Rosenau-Moosburg/Lände pipeline incl. M&R stations	---	bayernets
84	——	H2–0209–01	Kötz-Günzburg pipeline incl. M&R stations	---	bayernets
85	——	H2–0211–01	Kadeltshofen-Weißenhorn pipeline incl. M&R stations	---	bayernets
86	——	H2–0212–01	Weißenhorn-Weißenhorn pipeline incl. M&R stations	---	bayernets
87	——	H2–0213–01	Weißernhorn-Bellenberg pipeline incl. M&R stations	---	bayernets
88	——	H2–0214–01	Isarschiene Ost pipeline incl. M&R stations	---	bayernets/ Energy Networks Bavaria
89	——	H2–0215–01	Isarschiene West pipeline incl. M&R stations	---	bayernets/Energie netze Bayern
90	——	H2–0218–01	Birlinghoven-Beuel pipeline incl. M&R stations	---	OGE

91	——	H2–0224–01	Dernbach Elgendorf-Bendorf pipeline incl. M&R stations	---	OGE
92	——	H2–0225–01	Bendorf-Bendorf South pipeline incl. M&R stations	---	OGE
93	——	H2–0226–01	Niederkassel-Wesseling pipeline incl. M&R stations	---	OGE
94	——	H2–0231–01	Freiburg-Weier pipeline incl. M&R stations	---	terranets bw
95	——	H2–0233–01	Uedemerbruch-Wardt pipeline incl. M&R stations	---	Thyssengas H2
96	——	H2–0244–01	Aachen-Soers pipeline incl. M&R stations	---	Thyssengas H2
97	——	H2–0247–01	Neuss-Neuss pipeline incl. M&R stations	---	Thyssengas H2
98	——	H2–0248–01	Dormagen-Nievenheim pipeline incl. M&R stations	---	Thyssengas H2
99	——	H2–0249–01	Neuss Port-Düsseldorf Port pipeline incl. M&R stations	---	Thyssengas H2/ OGE
100	KLN002–01	H2–1002–01	Bissingen-Wertingen pipeline incl. M&R stations	---	bayernets
101	KLN003–01	H2–1003–01	Kötz-Hittistetten pipeline incl. M&R stations	---	bayernets
102	KLN005–01	H2–1005–01	H2-BAL, Niederhohndorf-Ronneburg/Rückersdorf section, incl. M&R stations	---	Long-distance gas
103	KLN006–01	H2–1006–01	H2-BAL, Waidhaus-Arzberg section incl. M&R stations	---	Long-distance gas
104	KLN007–01	H2–1007–01	H2-BAL, Arzberg-Niederhohndorf/Zwickau section, incl. M&R stations	---	Long-distance gas
105	KLN008–01	H2–1008–01	HYROW (Rostock-Wrangelsburg) incl. M&R stations	GASCADE	GASCADE
106	KLN009–01	H2–1009–01	Pipeline AQD Offshore SEN 1-AQD Offshore 1 incl. M&R stations	AquaDuctus Pipeline Ltd.	GASCADE
107	KLN010–01	H2–1010–01	Pipeline AQD Offshore 1-AQD Onshore incl. M&R stations	AquaDuctus Pipeline GmbH	GASCADE
108	KLN011–01	H2–1011–01	HYBHC (AWZ D Baltic Sea-Lubmin) incl. M&R stations	GASCADE	GASCADE
109	KLN012–01	H2–1012–01	HYMI (Edesbüttel-Bobbau) incl. M&R stations	GASCADE	GASCADE
110	KLN013–01	H2–1013–01	HYLU (Lampertheim-Ludwigshafen) incl. M&R stations	GASCADE	GASCADE/OGE
111	KLN014–01	H2–1014–01	HYKA (Ludwigshafen-Karlsruhe) incl. M&R stations	GASCADE	GASCADE/OGE
112	KLN017–01	H2–1017–01	Huntorf-Elsfleth 2 pipeline incl. M&R station	---	GTG

