Safe Hydrogen Injection Modelling and Management for European gas network Resilience

D4.3 Recommendations of mixing strategies and infrastructure needs

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ABSTRACT

The European natural gas infrastructure provides the opportunity to accept feeding in hydrogen (H_2), as a measure to integrate low-carbon gases while leveraging the existing gas network and contributing to decarbonization. Within subtask 4.2 of SHIMMER, SINTEF has developed and implemented extensions of the energy system optimization model EMX to do dedicated analyses on timing and sizing of infrastructure investment to facilitate the phasing in and transportation of hydrogen supply in natural gas networks. The model has been applied to case studies in the project to perform analyses of transmission networks in Norway and in Spain. Our main findings include the following:

- Hydrogen admixing can be a cost-effective option for delivering significant volumes of hydrogen, but the potential is closely interrelated with the need for natural gas transport.
- The transported volumes of natural gas often limit how much hydrogen can be injected when considering hydrogen blending limits. Dependent on policy and market incentives, gas flows may be routed differently to accommodate higher levels of hydrogen admixing.
- For transporting large hydrogen volumes, dedicated pipelines are preferred.
- High opportunity cost of natural gas exports is a barrier for repurposing pipelines to pure hydrogen transport. As the need for natural gas transport is reduced, repurposing becomes more attractive.
- Buffer storages for hydrogen can be used to shift injection of hydrogen from variable production in time and exploit the capacity of existing natural gas for admixing
- With premium H_2 prices, deblending can be used to extract extra revenue and stay below terminal blending limits if the upstream network has higher capacity for admixing.

AUTHORSHIP AND APPROVAL INFORMATION

AUTHOR(S)
Lars Hellemo / SINTEF
Ruud Egging-Bratseth / SINTEF
Raquel Alonso Pedrero / SINTEF

DATE / SIGN

Lars Hellemo (Aug 20, 2026 12:55:34 GMT+2)

REVIEWED BY WP-LEADER
Huib Blokland / TNO

DATE / SIGN

Huib Blokland

Huib Blokland (Aug 24, 2026 13:43:18 GMT+2)

APPROVED BY COORDINATOR
Martin Fossen / SINTEF
Diana Gonzalez / SINTEF

DATE / SIGN

Diana González

Diana Gonzalez (Aug 24, 2026 13:45:12 GMT+2)

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List of Abbreviations

Table 0.1: List of abbreviations

Term	Explanation
BBV	Barcelona-Bilbao-Valencia (gas corridor)
CAPEX	Capital Expenditures
CH_4	Methane CH_4 (main component of natural gas)
EMGN	EnergyModelsGasNetworks - Julia extension for gas network modelling
EMX	EnergyModelsX - open-source energy system modelling framework
ETS	EU Emissions Trading System (for CO_2 emission permits)
H_2	Hydrogen (H_2)
HV	Higher Heating Value
LHV	Lower Heating Value
LMA	Langsiktig Markedsanalyse (long-term market analysis, Statnett)
MEUR	Million Euros
MILP	Mixed-Integer Linear Program
MSm3/d	Million standard cubic metres per day
MWh	Mega Watt Hours
NCS	Norwegian Continental Shelf (gas production)
NG	Natural Gas
Nm3	Normal cubic meter (at 0°C and 1 atm)
NPV	Net Present Value
OPEX	Operational Expenditures
PoliTO	Politecnico de Torino
PSA	Pressure Swing Adsorption (H_2 separation process)
PWA	Piecewise-Affine approximation
RES	Renewable Energy Source
RP	Representative Period (seasonal archetype in the model)
SHIMMER	Safe Hydrogen Injection Modelling and Management for European netwoRks
Sm3	Standard cubic meter (at 15° C and 1 atm)
SP	Strategic Period (investment decision horizon)
TTF	Title Transfer Facility - Dutch natural gas price hub
UGS	Underground Gas Storage

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Executive Summary

This document describes and discusses the analyses and results performed by SINTEF AS in subtask 4.2.1 System Design and Capacities of the SHIMMER project. In this subtask, SINTEF has extended the optimization modelling tool EMX to do dedicated analyses on timing and sizing of infrastructure investment to facilitate the phasing in and transportation of hydrogen supply in natural gas networks in Norway and in Spain. To this end, we have developed input data sets based on a mix of public data and internal project data. These data sets are documented in this report.

In the analyses, the model may consider investing in dedicated new hydrogen pipelines, investing in repurposing existing natural gas pipeline for dedicated hydrogen transport, admixing of hydrogen in natural gas pipelines, dedicated hydrogen storage, compressor stations, and deblending of hydrogen out of mixed natural gas hydrogen streams. The variety in investment options allows the optimization model to customize the infrastructure build-out over time to maximally benefit from relative costs, price and volume developments.

The case study of the Norwegian network considers a part of the offshore pipeline network on the Norwegian Continental Shelf. Hydrogen production from renewable sources will be introduced adjacent to a natural gas injection location and we consider an extensive range of production and price scenarios of hydrogen and natural gas to show how different assumptions affect the investment choices in different types of assets. For larger hydrogen volumes, the model suggests building new dedicated transport capacity for hydrogen export, while for more moderate hydrogen volumes different variations of building new capacity and blending with natural gas are chosen. Under the assumptions in the case study, deblending units increase the potential of hydrogen transport via blending as it allows both reducing the percentage of hydrogen in the mix before reaching terminals with stricter constraints on hydrogen percentage and selling the extracted hydrogen at a premium price.

Scenarios with fast ramping up to large hydrogen volumes with high profit margins for hydrogen will typically result in early construction of a dedicated hydrogen pipeline, and extra compression capacity or extra deblending capacity can be added later to accommodate increased volumes over time. This so-called *staged development* demonstrates that there can be some flexibility in development of transport capacity despite the need to fix pipeline dimensions at the time of investment. The amount of natural gas transport volumes can however also limit the amount of hydrogen that may be injected, and in scenarios with very little natural gas transport, dedicated corridors either by new pipelines or repurposing may be necessary. Consolidation of remaining natural gas flows into fewer pipelines can be a cost saving strategy as the volumes of natural gas are reduced. Across scenarios, we hardly see repurposing of pipelines because natural gas transport capacity is simply needed throughout the entire planning horizon. Only if at the receiving ends of different pipelines the markets would develop very differently (i.e., one would relatively rapidly move to a hydrogen economy), repurposing could be foreseen. However, in a larger network, e.g., with multiple pipelines serving the same final market (Norpipe, Europipe I and Europipe II) it may be feasible more quickly to repurpose pipes in a staged fashion. However, given the reliance of Northwest European importers on Norwegian natural gas, the time needed for a repurposing implementation and the implied decrease in natural gas flows might be longer than importers can manage.

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The case study of the Spanish network considers an onshore regional transmission network around the area of Zaragoza. We consider three locations for hydrogen injection with optional investment in buffer storages to smoothen injection over time and an optional deblending unit before the injection into the underground seasonal storage in the region. We represent different operations of the network over the year by introducing both seasonal variations between summer and winter, injection from regasification terminals outside the case study network from two directions, as well as daily patterns with variations in hydrogen production.

While buffer storages are useful and indeed shift hydrogen injection into the network over the day, the hydrogen injection rates are fundamentally limited by the volumes of natural gas in the network (the availability of natural gas for hydrogen injection.) For larger volumes of hydrogen, alternatives not considered in the Zaragoza case study would be needed, for instance, dedicated hydrogen transport modes or local consumption.

About the project: The European natural gas infrastructure provides the opportunity to accept hydrogen (H_2), as a measure to integrate low-carbon gases while leveraging the existing gas network and contributing to decarbonisation. However, there are technical and regulatory gaps that should be closed, adaptations and investments to be made to ensure that multi-gas networks across Europe will be able to operate in a reliable and safe way while providing a highly controllable gas quality and required energy demand. Aspects such as material integrity of pipelines and components, as well as the lack of harmonisation of gas quality requirements at European level must be addressed in order to facilitate the injection of hydrogen in the natural gas network.

In this context, the SHIMMER project (Safe Hydrogen Injection Modelling and Management for European gas network Resilience) was selected for funding as part of the 2023 Clean Hydrogen Partnership programme. SHIMMER aims to enable a higher integration of low-carbon gases and safer H_2 injection management in multi-gas networks by strengthening the knowledge base and improving the understanding of risks and opportunities in H_2 projects.

It will do this by:

- Mapping and assessing European gas T&D infrastructure in relation to materials, components, technology, and their readiness for hydrogen blends.
- Defining methods, tools and technologies for multi-gas network management and quality tracking, including simulation, prediction, and safe management of network operation in view of widespread hydrogen injection in a European-wide context.
- Proposing best practice guidelines for handling the safety of hydrogen in the natural gas infrastructure and managing the risks.

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1 Introduction

This chapter introduces the content of the report, giving the background and motivation for the work performed as part of Task 4.2, subtask 4.2.1 System Design and Capacities.

1.1 Purpose of the document

The purpose of this document is to give recommendations about mixing strategies and infrastructure needs for various hydrogen phasing-in scenarios considering existing natural gas networks. We present insights into investment decisions and operational strategies relevant to gas network operators. The basis for the insights and recommendations are results from analysing network expansion case studies performed using the optimisation model extension developed in the SHIMMER project in Task 4.2, subtask 4.2.1.

This report also documents how the EMX extension EnergyModelsGasNetworks (EMGN) can be applied on realistic network configurations and economic data, which has been demonstrated on a large-scale sensitivity analysis across a large number of economic and operational scenarios. It also briefly documents model improvements and fixes identified during the application to the realistic case studies.

1.2 Intended readership

The intended audience for this document is analysts working on injection strategies for Transmission System Operators (TSOs), members of the academic community with an interest in gas transport infrastructure development in general and evaluating hydrogen admixing in natural gas transport networks in particular, and policy makers and regulating authorities in the energy field.

Readers are expected to have prior knowledge of how gas transmission networks and how they are typically operated. Some familiarity with mathematical optimization is an advantage, but not a requirement to read the report. However, the software tool EMX is intended for expert users with familiarity with optimization software and tools for infrastructure design and planning.

1.3 Structure of this document

The remainder of this document is structured as follows. Chapter two provides a background of the work based on a brief description of the SHIMMER project and an explanation of possible hydrogen injection strategies and potential needs for infrastructure development. Chapter three presents the EMX modelling framework and the newly developed model extension EnergyModelsGasNetworks which is used in the analysis of the case studies. The first case study considering the Norwegian Offshore Natural Gas Network, where the Norwegian Gas TSO Gassco has been the main industry partner is presented in Chapter four. Chapter five presents the second case study, which is geographically placed near Zaragoza in Spain, and where Spanish TSO Enagás has been the main industry partner. Both chapters provide the network topology and input data assumptions, describe the setup of the EMX model for the specific case, provide and discuss results for a range of scenario variants. Chapter six provides an integrated discussion and insights based on observations from both case studies. Chapter seven concludes and provides generalizable recommendations. Used references are listed in Chapter eight.

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1.4 Stakeholder involvement

Stakeholders of this work package have shown great interest in the work and contributed with their experience and expertise to complement our academically oriented work in reaching the goals of the work package. Specifically, the gas transmission operators have been involved in selecting and prioritising both the case studies and the most relevant analyses, guiding the prioritisation of functionality for the software extension during dedicated workshops in the consortium meetings and dedicated technical workshops and dedicated meetings to follow up the analyses and discussions during consortium meetings. Research partners have contributed to the development of the model extension in providing validation by comparing with results obtained with the SHIMMER++ tool by PoliTO and interoperability of data formats from TNO.

1.5 Relationship with other deliverables

The case studies presented in this document are based on two cases developed for the project and developed in D4.1 in task T4.1 and presented in the report D4.1 *Report describing the defined simulated test cases, realistic scale testcase(s), and available operational models including required data set and format* [1]. Parts of the network descriptions for the case studies in sections 4 and 5 are revised versions of the corresponding sections of D4.1. Validation studies have been performed using a selection of test cases and with the tool SHIMMER++ described in D4.4 Open-source fluid-dynamic model with gas quality tracking released with handbook and tutorials [2]. The software used in this document (D4.3 *Recommendations of mixing strategies and infrastructure needs*) was presented in the report D4.2: *Tool for infrastructure optimization: Investments and Capacity* [3].

1.6 AI Declaration

In the preparation of this report, we have used AI (GitHub Copilot Claude Sonnet 4.6) support to propose first drafts for some subsections. These have since been revised and rewritten manually. AI support has also been used for EMX code revisions and debugging, setting up sensitivity analyses and developing code to plot result visualisations. All suggestions have been revised and quality assured and the analysis of results is performed by the authors.

2 Background

This chapter gives the background for the work in Work Package 4 on Flow Assurance, specifically in Task 4.2, subtask 4.2.1 System Design and Capacities, and how it can contribute to analysing injection strategies and infrastructure development needed to support the integration of hydrogen while leveraging the existing gas network and contributing to reaching European decarbonization targets.

2.1 Injection strategies

With the EMX optimization tool that can consider both network modifications and operational concerns such as pressure set points, we can investigate injection strategies that depend on investment in the transport pipeline infrastructure. Investment may be in new infrastructure and in repurposing existing natural gas infrastructure for dedicated hydrogen transport.

Here it is possible to impose certain strategies, or to let the optimization model decide an optimal investment pathway considering supply, demand and price trajectories for hydrogen and natural gas. For example, the strategy of injecting hydrogen into an existing natural gas pipeline as an intermediate solution before building a dedicated pipeline for hydrogen can be considered; the model will suggest the timing of the investment in the new dedicated transport pipeline if it is worthwhile, depending on investment costs (CAPEX), operational expenses (OPEX) and prices and demand levels.

To help respect hydrogen blending limits, buffer storages can be used to manage intermittent production of renewable hydrogen. This is another example of how the model can be used to investigate different strategies. How much storage capacity is needed, given assumptions on production profiles, quality bounds for the blend in the network, and costs.

Deblending facilities may extract hydrogen from a mixed gas flow. The viability of blending hydrogen into natural gas pipelines for transport, followed by deblending to meet more stringent local blending limits or sell pure hydrogen can also be analysed.

2.2 Infrastructure development

We may blend hydrogen into natural gas volumes considering blending limits and consider new investment and retrofitting of existing natural gas pipelines to transport hydrogen. Which solution(s) are optimal depends on investment costs (CAPEX), operational expenses (OPEX) and the development of supply, demand and price levels over time. Economies of scale can make it more interesting to invest in larger capacity at once, but investing later will reduce capital costs (due to the discount rate). Blending hydrogen may displace natural gas, hence the relative costs and prices (or rather, the relative profit margin) will highly affect the volumes of hydrogen transported, and possibly also how they will be routed through the network.

Dedicated hydrogen pipelines will typically require large volumes to be worthwhile investing in. Repurposing (retrofitting) existing natural gas pipelines for hydrogen transport will typically only be interesting if natural gas demand will decline rapidly. For smaller volumes of hydrogen, blending them into natural gas volumes can be an interesting solution, also as a bridging solution when hydrogen volumes are expected to increase. This can delay the outlay of capital costs on the one hand and possibly allow benefiting from economies of scale at a later stage.

