Re-Stream

Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe

DNV

CARBON LIMITS

This report was prepared for:

Date of publication: October 2021

List of participating operators to the study *(by alphabetical order)*

Onshore gas pipeline

1. AB Amber Grid
2. bayernets GmbH
3. Conexus Baltic Grid
4. DESFA S.A.
5. Enagás Transporte, S.A.U.
6. Energinet
7. eustream, a.s.
8. FGSZ Natural Gas Transmission Plc.
9. Fluxys Belgium S.A.
10. Fluxys Tenp GmbH
11. Gas Connect Austria GmbH
12. Gas Transmission Operator GAZ-SYSTEM S.A.
13. GASCADE Gastransport GmbH
14. Gasgrid Finland Oy
15. Gastransport Nord GmbH
16. Gasunie Deutschland Transport Services GmbH
17. Gasunie Transport Services B.V.
18. GRTgaz
19. GRTgaz Deutschland GmbH
20. Hellenic Gas Transmision System Operator S.A.
21. National Grid Gas plc
22. NEL Gastransport GmbH
23. NET4GAS, s.r.o.
24. Nowega GmbH
25. Ontras Gastransport GmbH
26. Open Grid Europe GmbH
27. REN - Gasodutos, S.A.
28. Snam S.p.A.
29. TAG GmbH
30. TERÉGA
31. terranets bw GmbH
32. Thyssengas GmbH

Onshore oil pipelines

1. BPA - British Pipeline Agency Ltd
2. CLC - Companhia Logística de Combustíveis, s.a
3. Dow Olefinverbund GmbH
4. Raffinerie Heide
5. JANAF Plc.
6. MERO ČR, a. s.
7. MOL Plc.
8. MVL - Die Mineralölverbundleitung GmbH Schwedt
9. Q8
10. Nord-West Ölleitung GmbH
11. N.V. Rotterdam Rijn Pijpleiding Maatschappij
12. RMR pipeline
13. Trapil - "Société des Transports Pétroliers par Pipeline"
14. Vermilion
15. Ineos FPS Ltd
16. Exolum
17. Danish Oil Pipe A/S
18. S.F.D.M

Offshore oil and gas pipeline

1. Aker BP ASA
2. CNOOC
3. CNR
4. ConocoPhillips Skandinavia AS
5. EnQuest Heather Ltd
6. Equinor Energy AS
7. Gassco AS
8. Ineos FPS Ltd
9. Ineos UK Sns Ltd
10. Neptune Energy
11. Repsol Sinopec
12. Shell
13. TAQA
14. TotalEnergies
15. Tullow

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Executive Summary

In the European Green Deal, the EU has set itself the ambitious target of achieving climate neutrality by 2050, with an intermediate target of reducing net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels.[1] The ambition of the EU increases the necessity of decarbonizing the industry, energy and transportation in Europe. Carbon Capture and Storage (CCS) and carbon-free energy carriers based on hydrogen are technologies which could significantly contribute to achieving the EU goals. Both CCS and large-scale hydrogen usage require transportation infrastructure. Reusing existing oil and gas infrastructure can lead to more cost-efficient deployment of CCS and hydrogen technologies and limit the costs of achieving EUs climate ambitions. The aim of the Re-Stream study is to provide fact-based elements to this statement and to identify relevant infrastructure and define what technical adaptations and investments would be required to unlock its potential for reuse for both CO_2 and 100% H_2.

Note that for smaller H_2 production and for existing gas pipelines, there is also a potential for blending of H_2 in the natural gas network in the early phase of the H_2 economy development. This is however not the focus of this study and is only briefly discussed in section 3.3.

65 pipeline operators participated in the Re-Stream study, providing data that could be analysed within the Re-Stream project for approximately 58,000 km of pipelines[2] (+24,200 km assessed by operators themselves as suitable for H_2 reuse) representing half of the total offshore pipeline length and approximately 30% of the onshore oil and gas pipelines.