113	KLN020–01	H2–1020–01	Elsfleth-Bremerhaven pipeline incl. M&R station	---	GTG
114	KLN021–01	H2–1021–01	Heist-Klein Offenseth pipeline incl. M&R station	GUD	GUD
115	KLN026–01	H2–1026–01	Ganderkesee-Achim pipeline incl. M&R station	GUD	GUD
116	KLN028–01	H2–1028–01	Brunsbüttel-Hemmingstedt pipeline incl. M&R station	---	GUD
117	KLN030–01	H2–1030–01	Luttum/Lehringen-Edesbüttel pipeline, incl. M&R station	---	GUD
118	KLN038–01	H2–1038–01	H2ercules North Sea-Ruhr Link (NRL IV) incl. M&R stations	OGE/GASCADE	OGE/GASCADE
119	KLN039–01	H2–1039–01	H2ercules North Sea-Ruhr Link (NRL V) incl. M&R stations	---	OGE
120	KLN040–01	H2–1040–01	Bottrop-Gladbeck pipeline incl. M&R stations	---	OGE
121	KLN041–01a	H2–1041–01a	H2ercules Belgium incl. M&R stations	OGE	OGE
122	KLN041–01b	H2–1041–01b	H2ercules Belgium incl. M&R stations	---	OGE
123	KLN042–01	H2–1042–01	Delta Rhine Corridor (DRC) incl. M&R stations	---	OGE
124	KLN043–01	H2–1043–01	H2ercules Gernsheim incl. M&R stations	---	OGE
125	KLN044–01	H2–1044–01	Wiesbaden-Frankfurt pipeline incl. M&R stations	OGE	OGE
126	KLN045–01	H2–1045–01	AQD Dornum-Emden area incl. M&R stations	AquaDuctus Pipeline GmbH	GASCADE
127	KLN046–01	H2–1046–01	H2ercules North Sea-Ruhr Link (NRL II) incl. M&R stations	AquaDuctus Pipeline GmbH	GASCADE
128	KLN047–01	H2–1047–01	H2ercules Rothenstadt-Forchheim incl. M&R stations	NaTran_D	NaTran_D
129	KLN052–01	H2–1052–01	H2ercules Krefeld-Neumühl incl. M&R stations	---	OGE/ Thyssengas H2
130	KLN053–01	H2–1053–01	H2ercules Neumühl-Werne incl. M&R stations	---	OGE/ Thyssengas H2
131	KLN054–01	H2–1054–01	H2ercules Werne-Hamm incl. M&R stations	---	OGE/ Thyssengas H2
132	KLN055–01	H2–1055–01	Rostock-Glasewitz pipeline incl. M&R stations	---	ONTRAS
133	KLN056–01	H2–1056–01	Buchholz-Friedersdorf pipeline incl. M&R stations	---	ONTRAS
134	KLN057–01	H2–1057–01	Friedersdorf-Hennickendorf pipeline incl. M&R stations	---	ONTRAS
135	KLN058–01	H2–1058–01	Ketzin-Havelland Canal pipeline incl. M&R stations	---	ONTRAS