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Deblending of hydrogen out of the natural gas stream can be beneficial if final consumers have a high willingness to pay for pure hydrogen. It can also be necessary if final consumers (or storages) require natural gas with a lower hydrogen blending percentage than the blending limits imposed in the network. As deblending tends to be relatively costly, there must be clear cost or price incentives to make this beneficial. Reduced capital costs for pipeline investment are a possible incentive.

Buffer hydrogen storages provide temporary storage of hydrogen to manage intermittency of hydrogen production driven by variable renewable power generation and help control adherence to the blending limits in other infrastructure or final delivery points. Here we may expect that buffer storage will be needed in several cases, but there may several options on where such buffer storages could be placed in the network, and our analysis should provide insight in optimal placement.

The next chapter provides a description of the EMX modelling framework that has been extended and applied in this subtask.

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3 About EMX and EnergyModelsGasNetworks

The optimisation model developed in subtask 4.2.1 is implemented as an extension to EnergyModelsX (EMX) [4], an open-source energy systems modelling framework. EnergyModelsGasNetworks adds support for pressure-flow relationship and tracking of gas composition to EMX. The software is released under an open-source licence and is available in a GitHub repository[1] along with online documentation.[2]

EMX is a library of software packages developed at SINTEF for energy systems analyses. EMX is open source and freely available on GitHub.[1] EMX is developed using the open-source Julia programming language[3] and the JuMP modelling language for optimization.[4] Both the core packages that have been developed in previous projects and the published extensions developed in the SHIMMER project can be easily installed using the Julia package manager.

EMX can be used to study the operation of networked systems with multiple energy carriers and technologies for generation, conversion, transport, etc., and demands for different energy carriers or energy services. The system operation is typically optimized to serve the demand at the lowest possible cost while maintaining the operational constraints. Examples of operational constraints that can be handled by the EMX framework are, for instance, generation and transport capacities and minimum level of demand satisfaction. Infrastructure development, or “network expansion”, considers the minimization of the net present value of the total costs of current and future decisions, accounting for the operational costs and technical requirements required to meet energy demand for different carriers such as power, gas, or hydrogen.

While many energy systems models only allow very simplified technology descriptions, assuming linear costs and capacities with exogenously fixed parameter values (e.g. CAPEX, OPEX, capacities, loss rates), the modular design of EMX gives users the capability to easily add new network characteristics such as more detailed descriptions of technologies. In SHIMMER, SINTEF Industry has developed the EMX extension EnergyModelsGasNetworks which implements a detailed representation of flow-pressure relationships and tracking of gas composition. This allows performing analyses where pipeline capacity in one part of the network is influenced by the operation in another part of the network through shared pressure dependencies. This is a major strength compared to the fixed capacities typically assumed in energy systems models.

EMX supports tracking the gas composition (gas quality) in the networks by modelling explicitly the mixing of gas with different qualities in different parts of the network. Modelling this properly for general network topologies requires non-linear constraints or binary variables which greatly increases the complexity of the mathematical model structure, and therefore also the time needed to find optimal solutions.

Because hydrogen molecules are much lighter than natural gas, when it is blended into natural gas, the properties of the gas mix flowing through the network change, and the relation between

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[1] https://github.com/EnergyModelsX/

[2] https://github.com/EnergyModelsX/EnergyModelsGasNetworks.jl

[3] https://julialang.org/

[4] https://jump.dev/

compression and volume and flow speed changes. Therefore, not only the transported amount of energy changes, but also the capacity in terms of maximum cubic meter throughput per time period.

The new package EnergyModelsGasNetworks uses combinations of linear lines (piecewise-affine approximation, PWA) to approximate flow capacity under various pressure levels while considering changing gas properties throughout the network due to admixing (blending) of hydrogen in the natural gas networks. Figure 3.1 shows how well a non-linear function can be approximated by PWA.

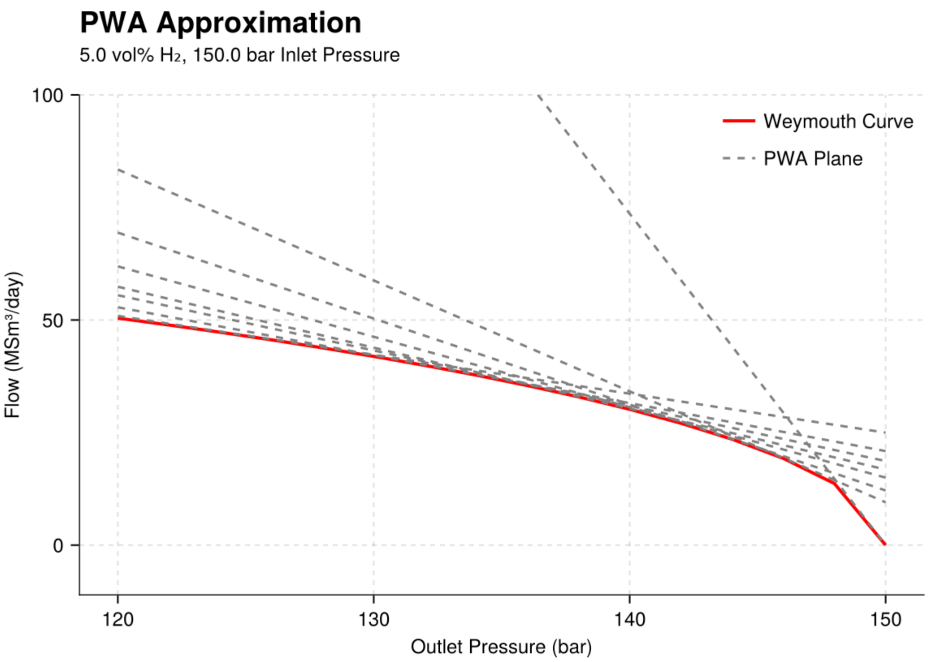

Figure 3.1: Example of piecewise-affine approximation of the Weymouth function. The dashed lines are upper bounds that together define the piece-wise affine concave curve marked in red. Specific pipeline with fixed inlet pressure of 150 bars, a fixed volumetric hydrogen ratio of 0.05.

Compared with more detailed simulation models, EnergyModelsGasNetworks still relies on other simplifications and approximations, but optimization is meant to offer a different type of decision support. Simulation models provide insight in detailed operational characteristics. In contrast, EnergyModelsGasNetworks can optimize the design of the network (e.g. adding pipelines or compressors), considering how it should be operated by suggesting pressure level set points and flows.

Several of the characteristics that should be considered in the analyses and hence in the modelling are known to make optimization models hard to solve. Some characteristics make models (potentially) non-convex or result in a so-called combinatorial explosion. Both affect computational tractability as they can make it challenging for a solver to efficiently consider the feasible region (the solution search space), and can result in long solution times.

Sometimes we can simplify the model for specific case studies because we know things about the structure of an optimal solution based on the input data and network topology. For instance, if a node has only one incoming pipeline, the blending percentage in all pipelines leaving that node will be the same as in the incoming pipeline. Or if hydrogen is blended into a gas pipeline, we can precompute

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the blending percentage in the gas pipeline. Imposing this knowledge about an optimal solution in the model as hard constraints will reduce the search space and can improve performance.

Especially hard are the non-convex non-linear constraints needed to model mixing of flows with different blending percentages in pooling nodes. In the large scale case studies we have opted to only allow a set of discrete blending percentage levels, and a continuous level. Instead of modelling the pooling problem with continuous variables, we restrict the model to choose between a set of allowed blending percentages. The granularity of this discretisation can be configured by the user, and is using binary variables, which can be handled relatively efficiently by MILP solvers. Open-source solvers like HiGHS can be used with this reformulation as well, but commercial solvers like Gurobi, CPLEX or Xpress typically provide better performance.

Whereas the Weymouth equation by itself can be linearized and precomputed for operational set points in a network, having large variability in operational scenarios including multi-component flows requires trading off representative accuracy and computation time.

To get insight in how much accuracy we may lose by simplifying mathematical expressions to improve the computational tractability we apply sensitivity analysis and compare solutions for both formulations (see section 4.11).

For more information about EnergyModelsGasNetworks, please refer to the report *D4.2 Tool for infrastructure optimization: Investments and Capacity*, and the online documentation for EnergyModelsGasNetworks. For more information about EnergyModelsX in general, please see [4] and the comprehensive online documentation.

The base framework operates over a time structure consisting of strategic periods (SPs) - multi-year investment horizons - within which representative periods (RPs) capture seasonal variability. Each RP contains a sequence of operational time steps. Investment decisions are made at the SP level, while operational decisions (flow scheduling, storage dispatch) are made at the RP/time-step level. This structure allows cost-efficient long-term planning while retaining sufficient operational resolution to include the main physical constraints.

3.1 Blend Gas Quality Tracking (Pooling Problem)

In natural gas networks carrying H2-CH_4 blends, the gas composition varies from node to node depending on injection points and mixing along the network. EMGN implements a generalised pooling problem formulation that tracks the proportion of each gas component (H2 and CH_4) at every node. At blending nodes, incoming flows mix linearly so the outgoing composition is the flow-weighted average of all incoming streams. In contrast with blending nodes that only have one outgoing pipeline and can be modelled with linear constraints, pooling nodes enforce perfect mixing before splitting the flow into multiple outgoing pipelines. These pooling constraints are the source of the non-linearities in the model. Quality bounds (minimum and maximum H_2 fraction) can be applied at nodes and links to enforce blend limits, typically at terminals to satisfy contractual obligations or at border crossings to satisfy regulatory constraints.

3.2 Pressure-Flow Constraints (Weymouth Equation)

For gas transmission modelling, the relationship between flow, inlet pressure, and outlet pressure is a key physical constraint. EMGN uses a linearised version of the Weymouth equation for

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compressible gas flow in pipelines. The Weymouth constant depends on gas composition: H_2 has lower specific gravity than CH_4, so blending H_2 increases the effective flow capacity of a pipeline under fixed pressure conditions.

EMGN reformulates the Weymouth constant to separate composition-independent and composition-dependent terms, then linearises the resulting nonlinear pressure-flow-composition surface using a piecewise-affine (PWA) approximation based on tangent planes. This yields a pure MILP formulation (no nonlinear programming terms) solvable with standard commercial MILP solvers. The number of tangent-plane breakpoints controls the approximation accuracy, with 5-7 planes typically giving less than 1% error.

3.3 Investment Optimisation

Investment decisions can be formulated in different ways, for the case analyses in SHIMMER we use the following two modes:

Continuous investment: capacity can be sized at any level from zero to a specified asset-specific maximum, allowing the model to find the optimal scale without minimum commitment.

Binary investment: capacity is either built at design capacity or not at all, reflecting the all-or-nothing nature of major infrastructure projects such as offshore pipelines. By allowing alternative investments with different capacities and costs, economies of scale can be modelled correctly, e.g. by using higher cost per capacity for smaller pipelines.

In addition to the capital expenditure (CAPEX) discussed above, the model also considers selected operational expenditures (OPEX). In EMX a variety of both variable and fixed operational costs can be included. For the case studies in SHIMMER we mainly consider the production cost of hydrogen, the power cost, and the revenue from sales of hydrogen and natural gas.

The model maximises total net present value (NPV) across all strategic periods subject to physical and operational constraints.

3.4 Time Structure

The model employs a hierarchical time structure with three period levels, as summarized in Table 3.1. Strategic periods provide the moments where investment decisions are made. Seasonal representative periods allow to model operational characteristics that mainly vary at a seasonal scale, such as seasonal gas storage, offshore wind speeds, or solar radiation. Each seasonal representative period consists of a set of operational periods, which allow to model more detailed operational characteristics such as flow and dispatch. The seasonal and operational characteristics inform the strategic decisions, while at the same time the seasonal and operational period decisions are optimized in conjunction with the strategic period decisions.

Table 3.1: Hierarchical time structure in EMGN

Level	Description	Typical duration	Role
Strategic Period (SP)	Long-term investment horizon	One year (scaled up to 5-10 years)	Investment decisions; NPV accounting

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Level	Description	Typical duration	Role
Representative Period (RP)	Seasonal archetype	One week (scaled up to represent ~6 months)	Captures summer/winter variation
Operational Period (OP)	Individual time steps within RP	Hours (scaled up for the to match the containing period)	Flow scheduling, storage dispatch

As an example, EMX has a CyclicStrategic storage type that allows charge and discharge between representative periods (e.g., charging in summer RP, discharging in winter RP), subject to a net-zero constraint over the full strategic period. This enables representation of seasonal storage without requiring explicit full-year time series, keeping the model tractable for large networks. In the analyses we have used for Gassco: 4 SP, 2 RP, 1 OP per RP; for Enagás: 1 SP, 6 RP, 4 OP per RP.

The EMX package that allows the flexible definition of the three different types of model periods is called TimeStruct.jl [5] and allows to extend to more elaborate time structures as well as modelling of uncertainty.

3.5 Model improvements

The EMX extension EnergyModelsGasNetworks was presented in full detail in deliverable D4.2 and will not be repeated here. Please refer to D4.2 or the online documentation for more information.

During the work on the cases studies some issues related to computational tractability when scaling up to larger problem surfaced. For instances with a larger number of strategic and operational periods, each period effectively multiplies the number of variables and constraints needed for each problem instance. Some targeted reformulations and approximations were considered to improve the size of problems that could be solved within a reasonable time frame for a large-scale sensitivity analysis as described in this report.

The main improvements that were implemented after the release of EnergyModelsGasNetworks can be summarised as follows:

1. **Subcomponent flow pooling formulation**. The flow of hydrogen and methane are modelled explicitly between each node rather than being inferred from the source. This simplifies the formulation for nodes that use or modify the gas composition, e.g. to do deblending, convert to energy equivalents or set limits on hydrogen content.
2. **Discriminate between blending nodes (linear) and pooling nodes (bilinear)**. To apply as few non-linear/bilinear terms as possible, we are more explicit when constructing the model to only apply the non-linear terms where strictly needed and achieve less redundancy.
3. **Compressor work** depending on pressure lift and flow. A more realistic estimate of compressor work depending linearly on both pressure lift and flow, improving on the initial compressor model depending on pressure lift only. A full non-linear compressor model is outside the scope of the SHIMMER project.

[5] https://github.com/sintefore/TimeStruct.jl

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4. **Discretization of hydrogen fractions**. Using a discrete approximation for the hydrogen fraction out from any pooling node can be selectively applied and leverages the high performance of mature solvers for MILP problems. This comes at the cost of some inaccuracy but can be remedied by increasing the granularity of the discretisation as needed. This allows performing a higher number of sensitivities within the same time frame. Selected problem instances can be re-solved using the more accurate formulation as needed by changing a parameter.

The two first reformulations are mathematically equivalent to the originally implemented formulation, and the discretisation granularity can be easily adjusted for desired accuracy. The new formulations will be added with proper documentation in the next release of EnergyModelsGasNetworks.

The next chapter describes the first case study analysed in this subtask, North Sea / Gassco.