Initial technical screening

An initial technical screening was undertaken considering the data provided by the pipeline operators. This analysis does not replace a full pipeline requalification process that would require way more inputs for each pipeline.

The criteria used for this initial screening are the material of construction and pipeline design characteristics (e.g. for CO_2, to check the resistance against running ductile fracture), the internal pipeline condition, safety matters, age and transport capacity. For calculations, design pressures have been adapted according to standards and flow requirements.

Other parameters such as, among others, the chemical composition, the heat treatments of the material, the welding procedure specification, the way a pipeline has been operated over the years are also factors that play an important role in the possibility for reuse of a pipeline. However, these parameters could not be considered at screening level.

Of the approximately 58,000 km pipelines assessed in this project (around 41,700 km onshore + 16,300 offshore)[3] for which data were received, the initial screening showed that technically:

[1] https://ec.europa.eu/commission/presscorner/detail/en/ip_21_1828
[2] Several operators have been / are assessing internally the reusability of their pipelines for H_2 and CO_2. Results from the Re-stream study should not prevail on operators' results considering the operators have access to more detailed data than the Re-stream team.
[3] 28,800 km of onshore gas pipelines / 12,900 km of crude/product onshore pipelines / 16,300 km offshore pipelines of which 13,000 km of gas pipelines

FOR CO_2

- There are no showstoppers identified for transporting CO_2 in the gaseous phase in the existing onshore and offshore pipelines.
- CO_2 transport in dense phase is possible in more than half of the offshore pipelines considering the current state of knowledge/standards. An additional 40% of the offshore length would require more testing, analyses and/or update of standards to be reusable.
- A very small portion of the onshore pipelines would be reusable for CO_2 transport in dense phase considering the current state of knowledge/standards. Approximately one quarter of the onshore length could be reusable provided positive results from more detailed analyses and/or tests.

FOR H_2

- Most of the offshore pipelines can be reused for H_2.
- Onshore, close to 70% of the pipeline total length can be reused considering the current state of knowledge/standards. The remaining length of the pipelines is promising for reuse but would require more testing and/or update of standards to be reusable. None of the pipelines analysed can be categorically excluded from reuse as of today.

It is noteworthy that for the pipelines assessed to be reusable considering the current state of knowledge/standards, pipeline requalification processes should still be undertaken, and testing might be needed. Indeed, as mentioned earlier some criteria could not be considered for this initial screening. Running ductile fracture requirements for dense phase CO_2 pipelines, fatigue crack growth for H_2 service, detailed integrity status of the pipeline and timing (date of availability of the pipeline for other use) are some of the critical factors to be evaluated as a first step of the pipeline requalification process.

Initial business opportunity review

The locations of sources (CO_2 emitters / H_2 storage / H_2 producers) and sinks (CO_2 storage locations / H_2 storage / H_2 consumers) were identified and a minimum pipeline length for business opportunities was calculated. There are some clear opportunities:

FOR CO_2

- A minimum of around 70% of the existing offshore pipeline length is relevant for CO_2 transport as many of the long pipelines are linking harbours to CO_2 storage locations.
- Regarding onshore pipelines, a minimum of 20% of the pipeline length shows some business opportunities linking sources to sinks (harbours or onshore storage sites). It is very likely that this proportion would grow significantly if the automatic approach undertaken in the study would have allowed for only part of the pipelines to be reused or for pipeline connections to be better considered.

FOR H_2

- A SMR/ATR production scenario gives a higher degree of obvious business opportunities compared to an electrolysis production one as SMR/ATR production locations are linked to the current gas infrastructure.
- Depending on the demand/production locational assumptions, the minimum reusable offshore pipeline length for hydrogen is between 2% and 25%.
- With regards to onshore, based on the demand/production locational assumptions taken in this study, the minimum reusable pipeline length for hydrogen is 20% to 30%. As for CO_2, it is very likely that this proportion would grow significantly if the automatic approach undertaken in the study would have allowed for only part of the pipelines to be reused or if pipeline connections, the

security of supply and the benefits of an interconnected market had been considered[4]. According to the operators, the EU network is so well meshed that current infrastructures are likely to be enough to connect production with demand with only the last miles that would need to be added.