136	KLN059–01	H2–1059–01	Havelland Canal-Falkenhöh pipeline incl. M&R stations	---	ONTRAS
137	KLN060–01	H2–1060–01	Line Stäbchen-Eisenhüttenstadt incl. M&R stations	---	ONTRAS
138	KLN061–01	H2–1061–01	Eisenhüttenstadt-Gosda pipeline incl. M&R stations	---	ONTRAS
139	KLN062–01	H2–1062–01	Gosda-Spreetal pipeline incl. M&R stations	---	ONTRAS
140	KLN063–01	H2–1063–01	Salzgitter-Wefensleben pipeline incl. M&R stations	ONTRAS	ONTRAS
141	KLN064–01	H2–1064–01	Preußlitz-Cörmigk pipeline incl. M&R stations	ONTRAS	ONTRAS
142	KLN065–01	H2–1065–01	Pipe Cörmigk Hall incl. M&R stations	ONTRAS	ONTRAS
143	KLN073–01	H2–1073–01	Eisenhüttenstadt-Fürstenberg (PL) pipeline incl. M&R stations	---	ONTRAS
144	KLN074–01	H2–1074–01	HYSO (Schönermark-Schwedt) incl. M&R stations	GASCADE	GASCADE
145	KLN075–01	H2–1075–01	HYPOL (Schwedt-Greifenhagen (PL) incl. M&R stations	GASCADE	GASCADE
146	KLN076–01	H2–1076–01	Rostock Laage-Fliegerhorst Laage pipeline incl. M&R stations	---	ONTRAS
147	KLN077–01	H2–1077–01	Werben-Kleinziethen pipeline incl. M&R stations	---	ONTRAS
148	KLN078–01	H2–1078–01	Böhlen-Borna pipeline incl. M&R stations	---	ONTRAS
149	KLN079–01	H2–1079–01	Kitzen-Böhlen pipeline incl. M&R stations	---	ONTRAS
150	KLN081–01	H2–1081–01	Uhrsleben-Wefensleben pipeline incl. M&R stations	---	ONTRAS
151	KLN082–01	H2–1082–01	Lampertheim-Heidelberg pipeline incl. M&R stations	terranets bw	terranets bw
152	KLN083–01	H2–1083–01	Altbach-Bissingen pipeline incl. M&R stations	---	terranets bw
153	KLN084–01	H2–1084–01	Fessenheim-Bad Krozingen pipeline incl. M&R stations	---	terranets bw
154	KLN086–01	H2–1086–01	Wardt-Xanten pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
155	KLN089–01	H2–1089–01	Oberaußem-Weiden pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
156	KLN090–01	H2–1090–01	Marsdorf-Stotzheim pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
157	KLN091–01	H2–1091–01	Kalscheuren-Wesseling pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
158	KLN092–01	H2–1092–01	Oberhausen-Neumühl pipeline incl. M&R stations	---	Thyssengas H2

159	KLN093–01	H2–1093–01	Dormagen-Merkenich pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
160	KLN094–01	H2–1094–01	Recklinghausen-Leverkusen pipeline incl. M&R stations	---	Thyssengas H2
161	KLN095–01	H2–1095–01	Rinkerode-Uentrop pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
162	KLN096–01	H2–1096–01	Spellen-Wesel pipeline incl. M&R stations	Thyssengas H2	Thyssengas H2
163	KLN097–01	H2–1097–01	GETH2 Frensdorfer Bruchgraben-Frenswegen incl. M&R stations	Thyssengas H2/Nowega	Thyssengas H2/ Nowega
164	KLN098–01	H2–1098–01	Werne-Eisenach pipeline incl. M&R stations	---	Thyssengas H2
165	KLN100–01	H2–1100–01	Dorsten-Recklinghausen pipeline incl. M&R stations	---	Thyssengas H2/ OGE
166	KLN102–01	H2–1102–01	Hennickendorf-Rüdersdorf pipeline incl. M&R stations	ONTRAS	ONTRAS
167	KLN103–01	H2–1103–01	Herzfelde-Alt Rüdersdorf pipeline incl. M&R stations	---	ONTRAS
168	KLN104–01	H2–1104–01	H2ercules Neumühl-Bruckhausen incl. M&R stations	---	OGE/ Thyssengas H2
169	KLN107–01	H2–1107–01	HYBOR (Bobbau-Rückersdorf) incl. M&R stations	GASCADE	GASCADE
170	—	H2–1201–01	Strohreit-Reitmehring pipeline incl. M&R stations	---	bayernets/ Energy Networks Bavaria
171	—	H2–1202–01	Völkerberg-Augsburg/sewage treatment plant pipeline incl. M&R stations	---	bayernets/ Swabia regional network
172	—	H2–1214–01	Broichweiden-Aachen pipeline incl. M&R stations	---	Thyssengas H2
173	—	H2–1215–01	Kirchpuetz-Weisweiler pipeline incl. M&R stations	---	Thyssengas H2
174	—	H2–1216–01	Breinig-Broichweiden pipeline incl. M&R stations	---	Thyssengas H2
175	—	H2–1218–01	Nievenheim-Neuss pipeline incl. M&R stations	---	Thyssengas H2
176	—	H2–1219–01	Neuss Harbour-Neuss pipeline incl. M&R stations	---	Thyssengas H2/ OGE
177	KVS001–01	H2–2001–01	Haiming compressor station (KN)	---	bayernets
178	KVS002–01	H2–2002–01	Ellund compressor station (KN)	---	GUD
179	KVS003–01	H2–2003–01	Achim compressor station (KN)	GUD	GUD
180	KVS004–01	H2–2004–01	Compressor station Bunde (KN, 1.2)	---	GUD/OGE
181	KVS005–01	H2–2005–01	Compressor station Gescher (KN)	---	OGE
182	KVS006–01	H2–2006–01	Brühl compressor station (KN)	---	OGE
183	KVS008–01	H2–2008–01	Seyweiler compressor station (KN, 1.2)	---	NaTran_D/OGE