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4 Case Study 1: North Sea/Gassco

The Norwegian government has ambitious goals for developing offshore wind on the Norwegian continental shelf. In 2020, the areas of Sørlige Nordsjø and Utsira Nord were opened for license applications and in 2024 the call for project proposals was open for interested production firms to apply. Following these plans, offshore wind power generated in Sørlige Nordsjø and Utsira Nord was considered for the Norwegian realistic case. Small-scale green hydrogen projects are currently in the early stages of development, so limited information is available to be considered in SHIMMER. The possible development paths for Norwegian hydrogen production are therefore based on the assumptions in analyses by the Norwegian TSO Statnett in their long-term market analysis (LMA). For this study we assume that hydrogen may be exported by pipeline to continental Europe by pipelines from onshore production.

Gassco AS, a state-owned company, is the operator of the Norwegian offshore gas transport system, responsible for transporting approximately 120 billion Sm3/year of natural gas from the Norwegian Continental Shelf (NCS) to receiving terminals in Germany (Dornum), France (Dunkerque), the UK, and Belgium, and an offshore delivery point to Denmark and Poland. At present, Norway the largest gas exporter to Europe, and also a natural candidate for large-scale green hydrogen production using offshore wind, leveraging its extensive existing pipeline infrastructure. Gassco manages a large network of processing plants, pipelines, platforms, and gas terminals. The company plays a critical role in capacity management and infrastructure development of the gas transport network - which is currently spanning over 8,800 kilometres.

The Gassco case in SHIMMER investigates the optimal strategy for transporting H_2 produced on the Norwegian mainland to continental European markets. The main questions we try to answer in this case study:

1. What mixing strategies are recommended for the case of exporting hydrogen from renewable production via pipelines from Norway?
2. What infrastructure would be needed to support these mixing strategies, and which capacities?

To address these questions, we use EMX with EnergyModelsGasNetworks to evaluate several competing or complementing strategies:

1. Dedicated hydrogen export corridors to serve hydrogen market
2. Blending hydrogen with natural gas to serve natural gas market with premium
3. Blending hydrogen with natural gas and deblend after transport to serve both hydrogen markets and natural gas markets and extract a larger premium on the hydrogen

While there is large uncertainty about the future European hydrogen markets, to investigate different transport strategies we assume for this study that there is a market for hydrogen with premium prices (compared to energy prices for natural gas), and that there is a premium on natural gas with hydrogen due to the reduction in emissions. There is also a market for natural gas, and the model seeks to maximize the value of the total energy exports, including the main costs of developing new infrastructure to support the selected strategies.

The research leading to these results has received funding from Horizon Europe, the European Union's Framework Programme for Research and Innovation under grant agreement n° 101111888.

4.1 Network Description

The model represents a simplified Norwegian gas export network as a graph of five principal nodes connected by investable and existing pipeline links (see Figure 4.1). This network includes:

- Two natural gas export terminals (Kårstø and Kollsnes), two receiving terminals (Dunkerque and Dornum), and a platform with blending and routing opportunities (Draupner).
- We assume all hydrogen production is available for export at Kårstø, and necessary pipeline and compressor capacity to export the hydrogen will need new investments.
- For exporting hydrogen, a new dedicated pipeline from Kårstø to Draupner can be constructed. Several different dimensions, each with associated capacity and cost, will be considered.
- The existing pipeline Europipe I from Draupner to Dornum is considered for repurposing to a dedicated hydrogen pipeline. Repurposing Europipe I will render it unavailable for further export of natural gas after the repurposing.
- A dedicated hydrogen pipeline from Kårstø to Dornum can be constructed. Several dimensions will be considered, but all smaller than the one considered in previous studies for large-scale hydrogen export from natural gas reforming with carbon capture and storage.

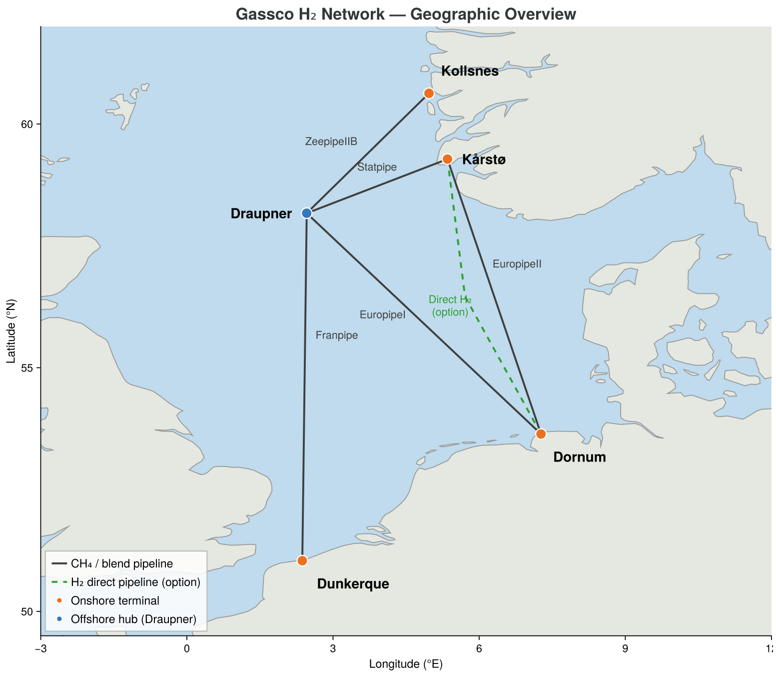

Figure 4.1 The subset of the network in the North Sea considered in the case study.

We assume that natural gas can be blended with hydrogen up to 20% hydrogen in the transport network but additionally can be subject to contractual or regulatory constraints at the terminals. The hydrogen production at Kårstø is based on the Clean Hydrogen to Europe (CHE) project in the sense that Kårstø will be a major export point for hydrogen. The CHE project targets a production

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capacity of around 0.45 Mtpa (or 15 TWh/year [6]) of blue hydrogen by 2030, using natural gas plants combined with Carbon Capture and Storage (CCS). We consider (green) hydrogen, and our scenario variants consider between 5 and 30 TWh of hydrogen. The Aukra Hydrogen Hub (AHH) which explores opportunities for blue hydrogen production in Nyhamna (about 600 km further north) at a similar scale is not considered.

In Task 4.1 of SHIMMER, Gassco has provided comprehensive details on a specific part of its network. Gassco recently considered the possibility of building infrastructure for pure hydrogen transportation from the Norwegian export terminals to Germany. This case study takes some inspiration from the concepts considered there, concentrating on the infrastructure for export from Norway and with different options at different scales and including the option of building a new dedicated pipeline from Kårstø to Draupner that may be used together with repurposing of the existing Europipe I for hydrogen export.

The Gassco case study network covers only a subset of the main Norwegian export pipeline system from the NCS to continental European receiving terminals. Table 4.1 lists the key elements in the network.

Table 4.1: Key elements in the reduced Gassco network – Short list – Basic model representation

Node	Role
Kollsnes	Natural gas export
Kårstø	Natural gas export and Hydrogen injection
Draupner	Offshore pooling and routing hub
Dornum	German landing terminal
Dunkerque	French landing terminal

4.1.1 Investment Options

We consider the following investment options in the various investment cases.

- Construction of a new pipeline dedicated to hydrogen parallel to Statpipe [Statpipe_H_2]
- Repurposing of Europipe I for dedicated Hydrogen transport [EuropipeI_H_2]
- Construction of a new pipeline dedicated Hydrogen transport [KarstoDornum_H_2]
- Construction of a new compressor to pressure a new pipeline [Kårstø Compressor H_2]
- Deblending facilities at the landing terminals in Dornum and Dunkerque [PSA Deblend]

Table 4.7 in section 4.7.4 lists the pipelines variants that are considered for investment in terms of diameters and capacities.

4.2 Technical characteristics and cost data

Unit conversion

- standard cubic meters measured at: 15°C & 1.01325 bar (Gassco & EU convention)
- For volumetric conversions we use kWh per Sm3 *Lower Heating Value* (LHV), see Table 4.2

[6] 0.45 mtpa = 0.45 x 10^9 kg = ; 0.45 x 10^9 kg x 33.33 kWh/kg = 15 x 10^9 kWh = 15 TWh

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- For market prices we consider energy content as € / MWh *Higher Heating Value* (HHV)

Table 4.2: Unit conversion assumptions

Energy carrier	LHV [kWh/Sm3]	HHV [kWh/Sm3]
Natural gas (CH_4)	10	11.11
Hydrogen (H_2)	2.8	3.31

4.3 Pipelines – CAPEX & OPEX

Investment costs for the pipelines are based on two sources. We have used the Gassco/Dena study [5] as the source for lengths and main concepts, considering a new pipeline for hydrogen from Kårstø to Draupner, and repurposing Europipe I. In addition, we have added smaller pipeline options that better match the volumes from renewable production rather than the volumes from reformation of natural gas that was the basis for the Gassco/Dena study. We use estimates from the European Hydrogen Backbone (EHB) [6] study as the source for unit costs.

When considering EHB, the investment costs can be summarized as follows:

CAPEX [MEUR] = length [km] x D [inches] x MultOffsh x MultRepurp x 0.09 [MEUR/km/inch]

Wherein:

- MultOffsh is the offshore multiplier, which has value 1.0 for onshore pipelines and a value of 1.7 for offshore pipelines.
- MultRepurp is the repurposing multiplier, which has a value 1.0 for new pipelines, a value of 0.2 for repurposing pipelines with a diameter larger than 20 inches, and a value of 0.3 for repurposing pipelines with a diameter not larger than 20 inches.
- Capacity of pipelines have been scaled proportionally to diameter to the power 2.5: $K \sim D^{2.5}$
- For KarstoDornum_H_2 the pipeline with diameter 20 inches represents the capacity needed to transport the entire high scenario hydrogen production from 30 GWh (around 21 MSm3/d).

The operating costs for pipelines are given by the energy consumption of the compressors multiplied by the (local) energy carrier price. While this may be electricity or natural gas, we assume in the analyses that compressors are subject to the Norwegian power prices in the LMA scenarios.

4.4 Compressors – Technical characteristics, CAPEX & OPEX

The compression investment costs for a newly constructed dedicated hydrogen pipelines must be included in the CAPEX. Here, we allow to add compressor capacity over time (in continuous increments), so that a larger diameter pipeline can be constructed then necessary for early transport needs, and throughput the planning horizon transport capacity can be increased by adding more compression capacity.

Open data on compressor costs for high pressure, large volume compressors for hydrogen is sparse, however according to EHB compression capacity costs about 4 MEUR/MW. Values from German BNA (2025) [7] are a bit higher, up to 7.7 MEUR/MW, but this considers smaller compression

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stations. BNA (2025) does not indicate throughput volumes. Hydrogen compressors may be 10%-15% more expensive than gas compressors.

Assuming compressor work in the range of 3-3.5 MW/MSm^3/d and cost per MW installed capacity of 4 MEUR, we use 14 MEUR/MSm^3 installed capacity for dimensioning of compressor capacity for hydrogen compressors. The OPEX related to compressor operations in the model are based on power consumption and is linked to both pressure lift and flow through the compressors to match the assumed power consumption at the design capacity (medium capacity for the natural gas production scenarios, 12 MSm^3/d). The operational cost of the compressor use thus depends both on the volume through the compressor, the increase in pressure, and the power price in each scenario.

4.5 PSA Deblending

Deblending facilities use pressure swing adsorption (PSA) separators to remove a specific gas (in our case hydrogen) from a mixed flow leading the gas through a bed of adsobant material in a pressure vessel. There are very few data points available for PSA deblending CAPEX or OPEX. For biogas we have found values around 2,800 €/Nm^3/h, for oxygen 1,290 €/Nm^3/h.[7] These values have the same order of magnitude. Scaling from hourly to daily rates means dividing CAPEX by 24, and having Nm^3 instead of Sm^3 means we need to add about 5.5%. This gives a PSA CAPEX value range indication of 60 - 125 MEUR/ MSm^3/d. However, a main component of CAPEX is investment in compressors and of OPEX the energy used for compression to pressurize the gas flow. However, since gas flows in pipelines are pressurized, this may mean that no or less compression is needed to push the gas through the PSA membranes. This would reduce CAPEX and possibly minimize OPEX. However, if gas needs to be repressurized to meet operational requirements, this may not hold.

We assume for deblending facilities (PSA separators), a unit CAPEX of 50 MEUR per MSm3/d H_2 capacity. This is a simplification, as the CAPEX will depend on the design of the PSA unit and for which percentage of H_2 is in the gas mix. We apply the same CAPEX for all blends within the range of 0-20% in the case study. To reflect OPEX, we set PSA recovery efficiency to 95% H_2 recovered relative to H_2 input embedded in the mixed gas flow volume into the PSA deblending facility.

4.6 End of horizon (salvage) value

We consider economic lifetimes of the different classes of assets as follows:

- Pipelines 60 years
- Compressors 24 years
- PSA deblending 20 years
- Storages 40 years

Any remaining life at the end of the study end is accounted for after discounting the original CAPEX to the final period as per standard in EnergyModelsInvestments. See Table 4.3 for examples of how

[7] https://repository.kaust.edu.sa/items/d1c95430-d73a-4eb0-b882-1e0112b1a5f4
https://slideum.com/doc/1258118/biogas_upgrading_with_the_carborex_ms_system_v2
https://www.berg-kompressoren.de/en/OXYBERG-1700-Oxygen-Generator-1020101700

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many years of lifetime will remain for an asset class with a lifetime of 40 years, depending on which period it is installed.

Table 4.3: Asset value at end of planning horizon when considering forty years lifetime

SP	Year invested	Remaining life at study end
SP1	2026	40−24 = 16 yr
SP2	2032	40−18 = 22 yr
SP3	2038	40−12 = 28 yr
SP4	2044	40−6 = 34 yr

4.7 Assumptions and Scenarios

The following tables provide information on scenarios for prices, hydrogen and natural gas ramping and production scenarios, and CAPEX for investment alternatives. OPEX are indicated in Section 4.2.

4.7.1 Price Scenarios (LMA)

For hydrogen, gas and carbon dioxide prices, three scenarios are used, aligned with the Norwegian long-term market analysis (LMA) from Statnett [8]. Prices are representative of the mid-2030s planning horizon are listed in Table 4.4

Table 4.4: LMA price scenarios used in the Gassco case study

		Gas price	H_2 price	(ETS) CO_2 price	Power price (compressors)
Scenario	**Period**	**EUR/MWh**	**EUR/MWh**	**EUR/tCO_2**	**EUR/MWh**
Low	SP1	22.17	106.96	85	43
	SP2	20	86.26	95	40
	SP3	15	71.42	100	35
	SP4	15	65.21	100	35
Medium	SP1	27.17	127.66	93	59
	SP2	25	96.61	115	55
	SP3	20	78.32	130	52
	SP4	20	72.11	130	52
High	SP1	34.67	175.97	109	75
	SP2	35	158.72	145	70
	SP3	30	151.13	152	67.4
	SP4	30	146.98	164	65

^SP1 (2026–2031), SP2 (2032–2037), SP3 (2038–2043), SP4 (2044–2049)

The three scenarios consider Low, Medium, and High price outlooks. The Gas Price is the sales price of natural gas at the receiving terminal in Dornum and Dunkerque. The H_2 price provides a premium relative to the natural gas price. The ETS price provides the price in EUR per ton CO2 emitted. This is used in the model to give a premium on the natural gas price corresponding to the reduction in emissions compared to pure natural gas.