184	KVS010–01	H2–2010–01	Greifenhagen compressor station (KN)	---	OGE/GASCADE/ GUD
185	KVS011–01	H2–2011–01	Ochtrup compressor station (KN,1,2)	---	Thyssengas H2
186	KVS012–01	H2–2012–01	Elten compressor station (KN)	---	Thyssengas H2/OGE
187	KVS007–01	H2–2109–01	Compressor station Forchheim (1,2)	bayernets	bayernets
188	KVS009–01	H2–2110–01	Friesland compressor station (1,2)	---	GASCADE
189	—–	H2–2154–01	Total cross-border IPs Compressor network expansion proposal	---	---
190	AND025–01	H2–3025–01	Erlangen-Tennenlohe-Nuremberg pipeline (N-Ergie) incl. M&R stations	N-ERGIE Netz GmbH	N-ERGIE Netz GmbH
191	AND026–01	H2–3026–01	Esslingen-Esslingen pipeline incl. M&R stations	Netze BW GmbH	Netze BW GmbH
192	AND027–01	H2–3027–01	Esslingen-Esslingen pipeline incl. M&R stations	Netze BW GmbH	Netze BW GmbH
193	AND028–01	H2–3028–01	Esslingen-Altbach pipeline incl. M&R stations	Netze BW GmbH	Netze BW GmbH
194	AND029–01	H2–3029–01	Altbach-Altbach pipeline incl. M&R stations	Netze BW GmbH	Netze BW GmbH
195	AND041–01	H2–3041–01	Line Hamburg South-Hamburg Central incl. M&R stations	Hamburger Energienetze GmbH	Hamburger Energienetze GmbH
196	AND042–01	H2–3042–01	Line Hamburg South-Hamburg Centre incl. M&R stations	Hamburger Energienetze GmbH	Hamburger Energienetze GmbH
197	AND043–01	H2–3043–01	Line Hamburg South-Hamburg Central incl. M&R stations	Hamburger Energienetze GmbH	Hamburger Energienetze GmbH
198	AND044–01	H2–3044–01	Line Hamburg South-Hamburg Centre incl. M&R stations	Hamburg Energy Networks Ltd	Hamburger Energienetze GmbH
199	AND045–01	H2–3045–01	Line Hamburg South-Hamburg East incl. M&R stations	Hamburger Energienetze GmbH	Hamburger Energienetze GmbH
200	AND068–01	H2–3068–01	Coswig-Dresden pipeline incl. M&R stations	SachsenNetze HS.HD GmbH	SachsenNetze HS.HD GmbH
201	AND071–01	H2–3071–01	Klein Offenseth-Brunsbüttel pipeline incl. M&R stations	Schleswig-Holstein Netz AG	Schleswig-Holstein Netz AG
202	AND088–01	H2–3088–01	Finsing-Ismaning North pipeline incl. M&R stations	bayernets	bayernets
203	AND089–01	H2–3089–01	Ismaning North-Münchsmünster pipeline incl. M&R stations	bayernets	bayernets
204	AND093–01	H2–3093–01	Fürstenhausen-Fenne pipeline incl. M&R stations	Creos Germany Wasserstoff GmbH	Creos Germany Hydrogen GmbH
205	AND096–01	H2–3096–01	Leidingen-Dillingen pipeline incl. M&R stations	Creos Deutschland	Creos Deutschland Wasserstoff GmbH