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4.7.2 Natural gas production

Norwegian Continental Shelf gas production is projected to decline from its current peak over the 2025-2050 planning period. Historically, production has often been extended, and new resources found. Depending on the outlook for further extensions and new discoveries, three production scenarios based on projections from the Norwegian Petroleum Directorate [9] (using Figure 4.7 in that report) are used to scale production of natural gas export from Kårstø and Kollsnes and the resulting volumes are listed in Table 4.5:

Table 4.5: NCS gas production scenarios [MSm³/d]

Scenario	SP	Kårstø [MSm³/d]	Kollsnes [MSm³/d]
Low	SP1	38.6	95.2
	SP2	21	52.7
	SP3	9.8	24.5
	SP4	3.8	9.4
Medium	SP1	45.1	111.2
	SP2	37.8	95
	SP3	30.3	75.6
	SP4	21.5	53.4
High	SP1	48.3	119.1
	SP2	47.2	118.7
	SP3	38.2	95.2
	SP4	28.5	70.9

^SP1 (2026–2031), SP2 (2032–2037), SP3 (2038–2043), SP4 (2044–2049)

Volumes are scaled indiscriminately based on the projections from the Norwegian Petroleum Directorate for all Norwegian resources and represent a span from maintaining near current production levels followed by a gradual decline (high) to a fast collapse in production (low).

Operational representative periods impose a production profile such that the total annual production equals the annual value listed in Table 4.5.

4.7.3 H_2 Production

The Kårstø_H_2 production is determined from the LMA scenario (for the long-run production level). In addition, we apply H_2 ramp scenarios (controlling how quickly the LMA scenario level is reached within the 24-year planning horizon) for further sensitivities on availability of hydrogen in combination with the decline of natural gas production and export.

Maximum Norwegian H_2 production capacities are derived from the Statnett LMA 2024-50 electricity demand projections. The conversion from electricity demand to H_2 production uses (MSm³ = 10^6 Sm³ and TWh = 10^9 kWh):

MSm³/d = 10^3 × TWh/yr / 2.8 [kWh/Sm3] × / 365 [d/yr] × 70% [electrolyser efficiency.] Applied to base values 5, 15 and 30 TWh/y

The H_2 ramp scenario controls how many strategic periods it takes to reach full production. We assume three ramping scenarios, Slow, Medium, and Fast, which impose that H_2 production capacity reaches the maximum in two, three, or four strategic periods. For in-between periods we apply linear

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interpolation to determine H_2 capacity. Applying the ramping scenarios to the LMA scenarios results in nine H_2 production scenarios (Table 4.6)

Table 4.6: H_2 production scenarios

Scenario	Ramp	SP1 MSm³/d	SP2 MSm³/d	SP3 MSm³/d	SP4 MSm³/d
Low	Slow	0.93	1.85	2.78	3.71
	Medium	1.24	2.47	3.71	3.71
	Fast	1.85	3.71	3.71	3.71
Medium	Slow	2.78	5.56	8.34	11.12
	Medium	3.71	7.41	11.12	11.12
	Fast	5.56	11.12	11.12	11.12
High	Slow	5.56	11.12	16.67	20.29
	Medium	7.41	14.82	20.29	20.29
	Fast	11.12	20.29	20.29	20.29

4.7.4 Pipeline Cost

Pipeline lengths underlying the investment costs are based on Gassco/Dena (2023). Table 4.7 presents the implied investment costs per unit of capacity, based on the cost formula derived from EHB (2023) (ref. Section 4.3.)

All pipelines in the case are offshore, hence a CAPEX multiplier of 1.7 applies.

Table 4.7: CAPEX pipelines

Pipeline	Investment [multiplier]	Length [km]	D [inch]	Total MEUR [rounded]	Max capacity [H_2 MSm3/d]
Statpipe_H_2	New [1.0]	236	20	819	23.0
			18	737	17.7
			16	655	13.2
			14	573	9.4
EuropipeI_H_2	Repurposing [0.2]	667	40	820	122.0
KarstoDornum_H_2	New Investment [1.0]	845	20	2, 586	23.0
			18	2, 327	17.7
			16	2, 069	13.2
			14	1, 810	9.4

4.7.5 Contractual or regulatory constraints

To investigate how different mixing strategies may apply depending on what constraints are put on the hydrogen percentage that may be delivered at terminals, we perform a sensitivity analysis with a variation in limits on the allowed hydrogen content at terminals Dunkerque and Dornum. These constraints may represent contractual agreements or governmental regulations. While the base case is the current regime of 2% allowed hydrogen admixing, we consider in the study the following allowed percentages: 1%, 2%, 5%, 10%, or 20%.

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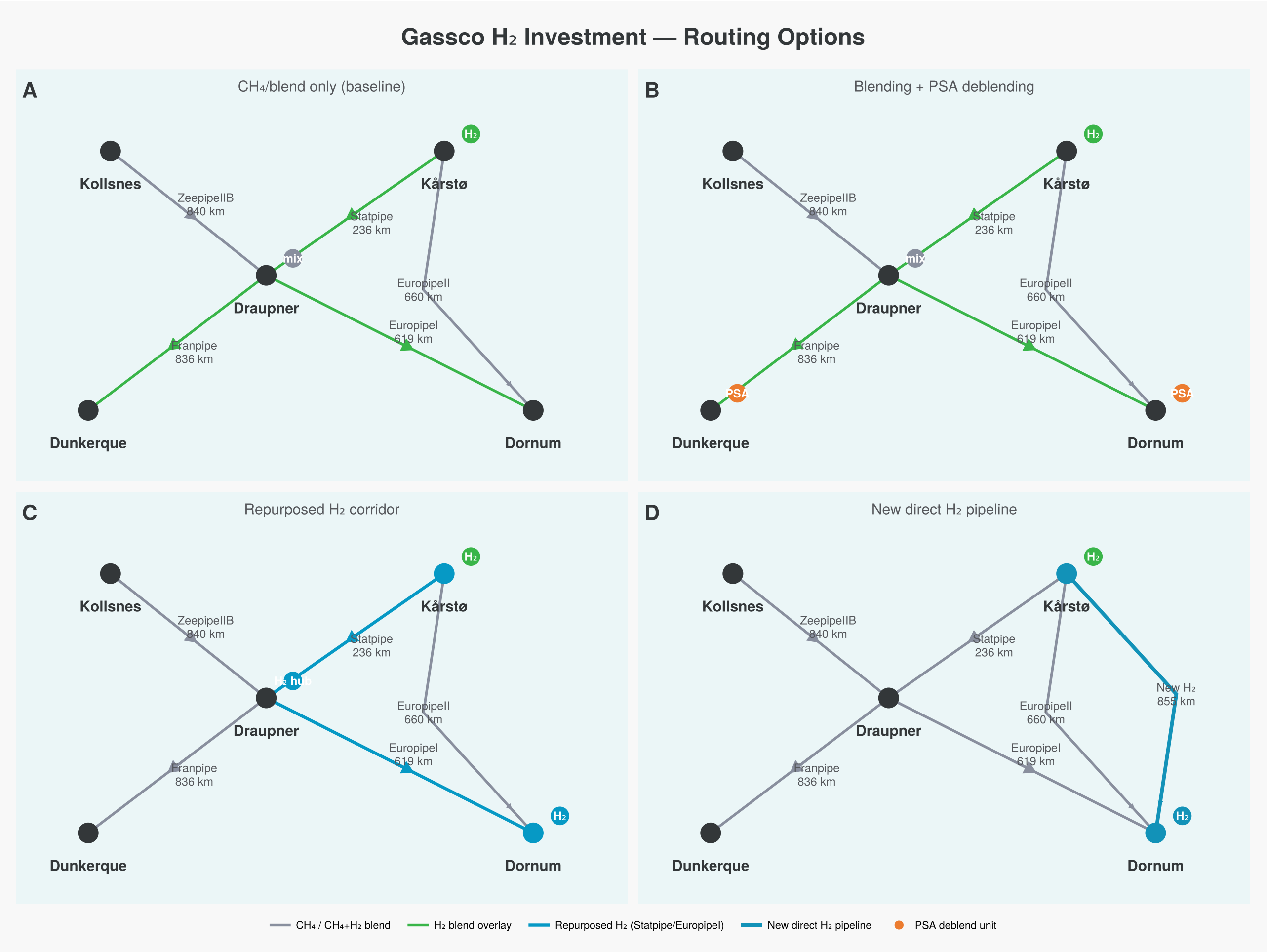
Note that in most of the model analyses, the actual blending percentages are discretised in 21 equi-distance steps from 0 to 20%, allowing 0%, 1%, 2% etc up to 20% delivered at the terminal. With the full non-linear formulation, any percentage in between can also be represented accurately.

4.8 Implementation details

Table 4.8: Implementation details Gassco case

Parameter	Value
Strategic periods	4 SP × 6 years each
Study horizon	24 years (2026–2050)
SP midpoints (base year 2026)	2029, 2035, 2041, 2047
Representative periods per SP	1
Operational time steps per RP	2
Discount rate	5%
Investment lifetime	20-60 years, depending on asset category (StudyLife with residual value)

The model configuration is summarized in Table 4.8. We consider varying hydrogen injection depending on the hourly production and solve the steady state energy maximization problem for each time period, selecting the optimal set points in terms of injection rates and pressure levels both at the entry points, but also throughout the network.



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The main routing options are:

1. Blending at Draupner and delivering at terminals with a premium due to ETS savings (A)
2. Blending and deblending at terminals to sell hydrogen at premium price (B)
3. Build new pipeline to Dornum and repurpose Europipe I for pure hydrogen (this reduces export capacity for natural gas when repurposing) (C)
4. Build new dedicated pipeline for hydrogen export from Kårstø to Dornum (D)

The infrastructure development opportunities considered by the model are:

- Dedicated pipeline Kårstø-Dornum
- Repurposing Europipe I
- Additional compression capacity for hydrogen export from Kårstø
- Deblending (PSA) at terminals

Note that the model supports staged development of the infrastructure, and may suggest e.g., doing blending in the first strategic period but only invest in deblending later, or investing in a larger diameter pipeline with somewhat limited compression capacity and expand compression capacity later when larger volumes become available. As we consider significant economies of scale in pipeline investment cost, this allows the model to consider a trade-off between larger investment at once to benefit from economies of scale against delaying investment to increase capacity (and thereby reducing discounted investment costs).

The model considers production capacities as upper limits and takes prices at the delivery terminals as given. There are no limits to the deliverable volumes at each terminal.

4.9 Investment results

For the analysis we will consider the 2% hydrogen admixing limit in the network under current regulations as the base case but otherwise explore the range of results for overall trends and possibly generalizable insights, as there is no combination of assumptions that stand out as more likely. In the below we refer to combinations of assumptions and scenario variants as *scenarios*.

The scenarios include variants that allow blending (but not deblending), blending and deblending, investment in repurposing and/or investment in new dedicated hydrogen pipelines). This section will give an overview of under which conditions specific options can be profitable and when not, according to the model and the assumptions described in more detail earlier.

For the scenarios with the most optimistic view on maintaining production and export of natural gas (NCS High), the model suggests investing in a dedicated pipeline for hydrogen. For scenarios with most optimistic outlook on hydrogen production (LMA High) the 18” pipeline is invested in, otherwise in the smaller 14” pipeline. The only exception is for the slow ramping in combination with Low LMA, where there is no investment in new pipelines.

The direct pipeline Kårstø-Dornum is the preferred option for a dedicated hydrogen pipeline in these cases. While the investment cost of repurposing Europipe I are lower than investing in the completely new pipeline, it has the disadvantage that natural gas supply volumes are forced down by lack of transport capacity. The opportunity cost of the natural gas transport/export are so high that giving up natural gas supply would come at a significant loss.

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Figure 4.2 illustrates how the pipeline diameter (and hence capacity) varies by scenario. Horizontally we have three variants for hydrogen ramping scenarios: Slow, Medium and Fast ramp. For each of the three hydrogen ramping scenarios, it considers three scenario variants combining LMA price scenarios and hydrogen volume scenarios, where both prices for gas, hydrogen, CO2 emission permits and compressor power electricity but also the eventual total hydrogen supply are Low, Medium, or High. Vertically it distinguishes the natural gas production scenarios.

Which capacity is chosen for a dedicated hydrogen pipeline is driven by the underlying hydrogen supply assumptions. If a capacity can be chosen that has minor overcapacity, then it will generally be invested in. However, if the unused capacity becomes too large, the model invests in a smaller capacity pipeline and blends the remaining hydrogen into the gas supply flows. When blending happens, only a high enough pure hydrogen premium will then make it profitable to invest in deblending to allow pure hydrogen deliveries. The high natural gas volumes allow distributed transport by blending due, but the total transport volume for hydrogen is limited by the 2% requirement at the terminal and dedicated infrastructure needed to transport large volumes of hydrogen.

Under less optimistic scenarios for natural gas transport (NCS Low and Medium), routing via Draupner is the preferred option. In many cases the model suggests building a new dedicated pipeline to Draupner without repurposing Europipe I, as the amount of hydrogen that can be blended at Draupner is a bottleneck considering the natural gas volumes in this pipeline (15MSm^3/d). While repurposing seems attractive as this investment option has lower cost than a dedicated pipeline, it is only selected in the scenarios where the blending potential in natural gas is too low to export via blending (Low NCS, Low LMA and strict blending constraints). The new hydrogen feeder to Draupner is combined with a richer mix of supporting blending strategies, depending on the scenario.

The assumed allowed hydrogen percentage at terminal drives the need for deblending, most pronounced when there is little natural gas available, as represented in the Low NCS scenarios.

Figure 4.2 presents the pipeline investments in the different stages for the 27 scenarios with a 2% blending limit. Moving from left to right in the figure we generally observe diameters becoming larger with higher prices and higher eventual hydrogen volumes.

Within each LMA scenario, there are notable variations between the ramping scenarios. In LMA Medium, the ramping speed has no impact on the timing and sizing of investments. However, when we consider compression capacity (ref. Figure 4.3) there are in fact significant differences. In LMA Low and LMA High there are more explicit variations due to hydrogen ramping speed in Figure 4.2.

The impact of the NCS scenario is substantial. As blending is the cheaper and more beneficial supply option, larger gas volumes facilitate lower-cost hydrogen supply. The most extreme situation in Figure 4.2 is LMA Low - NCS High, Slow H_2 ramping for which no construction of dedicated H_2 pipeline is needed.