				Wasserstoff GmbH	
206	AND097–01	H2–3097–01	Perl-Besch pipeline incl. M&R stations	Creos Deutschland Wasserstoff GmbH	Creos Deutschland Wasserstoff GmbH
207	AND098–01	H2–3098–01	March-Freiburg pipeline (RHYn Interco) incl. M&R stations	badenovaNETZE GmbH	badenovaNETZE GmbH
208	AND099–01	H2–3099–01	Waldshut-Tiengen-Grenzach pipeline incl. M&R stations	badenovaNETZE GmbH	badenovaNETZE GmbH
209	AND102–01	H2–3102–01	Seyweiler-Dillingen pipeline incl. M&R stations	Creos Deutschland GmbH	Creos Germany Ltd
210	AND106–01	H2–3106–01	Blumberg-Berlin-Mitte pipeline incl. M&R stations	NBB Netzgesellschaft Berlin-Brandenburg mbH & Co. KG	NBB Netzgesellschaft Berlin-Brandenburg mbH & Co. KG
211	AND107–01	H2–3107–01	Berlin-Lichterfelde-Berlin-Wilmersdorf pipeline incl. M&R stations	NBB Netzgesellschaft Berlin-Brandenburg mbH & Co. KG	NBB Netzgesellschaft Berlin-Brandenburg mbH & Co. KG
212	AND109–01	H2–3109–01	Berlin-Biesdorf-Berlin-Marzahn pipeline incl. M&R stations	NBB Netzgesellschaft Berlin-Brandenburg mbH & Co. KG	NBB Netzgesellschaft Berlin-Brandenburg mbH & Co. KG
213	AND113–01	H2–3113–01	Merkenich-Merkenich (Rhine) pipeline, incl. M&R stations	RheinNetz GmbH	RheinNetz GmbH

Source: Coordination Office for Gas and Hydrogen Network Development Planning

Appendices

Appendix 1: Execution status of measures from the last NDP and the hydrogen core network (tables showing the status of the network expansion measures)

Appendix 2: Assignment of expansion measures to the criteria for the methane network expansion proposal

Appendix 3: Assignment of expansion measures to the criteria for the hydrogen network expansion proposal