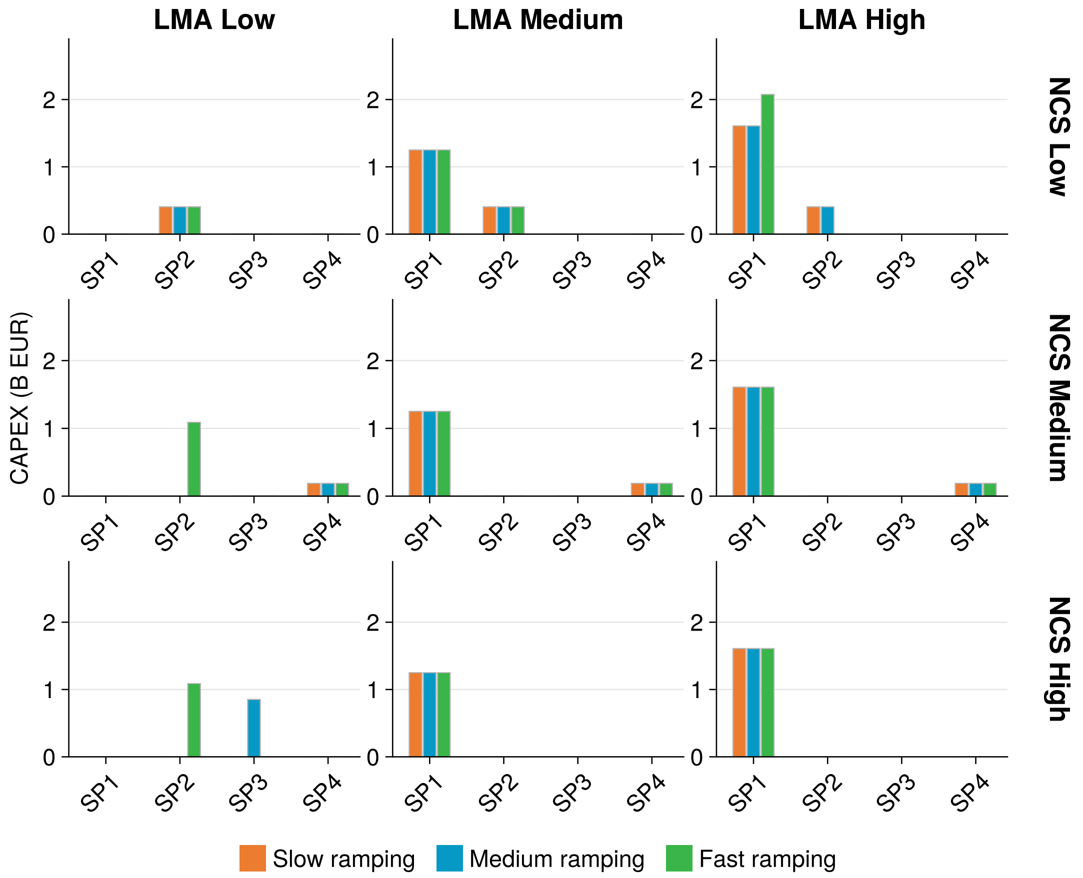

Figure 4.2: Staged pipeline investment (bln-€ discounted).
LMA and NCS scenarios and for each the three ramping scenarios (2% blending limit).

Even when Figure 4.2 shows several cases where the pipeline build-out is the same, the compressor build-out (in Figure 4.3) is not. Figure 4.3 shows how the development of compressor capacity can be adjusted in the model to accompany the availability of hydrogen for export.

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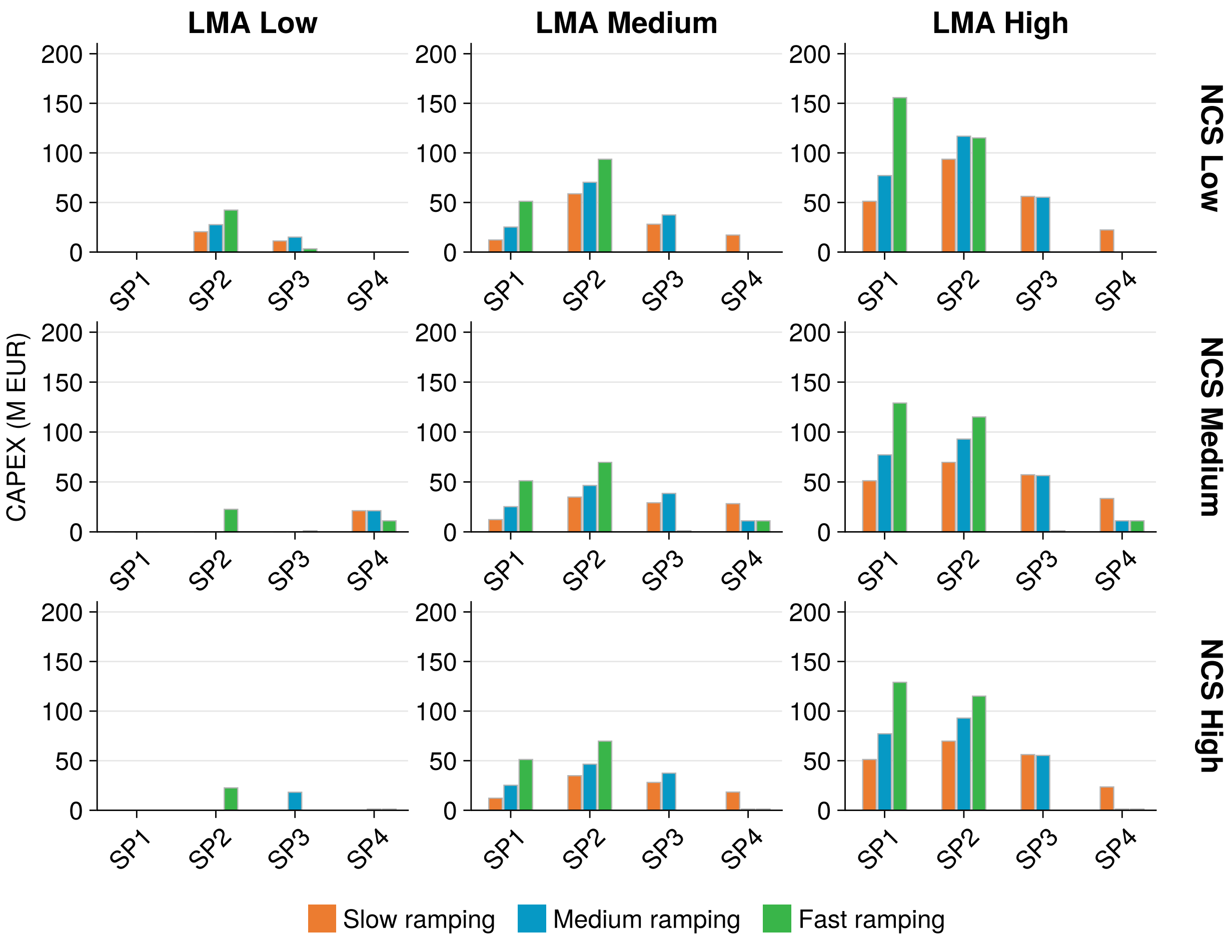

Figure 4.3: Staged investment compressor at Karstø (m-€). 2% blending limit.

In the case study, pipelines can be chosen from some discrete dimensions only, while compressor capacity and deblending can be dimensioned on a continuous spectrum. The model exploits this by investing early in the pipeline and the minimum compressor capacity needed, while delaying additional investment in additional compression capacity in time to expand export capacity. This can be seen clearly for the LMA High scenarios on the right pane of Figure 4.3, where the Slow ramping scenarios spread compressor investment more evenly over all strategic periods, while for the Fast ramping, the investment happens in the first two strategic periods, and the full capacity is reached in strategic period SP2. The gradual increase in compression capacity is most visible in the LMA Medium and LMA High scenarios. In the LMA Low scenarios, the potential for blending (and deblending) is so large that pipeline and compressor investment can be delayed (or in the most extreme case is not needed at all.)

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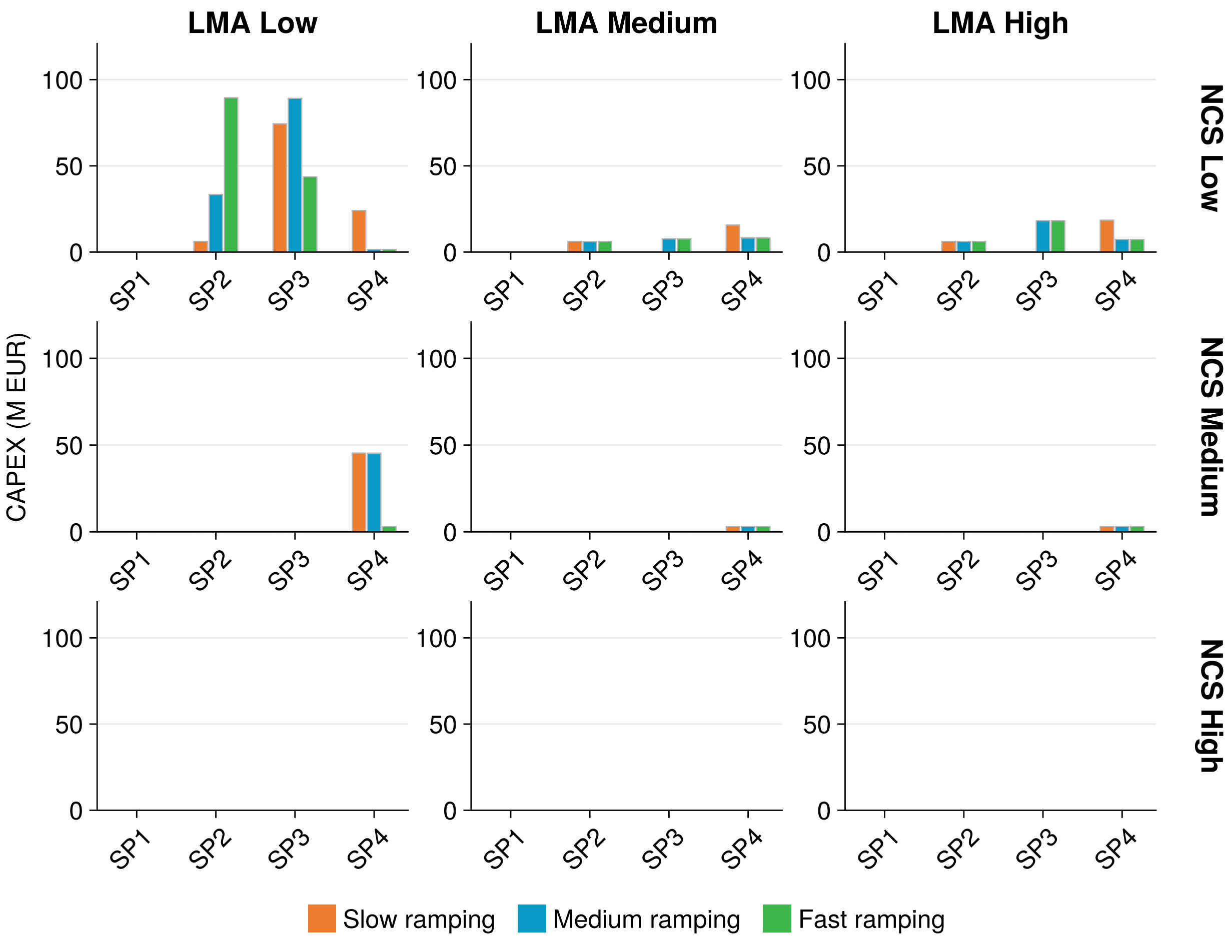

Figure 4.4 Staged investment in deblending capacity in millions of euros.
Horizontally LMA scenarios and for each the three ramping scenarios horizontally. Vertically gas production scenarios. 2% blending limit. (Note that there is no deblending investment in Dunkerque in any scenario.)

Deblending is not so much used to be able to sell pure hydrogen, but rather to reduce the hydrogen percentage in the natural gas deliveries to meet terminal requirements.

Figure 4.4 shows the staged investment in deblending capacity. Here the general trends are more or less mirroring the trends in dedicated pipeline and compressor capacity investment. As blending (deblending) is relatively cheaper, in scenarios where constructing a dedicated pipeline can be avoided or delayed, blending will happen. In the high NCS gas production scenarios, there is enough natural gas to blend in the hydrogen without having to deblend to meet terminal blending limits

Interestingly, we only see deblending in Dornum and not in Dunkerque. (Figure 4.6 shows a sensitivity for terminal blending limit 5% with cases where no gas flow to Dunkerque occurs.)
End-user prices in Dornum and Dunkerque are the same, however there are other differences that can drive this result. Possibly Dornum is preferred because the transport distances are shorter and supply there requires less compression. The possibly blended gas flows from EuroPipe I and EurePipe II are mixed before arriving in Dornum. This may make the PSA deblending costs per unit of hydrogen throughput lower in Dornum than in Dunkerque.

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4.10 Sensitivity analysis

Here we consider the effects of allowing a higher terminal blending limit. A lower limit increases the need for deblending or may incentivize construction of a dedicated hydrogen pipeline. A higher limit decreases the need for deblending and may disincentivize construction of a dedicated hydrogen pipeline. We find that allowing a 20% blending limit at the terminal results in a 13% higher objective function value compared to 1%.

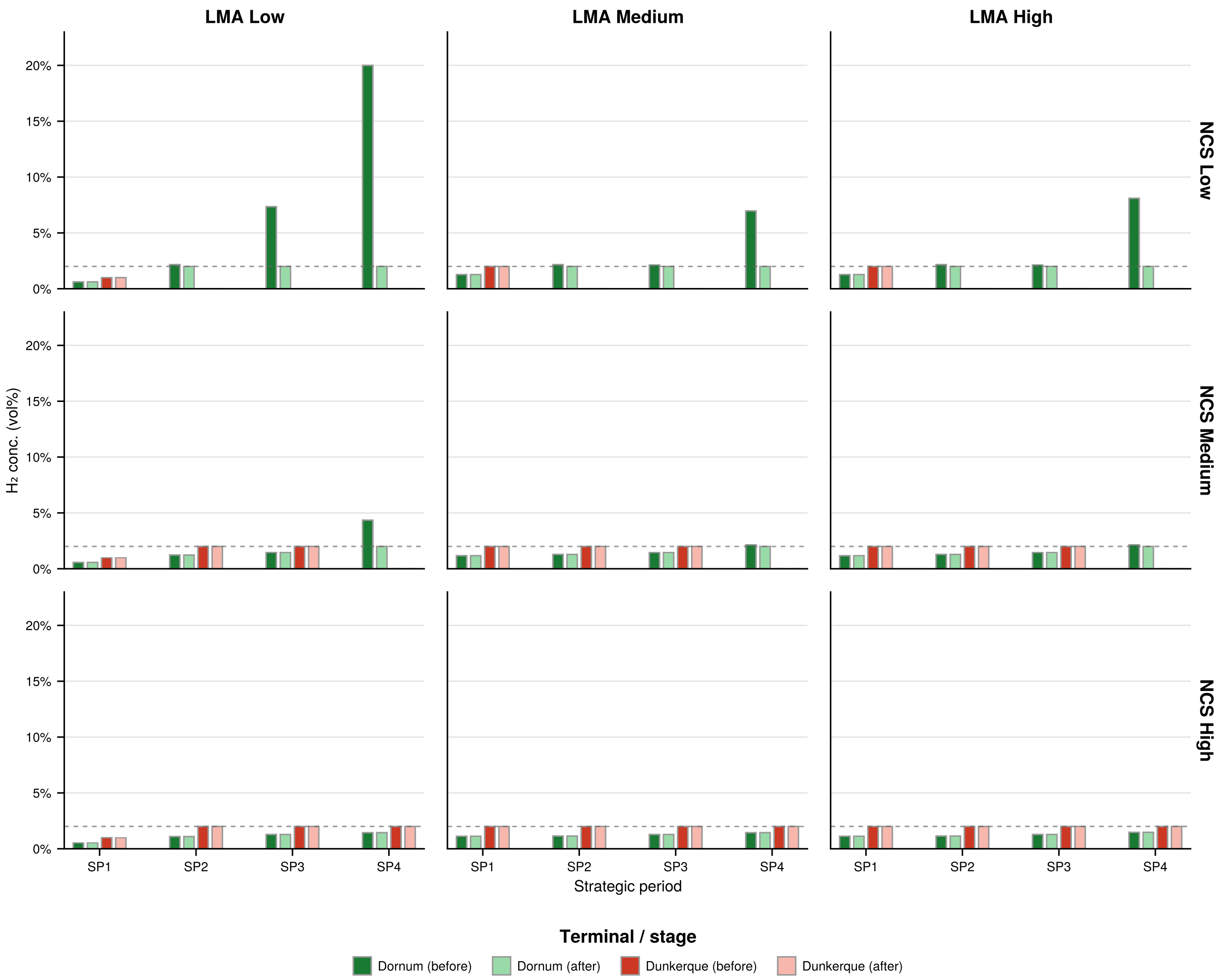

Figure 4.5: Hydrogen percentage at terminals before and after deblending (2% limit at terminal)

Figure 4.5 illustrates how the combination of hydrogen and gas production assumptions drive the need for deblending (considering a 2% blending limit at the terminals).

We see two types of solutions: low blending in the network, and no need for deblending, or higher than 2% blending in the network, all flows go to Dornum, and there is investment in deblending in Dornum.

Low hydrogen Low gas invests in a new 14 inch pipeline (ref Figure 4.2). Once that is full and its capacity cannot be further increased by additional compression capacity, the blending percentage in the network is increased to the highest allowed. We can also interpret this as: the combination of

The research leading to these results has received funding from Horizon Europe, the European Union's Framework Programme for Research and Innovation under grant agreement n° 101111888.

blending limit and pipeline capacity is optimized such that the total hydrogen volumes can be brought to market at minimum cost

Moving to the right in Figure 4.5 higher hydrogen volumes need to be transported, but as over the entire planning horizon it is beneficial to invest in a dedicated pipeline, the blending percentages in the network stay lower, especially in later stages.

Figure 4.6 illustrates the blending-deblending results for a 5% blending limit at the terminals. As in Figure 4.5 we see two types of solutions: low blending in the network, and no need for deblending, or higher than 5% blending in the network, all flows go to Dornum, and there is investment in deblending in Dornum.

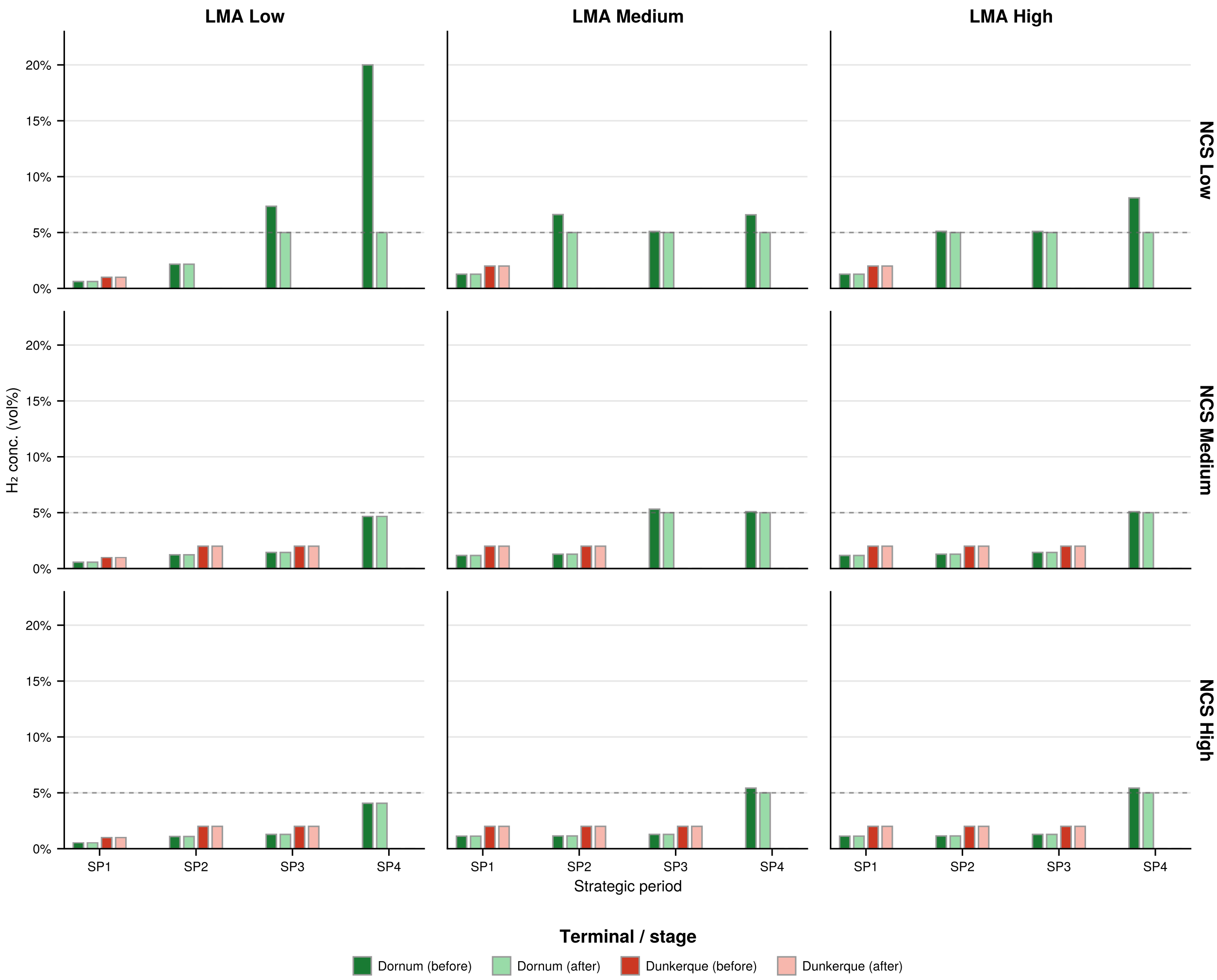

Figure 4.6: Hydrogen percentage at terminals before and after deblending (5% limit at terminal)

Figure 4.7 illustrates that repurposing can be beneficial when there is a lack of natural gas volumes to blend in hydrogen, there is a relatively rapid phase out of gas volume meaning that the opportunity cost due to lost gas revenues are low, and there is not enough hydrogen foreseen to warrant construction of a new pipeline. In other cases, new dedicated hydrogen pipeline construction and or deblending are preferred.

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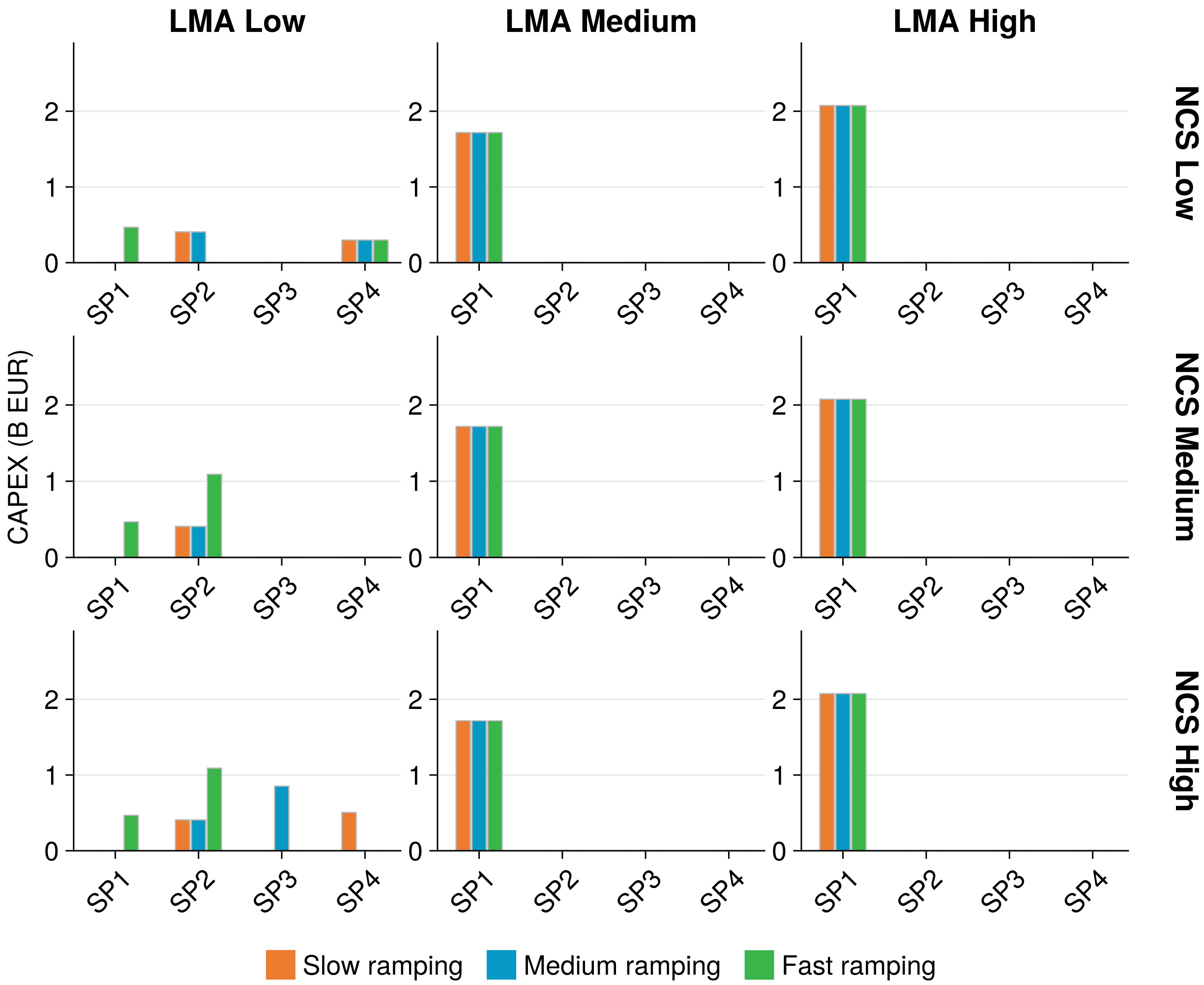

Figure 4.7 H_2 corridor staged investment for blending limit 1%

4.11 Performance of discretized model

To investigate how the discretisation of the model discussed in Section 3.5, we performed a validation run of some selected sensitivities and solved the same instances using both the full non-linear formulation and the discretised version of the same model instances. This test was performed for the combination of LMA and NCS scenarios, using the scenarios with 2% hydrogen limit at terminals and fast ramping.

The test showed that the objective function values are practically identical between the formulations, while the performance of the discretised version is 8-300 times faster, using the open-source SCIP solver for non-linear (MINLP) and the commercial FICO Xpress for the discretised formulation (MILP) with a time limit of one hour, see Table 4.9.

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Table 4.9 Runtime comparison between discretized (MILP) and non-linear (MINLP) formulations of the same problem instances. 2% hydrogen allowed and fast ramping

LMA	NCS	MILP (s)	MINLP (s)	Speeup (x)
Low	Low	266.7	3621.7	13.6
Low	Medium	6.1	49.1	8.0
Low	High	3.0	98.7	32.9
Medium	Low	17.5	3600.5	205.7
Medium	Medium	10.0	177.8	17.8
Medium	High	9.8	83.8	8.6
High	Low	9.3	2824.4	303.7
High	Medium	8.2	2099.3	256.0
High	High	5.9	243.4	41.3

The following chapter describes the second case study analysed in this subtask, Zaragoza/Enagás.

5 Case Study 2: Ebro Valley/Zaragoza Enagás

Over the past decades Spain has become one of largest Liquefied Natural Gas (LNG) importers in Europe. Regional networks have developed in the relative proximity of LNG regasification terminals, and there is a country-wide high pressure gas transport system.

Significant parts of inland Spain have hardly any residents and offer potential for onshore wind generation. At the same time, Spain has favourable conditions for solar PV. Electrolyzers powered by renewable solar and wind generation may become major hydrogen supply sources within the European Union.[8,9,10]

Enagás is a Spanish company specialized in the transmission, regasification, and (underground) storage of natural gas. The company is the main natural gas TSO in Spain as it is the owner and operator of more than 12,000 km of high-pressure gas pipelines. The company's gas network in Spain comprises of the high-pressure pipelines, 6 connections to neighbouring countries (France, Portugal, Algeria and Morocco), and 19 compressor stations.[11]

[8] https://h2medproject.com/

[9] https://www.enagas.es/en/energy-transition/hydrogen-network/h2med/

[10] https://ehb.eu/page/country-specific-developments#spain-enagas

[11] https://www.enagas.es/en/energy-transition/gas-network/gas-infrastructure/transmission-network/gas-pipelines/

The research leading to these results has received funding from Horizon Europe, the European Union's Framework Programme for Research and Innovation under grant agreement n° 101111888.

Figure 5.1: The high-pressure transmission network case from ENAGAS.

The network is located in the area of Zaragoza, North-East in Spain. Red lines indicate pipelines, blue circles compressor stations (EC 1-4) and the black circle the underground natural gas storage facility (AS).

For use in the case studies of the project, Enagás provided detailed date for a part of the transmission network, which is illustrated above in Figure 5.1. The network is in the area around Zaragoza, in the North-East part of Spain close to the border with France. More specifically the high-pressure pipeline concerns part of the Barcelona-Bilbao-Valencia (BBV) transmission line, which supplies the Aragon and La Rioja regions including consumers in the Serrablo area (Pyrenean foothills south of the Pyrenees) where there exits an underground natural gas storage facility.

The selected network consists of 17 pipe sections with a total length of 738 km, and it is operated with a nominal pressure of 72 bar. For a more detailed description of the network, please refer to deliverable D4.1 *Report describing the defined simulated test cases, realistic scale testcase(s), and available operational models including required data set and format*.

For the Zaragoza case study, we investigate the optimal strategy for transporting H_2 produced nearby local gas transmission and distribution grids. The main questions we try to answer in this case study:

- How should the regional network infrastructure be reinforced to accommodate anticipated hydrogen injection profiles?
- How much hydrogen buffer storage should be built to maintain acceptable level of hydrogen in the network over different representative periods covering both winter and summer seasons with variations in network operation.

- How much deblending capacity will be needed to keep the hydrogen percentage below the required 2% allowed for injection into the underground storage?

The case study models H_2 injection from three electrolysis facilities located at sites with renewable energy availability and investigates the optimal operation of H_2 injection into the gas distribution network while respecting blend limits at consumer delivery points and injection of natural gas from regasification plants in other parts of the network. The Serrablo underground gas storage (UGS) facility provides seasonal balancing capability. The model optimises operational decisions for several operational periods representing both winter and summer season operations.

5.1 Network Description

The regional network instance includes approximately 125 nodes and 130 pipeline links in the BBVcorridor and the Serrablo transmission network. This network is significantly larger than the Gassco network on the Norwegian NCS and presented a notable computational challenge for the EMX model due to a large number of pipeline segments and delivery points and the need to model bidirectional pipelines to accommodate the different gas transmission conditions depending on where natural gas is injected into the network. Solution time for model instances were significantly longer (several minutes up to hours) compared with the Gassco use case (seconds), and fewer sensitivities have been performed for this case study for this reason.