Appendix 4: Hydrogen network detail measures plan

Glossary

Glossary

Transmission system operators

Aqua Ductus Pipeline	Aqua Ductus Pipeline GmbH
bayernets	bayernets GmbH
Ferngas	Ferngas Netzgesellschaft Limited
Fluxys	Fluxys TENP GmbH
Fluxys D	Fluxys Deutschland GmbH
GASCADE	GASCADE Gastransport GmbH
GTG Nord	Gas Transport North GmbH
GUD	Gasunie Deutschland Transport Services GmbH
LBTG	Lubmin–Brandov Gas Transport GmbH
NaTran_D	NaTran Deutschland GmbH
NGT	NEL Gas Transport Ltd.
Nowega	Nowega Limited
OGE	Open Grid Europe GmbH
ONTRAS	ONTRAS Gas Transport GmbH
terranets	terranets bw GmbH
Thyssengas	Thyssengas Limited
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
cFAC (temp)	Conditionally firm, freely allocable capacity (temperature-dependent)
BKartA	Federal Cartel Office
BNetzA	Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railways
BVEG	Federal Association of Natural Gas, Oil and Geoenergy
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CGHI	Czech-German Hydrogen Interconnector
CH_4	Methane
dena	German Energy Agency
DN	Nominal diameter
DP	Design pressure
DVGW	German Technical and Scientific Association for Gas and Water
DAC	Dynamically allocable capacity
ENTSO–G	European Network of Transmission System Operators for Gas
EnWG	German Energy Industry Act
EU	European Union
EUGAL	European Gas Interconnector
fDAC	Fiirm, dynamically allocable capacity
FID	Final Investment Decision
TSO	(Gas) gas transmission system operators
FSRU	Floating storage and regasification units
FAC	Freely allocable capacity
GasNZV	Regulation on access to gas supply networks/Gas Network Access Regulation
M&R station	Gas metering and pressure regulation station
CTS	Trade/commerce/services
Green gases	Hydrogen and synthetic methane
GTP	Gas network area transformation plan
GTS	Gasunie Transport Services B.V.
CCGT	Combined-cycle gas turbine
Cross border IP	Cross-border interconnection point
GWe	Electrical (connection) rating in gigawatts
GWh	Gigawatt hour

GWh/h	Gigawatt hours per hour
GY	Gas year
GWth	Thermal (connection) capacity in gigawatts
H_2	Hydrogen
H-gas	Methane with a high calorific value
CHP	Combined heat and power plant
ID	Identification number
INES	Initiative Energien Speichern e.V.
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
Inlet compressor	Compressor unit used at cross-border IPs to increase the inlet pressure into the gas pipeline system and to ensure gas transportation
KSG	Federal Climate Protection Act
KW	Power plant
CHP	Combined heat and power
L-gas	Methane with a low calorific value
LH_2	Liquid hydrogen
LTF	Long-term forecast by distribution system operators
LFC	Load flow commitment
LNG	Liquefied natural gas
Loop line	Pipeline laid parallel to an existing pipeline
MBI	Market-based instrument
MEGAL	Mittel-Europäische Gasleitung(sgesellschaft)
MWh	Megawatt hour
NC CAM	Network Codes Capacity Allocation Mechanisms
NEL	Nordeuropäische Erdgas–Leitung (North European Gas Pipeline)
NDP	Network Development Plan
NIP	Network interconnection point
NRL	Nordsee–Ruhr–Link (North Sea-Ruhr Link)
OPAL	Ostsee-Pipeline-Anbindungsleitung (Baltic Sea Pipeline Connection Pipeline)
PCI	Project of Common Interest
PHH	Private households

PMI	Projects of Mutual Interest
PtG	Power-to-gas
RLM	Registered demand measurement
PGU	Power generating unit
SektVO	Sector Regulation – Regulation on the award of public transport, drinking water supply and energy supply contracts
SEL	Süddeutsche Erdgasleitung (South German Natural Gas Pipeline)
Main line compressor	Compressor unit used in a transmission pipeline to compensate for pressure losses and ensure the transportation of gases
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
eTSO	Electricity transmission system operator
CS	Compressor station
VTP	Virtual trading point
VIP	Virtual Interconnection Point
VKU	Association of Municipal Companies
DSO	Distribution system operator
DSO-HCNO	Distribution system operator/hydrogen core network operator
WassBG	Hydrogen Acceleration Act
WEB	Hydrogen production and demand survey
WKL	Wilhelmshaven–Küsten–Leitung (Wilhelmshaven Coastal Pipeline)
HTNO	Hydrogen transmission network operator
HCNO	Hydrogen core network operator

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