The network topology is characterized by a loop structure with supply options feeding into the network from several directions (somewhat but not entirely related to seasonality.) The main supply points considered in the further analyses are from the South-East and from the North-West. In addition, the network features a large seasonal underground gas storage in the North. Along the main transmission lines are multiple demand clusters, necessitating the subdivision of the main pipeline corridors into multiple pipelines segments to represent pressure drops.

5.2 Assumptions

This section briefly describes some of the main model and data assumptions for the Zaragoza case study.

5.2.1 Time Structure

The model optimises operational decisions over a range of four operational periods representing different times of day for both winter and summer season. During each season, injection of gas from the South-East (Barcelona region, which has an LNG regasification terminal) and from the North-West (representing injection in e.g. Bilbao region, which has an LNG regasification terminal and/or transmission from France) as well as a period without any injection from outside the case study network. Concerning time periods, we consider:

- 1 strategic period (SP1) representing one planning year
- 6 representative seasonal periods, three for each season (summer/winter) with four operational periods to represent a day:
  - RP1-3 (summer, 4 time steps of 6h)
  - RP4-6 (winter, 4 time steps of 6h)

Each RP is scaled to represent 2 months of annual operation.

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5.2.2 Electrolyser assumptions

Table 5.1 presents the characteristics of the electrolyzers considered in the case study as well as the locations considered for placing them.

Table 5.1: Electrolysers

Name	Node	Location	Coordinates	Capacity (Nm^3/h)	Rated Power (MW)
El3	74	SE Zaragoza	41.53°N, 0.68°W	40,000	200
El2	75	Gallur	41.78°N, 1.27°W	20,000	100
El1	77	Serrablo	42.22°N, 0.53°W	6,000	30

5.3 Hydrogen Storage Tanks

For Hydrogen Storage Tanks we consider a data sheet from Danish Energy Agency [10]. For 2020, the value listed is 0.00319 [MEUR/MWh], which equals 3.19 MEUR/GWh. We have assumed a unit CAPEX of 31.90 $MEUR/MSm^3$. We have not applied the cost reductions assumed by DEA 2025 for future years.

The OPEX of H_2 storage is mainly related to energy consumption for compression for injection. Service gas in natural gas storages is typically a low single digit percentage loss of the injected gas. In this analysis we have not included OPEX for hydrogen storage.

5.3.1 Gas Pricing and Penalties

Table 5.2 provides monetary parameter values used in the objective function of the optimization model. The values are aligned with TTF market prices for natural gas and low production costs for hydrogen based on abundant renewable energy. To facilitate model feasibility, we allow the model to not supply to all demand but rather penalize supply deficits to consumers heavily.[12] This is simplified compared with the energy pricing in the Norwegian case study, but sufficient for this analysis focusing on gas volumes.

Table 5.2: Gas pricing and penalty assumptions Zaragoza case [EUR/Nm^3]

Component	Summer (RP1)	Winter (RP2)	Notes
CH_4 supply (all nodes)	0.25	0.40	TTF-based, 2026 forward curve[13]
Consumer deficit penalty	200	200	Applies at all consumer sinks
H_2 production cost (El3)	0.05	0.05	Low-cost renewables assumed

5.4 Implementation details

This model instance was solved using FICO Xpress as the MILP solver with a time limit of 10 hours and was solved with a remaining optimality gap of ca 1%.

[12] A high penalty will enforce meeting all demand if that is feasible, but if input parameter values would lead to an infeasible problem, the optimization will find a good approximate solution, but also indicate where the issues are, so that assumptions may be adjusted.

[13] TTF prices in €/MWh. Considering HHV 11 kWh/m3, divide TTF price by 91 to get €/m^3 (e.g., €50/MWh ~ 0.55 €/m^3)

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5.5 Results and analysis

To investigate the role of buffer storages versus deblending facilities in the network, we consider a case where hydrogen production varies during the day. This is consistent with the technical characteristics of PEM electrolysers which are flexible although fluctuating operation but may not be an economically sound strategy due to increased wear on the electrolyser and lower utilization of the installed capacity.

Nevertheless, we simulate variations in production in a stylized case where the producer of hydrogen exploits differences in electricity prices and having a buffer storage enables the hydrogen producer to shift injection into the network from periods with low electricity prices to periods with high electricity prices while benefiting from the production during periods with low electricity prices. The benefits of this arbitrage must be larger than the cost of the storage for this strategy to be profitable.

We represent the seasonal variations and differences in network operations due to injection from different locations by a time structure with six representative periods, three for each season (summer/winter). Each representative period is divided into four operational periods, subject to different prices and RES availability. Each representative period within each season has a different injection scheme for natural gas, one with injection from the South-East (Barcelona region), one with injection from the Nort-West (Bilbao region or interconnection from France) and one without a specific injection from a regasification plant. The different injection schemes give different network operations, and different potential for hydrogen injection to stay below the imposed maximum constraints of 5% hydrogen for delivery to customers[14] and 2% for injection into the underground storage.

The model suggests investment in buffer storages, with a larger capacity in the node that is connected to the larger interconnection that has higher capacity to absorb H_2, electrolyser El1. The utilisation and investment in the other electrolysers are 10-100 times smaller, as they have less potential to inject hydrogen while keeping the blend limit of 5% As we do not consider any economies of scale in investment costs and operation costs, this must be the optimal location for hydrogen injection of the three options available.

The production and injection are much lower than the assumed installed capacity for the electrolyzer. This leads to some notable behaviour from the optimization, as it chooses to let all production take place in the operational time periods with the lowest power price each day. This production pattern is an artifact of not considering CAPEX for the electrolyser in the analysis, and the high level of installed electrolyser capacity combined with buffer storage capacity compared to the possible admixing levels. However, it does lead to large variations in hydrogen production, thereby effectively stressing the system to simulate very different operational situations.

[14] Spanish gas regulations allow to supply natural gas with up to 5% H_2 to non-sensitive users

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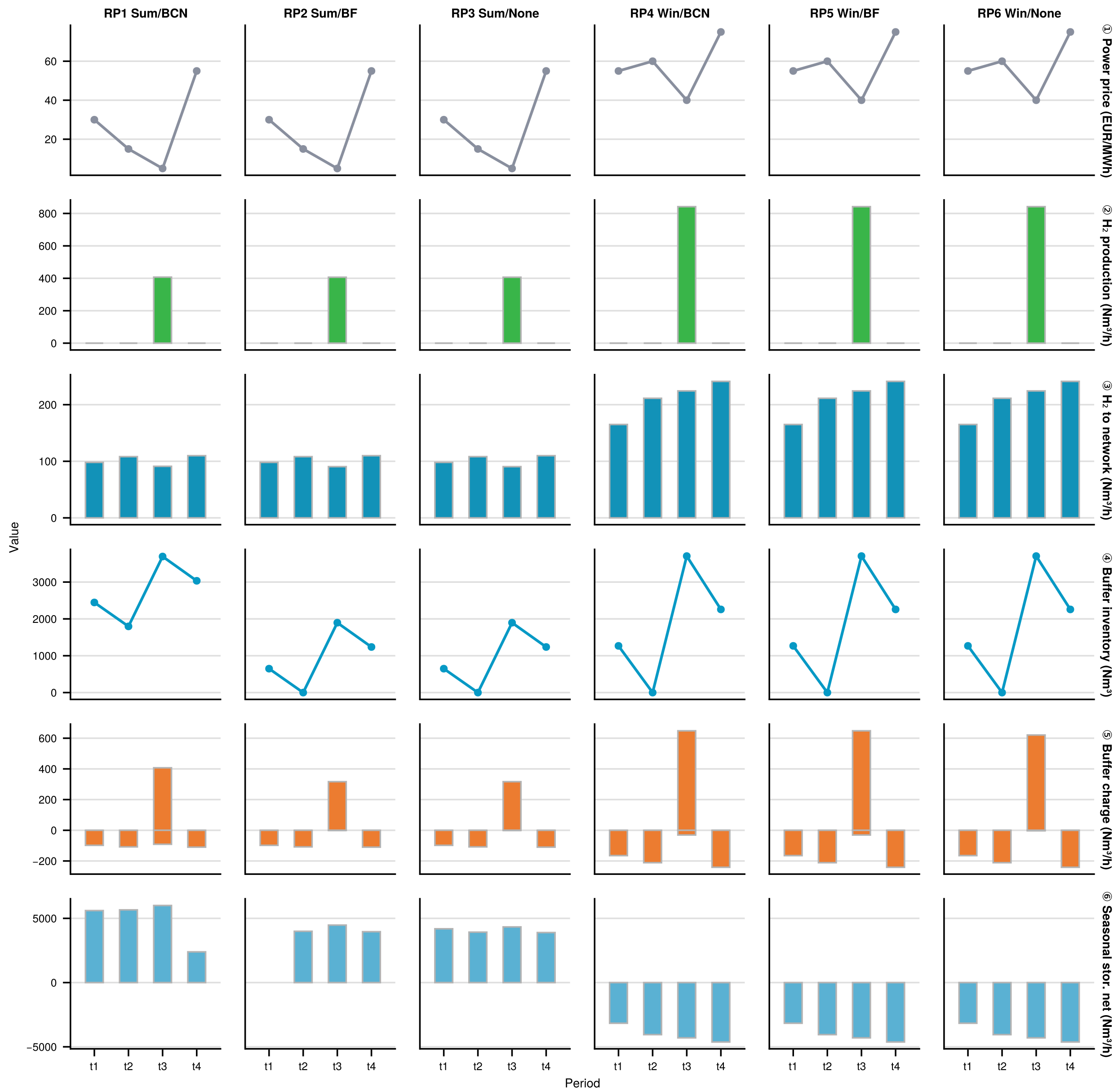

Figure 5.2: Operational results Zaragoza case for each Representative Period (RP).
Top row shows power prices, second row hydrogen production, third row injection into network, fourth row storage status. Lowest two rows show charging (row five) and discharging (row six) of buffer storage and seasonal storage. BCN / BF / none consider the time periods high injection into the considered network from the Barcelona region, Bilbao/France and no large external injections, respectively.

Figure 5.2 summarizes the results for the Zaragoza case. It shows some key input parameters and results from the operational periods to illustrate the model results. Each representative period is shown as a column of subplot, with the three summer periods to the left, and the three winter periods on the right. Each subplot shows the four operational periods used to represent the operations in this representative period. The top row shows the assumed power prices, emulating a diurnal pattern with lower prices in the afternoon and a higher price peak in the evening. Note that the model considers the time structure in a cyclical fashion, so model results may indicate that storage extraction happens before storage injection.

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The lowest three rows show how the buffer storage successfully evens out hydrogen injection to maximize injection according to available natural gas transport volumes for admixing, while satisfying demand and quality constraints for all time periods. The model seeks to minimize the production cost, and since the hydrogen volumes that can be admixed production that are so low compared with installed capacity, all production is concentrated in the period with lowest prices (t3) in all representative seasonal periods. This is not in isolation a realistic result, as the CAPEX of electrolysers and other assets typically require higher uptime to justify the investment. Similarly, not bound by any capacity limitations, production is higher in winter, which would be surprising given the generally higher power prices and thus higher production cost of hydrogen in winter. It is in this case however mainly a result of strong economic incentives imposed to deliver hydrogen into the network, and the larger network flows of natural gas in winter allowing higher injection.

The limitation on hydrogen admixing is due to the constraints on maximum hydrogen percentage reaching customers (5%). However, the UGS 2% hydrogen constraint does not restrict hydrogen injection because the flow patterns and location of hydrogen injection means no hydrogen reaches the UGS. The available natural gas for diluting the hydrogen is limiting the amount of hydrogen that can be injected into the network. In turn, the electrolysers are only operating at a few percent of installed capacity, which implies that they must have other outlets for hydrogen to operate at the design scale. Such other outlets could for instance be use in local industrial clusters or transport by dedicated transport infrastructure for hydrogen. Investigating this further is outside the scope of this SHIMMER case study.

As can be seen in the third row in light blue bars, the injection into the network is successfully smoothened out by the use of the buffer storage, for which the storage level and injection and extraction volumes in each operational period can be seen in the fourth and fifth rows. Finally, the lowest row shows the injection and extraction volumes from the underground gas storage. While the hydrogen buffer storage is used to balance out within the day and can be used for diurnal variations, the seasonal storage is required to balance out over a full year (as we do not allow net extraction or injection over a year).

In short, while several hydrogen injection points were evaluated simultaneously in the analysis, the electrolyser that can inject into a large transmission pipeline with larger flow is the main producer/injecter in the solution suggested by the optimizer. This follows naturally from the blend limit being the dimensioning constraint. While buffer storages can be useful to smoothen the injection to best exploit available natural gas for injection, the available natural gas transport volumes are the limiting factor for hydrogen use in H_2 admixing, and other uses or transport modes would be necessary to accommodate supplying larger volumes of hydrogen.

The chapter hereafter, Chapter 6, aims to discuss the common findings for the two case studies, and provide generalizable insights.

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6 Discussion

In this chapter we aim to lift some generalizable insights from the case studies presented in Chapters 4 and 5. A main observation is that the use of pipelines for natural gas transport strongly influences how and when admixing can be used successfully for hydrogen transport. This is true both when volumes of natural gas transported are large and repurposing to hydrogen may have a large opportunity cost, but also when volumes of natural gas are low, as that limits the amount of hydrogen that can be injected into the network before the limit on the allowed hydrogen percentage is met. Thus, there is a window of opportunity for hydrogen mixing when there is enough natural gas to blend with so that the hydrogen share in the natural gas follow can stay below market or regulatory constraints. How much hydrogen can be injected depends on technical network specifics and what the pipeline materials can support in terms of admixing and how the network is operated. These characteristics must be investigated for each specific network where admixing is considered before drawing conclusions. Especially if such technical network and operating characteristics would impose further restrictions on feasible solutions of the optimization model, not considering them explicitly may lead to wrong conclusions based on the outcomes of the decision support model.

Looking at the results from the Gassco case study together in Figure 6.1, we see that blending is preferred in cases where less than 5 MSm3/d of hydrogen needs to be transported, and the overall potential of blending is around 5%. For larger volumes, the model generally selects building new dedicated transport capacity for hydrogen. While the results concerning blending will be sensitive to our assumptions on the cost of deblending, it is interesting to note that only with very small hydrogen volumes, less than 3 MSm3/d and high volume of natural gas (100 MSm3/d) is the pure blending strategy chosen. We highlight the slow ramping here because the results are more diverse, the tendency to build new pipelines is even stronger for the medium and fast ramping scenarios.

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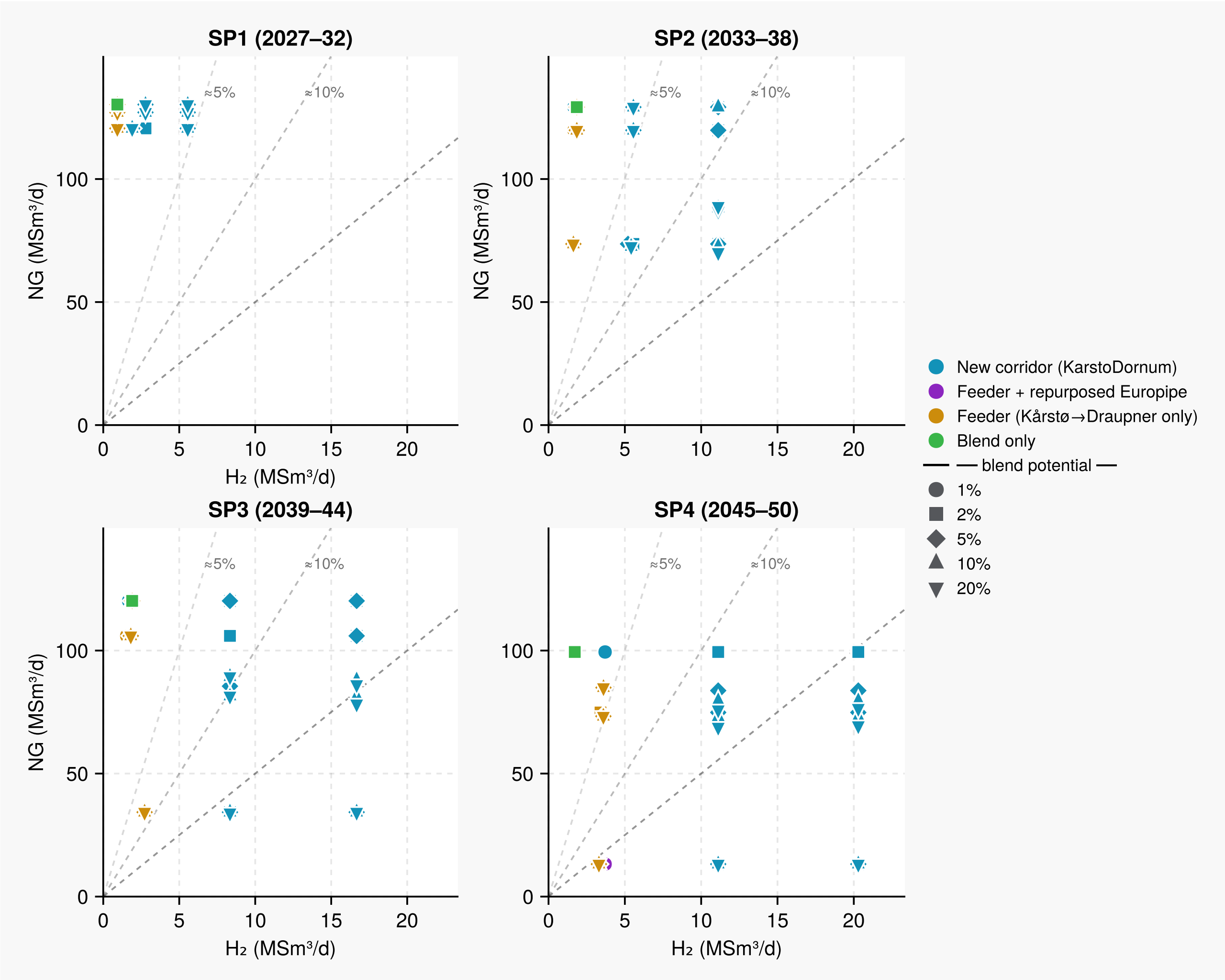

Figure 6.1 Strategy by volumes transported of hydrogen and natural gas (slow ramping). The dashed lines shows "blending potential" if all hydrogen were blended with all natural gas for reference.

Building new dedicated hydrogen pipelines may be needed to transport large volumes of hydrogen when admixing capacity is not sufficient, as could be seen both in the Gassco case and the Enagás case. Consolidating natural gas flows may be an option to have high enough gas volumes that allow admixing, but this requires that the network topology allows consolidating flows and it may come at the expense of giving up gas delivery to some points/terminals.

The opportunity cost of not delivering gas may be high. Over the past years the reliance of the European Union on Liquefied Natural Gas imports has increased, to substitute for disrupted pipeline imports from Russia. European natural gas prices have been substantially higher, and Norway is considered a very reliable supply source. Even in a scenario where the EU would phase out natural gas consumption relatively rapidly towards 2050, it is quite likely that imports from Norway will continue for several more decades at significant levels.

For pipelines with hourly capacities of some millions of cubic meters of natural gas, at limit of 2% hydrogen means that some tens of thousands of cubic meters of hydrogen can be admixed per hour. Hydrogen has a volumetric energy density, at 2.8 kWh/cubic meter (LHV). The output of large-scale

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electrolysers may be above what may be admixable.[15] Buffer storages can be used to smoothen out variations in hydrogen production levels from electrolyzers fuelled by intermittent renewable sources and thereby allow electrolysers with larger (peak) capacities. However, in our case studies, the ability to increase injection is limited by the availability of natural gas to mix with, which turns out to be the more limiting restriction. Buffer storages do allow shifting injection between periods and can be important to maximise the use of the available natural gas for admixing over time by shifting hydrogen injection to periods with available natural gas for dilution or higher "absorption capacity".

The state of materials needs to be assessed to know the maximum allowed H_2 admixing shares (see [11]). The amount of hydrogen that is allowed for blending influences how much value can be realized from H_2 admixing, and for moderate volumes admixing can be the most cost-effective option to bring hydrogen to the market. In both case studies we see how the binding constraint is the allowed mixed percentage and solutions are effectively limited by the maximum allowed hydrogen percentage. Depending on the network configuration and injection points, building pipelines around bottlenecks can be beneficial or consolidating flows can save costs when gas flows are low. Only when hydrogen volumes scale to high enough levels, dedicated pipelines to demand terminals become profitable. In such cases the ramping up speed of hydrogen production compared to the phasing out speed of natural gas will drive whether repurposing can be relevant, or whether new construction is the best solution.

In some cases, the fact that injection is limited by the availability of natural gas to blend with can give somewhat paradoxical result in the optimization model with higher production and injection in winter due to higher available gas volumes in the pipelines. If wind would be the main power supply for electrolysers, winter hydrogen production would typically be higher than summer hydrogen production. In contrast, if electrolysers would be solar or hydro-reservoir powered, the lower electricity prices in summer might make hydrogen production in summer more attractive. In any case one needs to consider the fact that the availability of natural gas for blending is important for the potential of hydrogen admixing.

We could see clearly from the scenario analyses for the Gassco case how cost and price assumptions to a large degree drive the results: Natural gas prices are important, in particular due to the opportunity cost of not transporting natural gas due to repurposing of pipelines to hydrogen transport. The costs, volumes and profitability of hydrogen is what mainly drives the investments in hydrogen infrastructure in our scenarios, and values for these are associated with large uncertainty (which is the reason that we have not defined a reference scenario but rather considered a large span of scenarios.) Which infrastructure solutions are optimal varies with the assumptions, and the development over time is important as there are some clear opportunities to do staged development such that some capacity expansion decisions may be delayed until more information is available. A clear example of this is building pipelines but delaying building the full compression and/or deblending capacity until hydrogen production and transport needs increase. Pipeline investments benefit from economies of scale, much more so in pipelines themselves than in compressor capacity. Therefore, decoupling the construction of a larger pipeline from eventually needed compressor capacity allows benefiting from economies of scale and construction flexibility to minimize total cost

[15] 2% of one million m^3 = 20,000 m^3. 2.8 MJ/m^3 x 20,000 m^3/hour = 56 MWh/h x 8760 hours = 0.491 TWh per year. Also, 56 MWh/h would be the production of an electrolyzer with an input capacity of 80 MWh @ 70% efficiency.

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over the planning horizon. For larger hydrogen volumes dedicated pipelines were preferred in the Gassco case. Especially in scenarios with slow ramping to high hydrogen volumes the delayed compression construction saves significant costs while allowing to benefit from the delivery of high pure hydrogen volumes to markets.

Deblending is a strategy that can be used to supply pure hydrogen to the market and to avoid too high hydrogen concentration at specific delivery points. The cost data estimates for deblending are very uncertain, both CAPEX and OPEX. The benefit of deblending will in practice also depend on other cost and transport patterns and network blending limits, and the premium of pure hydrogen compared to admixed natural gas.

Energy systems models such as EnergyModelsGasNetworks (EMGN) provide a framework for exploring alternative options for network development, and this study illustrates the potential of combining capacity expansion modelling with insights and assumptions from “more physically accurate” modelling. In contrast to simulation models, in EMGN the OPEX of gas transport depends on the compressor pressure regime and more compression implies higher cost.

Additionally, EMGN approximate the change of capacity dependent on the simulated operation of the network and admixed hydrogen percentages. Note that while this marks a big improvement from assuming fixed cost and capacities, also our model functionality for compression cost is an approximation.

The functionality enhancements in EMGN have led to additional nonconvex, nonlinear mathematical expressions as well as integer variables. Therefore, the computational expenses as a consequence of the model strengths of EMGN mean that large-scale network instances cases with many pipeline segments like the Enagás study for the Zaragoza area can be challenging to solve. Solution times of several hours makes it more demanding to perform large sensitivity analysis on hundreds of scenario variants as was performed for the Gassco case study with solution times typically less than a minute for the discretized formulation.

EnergyModelsX with the EMGN extension offers the tools to adjust the physical detail and accuracy against computational tractability by adjusting the granularity of the time resolution, whether to use the nonlinear formulation or the discretization (which again can be tuned with adjustable granularity) and the number of approximation planes for the capacity constraints (PWA).

To increase the accuracy of results, each location and dimensioning can be studied with more physical detail using simulation tools such as the ones developed in the project (See deliverable D4.6 for an example.)

6.1 Policy considerations

Politicians have stated large ambitions about EU production and demand level targets for hydrogen, but infrastructure build-out and demand are lagging and lacking. At present, the large uncertainty in the development of hydrogen markets and component costs makes it challenging for suppliers and consumers to commit and invest in scaling up hydrogen, which is hampering infrastructure build-out. A significant level of energy independence requires European domestic hydrogen production and transport networks. If hydrogen is to contribute to reaching climate targets, there needs to be a clear policy framework with adequate incentives and sufficient coordination so that suppliers can scale up

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rapidly knowing there will be a market, and demand sectors can invest in hydrogen equipment knowing there will be supply. Lacking an adequate playing field is hampering hydrogen initiatives and only makes it more expensive to ramp up hydrogen supply; something that we cannot afford in this phase of the energy transition. A clear and adequate playing field will facilitate a hydrogen ramp up and allow making better trade-offs and using synergies to reduce the costs of the energy transition.

The following chapter wraps up the report by presenting main findings, concluding remarks and recommendations.

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7 Conclusions and recommendations

In Chapter 4 we posed two research questions:

- What mixing strategies are recommended for the case of exporting hydrogen from renewable production via pipelines from Norway?
- What infrastructure would be needed to support these mixing strategies, and which capacities?

In Chapter 5 we posed three research questions:

- How should the regional network infrastructure be reinforced to accommodate anticipated hydrogen injection profiles?
- How much hydrogen buffer storage should be built to maintain acceptable quality in the network over different representative periods covering both winter and summer seasons with variations in network operation.
- How much deblending capacity will be needed to keep the hydrogen percentage below the required 2% allowed for injection into the underground storage?

In this concluding chapter we relate insights from our analyses to these questions.

Hydrogen admixing can provide a cost-effective option for transporting certain volumes of hydrogen by reducing the need for costly infrastructure investments.

The natural gas volumes in a network can increase and limit the potential of hydrogen admixing. On the one hand, the opportunity cost of natural gas transmission and export can be a significant barrier against repurposing infrastructure to pure hydrogen transport, making admixing the only option to bring hydrogen to the markets. On the other hand, when the volumes of natural gas are too low, they may not offer enough volume to dilute H_2 to the required operating levels. Network limits on blending imply that the amount of hydrogen that can be injected will be limited by the amount of natural gas flowing in pipelines. Typically, gas supply and flows are higher in winter than in summer. This may give rise to issues if the relative capacity to absorb hydrogen in summer and winter would not match a structural seasonal difference in electrolyzer activity and hydrogen production.

Consolidating gas flows can be ways to accommodate the network to support H_2 admixing. Traditionally, the combination of supply contracts and spot prices have been driving where Norwegian natural gas exports were destined for. If the relative value of hydrogen becomes high enough, or if admixing would be imposed by policy measures, the situation may occur that admixing needs become a major factor in routing of (natural) gas flows through the network. If such rerouting is not market driven, it may impose a relatively large cost to the TSO who is operating the compressors, but also to gas suppliers at the Norwegian Continental Shelf if they may have less leeway to arbitrage price difference in various EU markets and thereby sacrifice opportunities for higher profits.

Investing in new dedicated pipelines for hydrogen is an expensive option, which is only warranted if hydrogen volumes become high enough, and repurposing is too expensive or would lead to high opportunity costs due to lost natural gas revenues.

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Buffer storages can play an important role in balancing varying hydrogen injection from renewable sources over time by decoupling injection into the network from production. Generally, this can increase the injection potential, although the case studies in SHIMMER indicate that the admixing potential would still be limited by natural gas volumes. Specific advice on infrastructure dimensioning should not be taken from our analyses, but need more detailed studies for each location, however.

If the properties of infrastructure and asset materials and components allow, increasing the allowed amount of hydrogen in natural gas will improve the potential for added value by admixing, as admixing significantly decreases investment costs. However, due to the potential damage from hydrogen a feasibility assessment is needed before any repurposing can be considered.

To allow pure hydrogen sales after admixing and to overcome differences in blending limit requirements deblending of admixed gas volumes can provide an alternative to transport hydrogen in dedicated pipelines. It would facilitate operation in a separate market for hydrogen with premium prices and can also be used to increase the amount of hydrogen transported in the network even though some terminals may only support lower percentages of hydrogen than the network allows. However, the business case of deblending hinges strongly on the cost assumptions. As the technology exists, but there is hardly any experience with use on the scales needed to deblend volumes in the million m^3 per hour level, more study is needed.

Beware that conclusions are sensitive to assumed costs and should be studied with carefully adjusted estimates for each location, just as how much blending will be allowed in the network will need to be assessed carefully as mentioned in D3.1 [11]. The main conclusions about economics of scale for pipelines, opportunity cost of existing natural gas transport and the natural gas flow volumes limiting hydrogen admixing potential are intended to be generalizable and robust, however.

7.1 Recommendations

Expected natural gas volumes in networks where hydrogen admixing is considered must be evaluated closely, as both too low volumes, and too high volumes present a barrier against implementation of admixing strategies.

Buffer storages can be an important means to achieve more even injection volumes and achieve maximum injection from intermittent production from renewable sources, but the volumes available for dilution of hydrogen in natural gas are still limiting the amount of hydrogen that may be injected.

If a higher percentage of hydrogen admixing can be allowed, this would increase the value of this lower cost solution for use of hydrogen, but for large scale development of hydrogen production, dedicated transport corridors will be required as the volumes will still be limited by the volumes of natural gas.

Clear expectations on development of hydrogen markets are important for investors to plan, and as we can see that the solutions on how to best develop infrastructure depend so much on how these markets develop, means to reduce uncertainty in future hydrogen markets will increase chances of successful implementation of the needed new infrastructure.

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