Case study results

For six selected cases representing various scenarios of reuse (H_2 / CO_2 gas / CO_2 dense - onshore / offshore pipelines), no technical showstoppers were found at this stage. The economic assessment of those cases confirmed the strong potential for cost reduction involving reuse of pipelines compared to their new build options. For both CO_2 and H_2 transport, 53% to 82% of cost reduction can be achieved with around 2 MEUR/km cost reduction for offshore cases and 1 MEUR/km for onshore cases. Those cost reductions are of particular importance in the initial phases of development of CCS and hydrogen infrastructure.

What's next?

A list of technical challenges for pipeline reuse, including some criteria that cannot be covered at screening stages, are listed and discussed in chapter 7. Those challenges are classified in 4 main categories: Regulatory, Integrity, Safety, Operability. Mitigation actions are identified for each of the challenges.

The objective of this assessment was to estimate an overall reuse potential at EU level of the existing infrastructure and, as such, this assessment does not prevent the operators to go through a full requalification process of their pipelines before reuse. The estimated potential within this project is likely to change as the knowledge basis for transport of both H_2 and CO_2 increases and as standards evolve depending on ongoing research activities, testing and studies.

[4] Indeed, several producers connected to several consumers is a better model for the development of a market and to ensure security of supply.

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Abbreviations

AACE	Association for the Advancement of Cost Engineering
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ATR	Autothermal Reforming
bara	Absolute bar
CAPEX	Capital Expenditures
CCS	Carbon Capture and Storage
CEPCI	Chemical Engineering Plant Cost Index
CO_2	Carbon dioxide
CVN	Charpy V-notch energy
EHB	European Hydrogen Backbone
EIGA	European Industrial Gases Association
ES	Spain
EU	European Union
E-PRTR	European Pollutant Release and Transfer Register
FR	France
GCCSI	Global CCS Institute
Gt	Giga tonnes (billion tonnes)
H_2	Hydrogen
JIP	Joint Industry Project
kWh	Kilowatt-hour
LNG	Liquefied Natural Gas
MAOP	Maximum Allowable Operating Pressure
MEUR	Million Euro
Mt	Mega tonnes (million tonnes)
MW	Megawatt
MWe	Electric megawatt
NG	Natural Gas
NL	Netherlands
OD	Outer Diameter
OPEX	Operational Expenditures
Pa	Arrest pressure
Ps	Saturation pressure
PT	Portugal
RFO	Ready For Operation
SMR	Steam Methane Reforming
TSO	Transmission System Operators
TWh	Terawatt-hours
UGS	Underground Gas Storage
UK	United Kingdom
wrt	With regards to
WT	Wall Thickness

1. Introduction

1.1 Context of the study

In the European Green Deal, the EU has set itself the ambitious target of achieving climate neutrality by 2050, with an intermediate target of reducing net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels.[5] The ambition of the EU increases the necessity of decarbonizing the industry, energy and transportation in Europe. Carbon Capture and Storage (CCS) and carbon-free energy carriers based on hydrogen are technologies which could significantly contribute to achieving the EU goals. Both CCS and large-scale hydrogen usage require transportation infrastructure. Reusing existing oil and gas infrastructure could lead to more cost-efficient deployment of CCS and hydrogen technologies and limit the costs of achieving EUs climate ambitions. Decision makers should have access to reliable data to be able to assess the different options of infrastructure reuse.

IOGP / GIE / ENTSOG / CONCAWE, referred to as “the Associations”, commissioned an overview of existing onshore and offshore oil and gas infrastructure in Europe with their potential for reuse for transport (transmission) of CO_2 and hydrogen, and any technical challenges and investment needs associated with such reuse. Carbon Limits in partnership with DNV carried out this study.

1.2 Objective of the study

The aim of the Re-Stream study is to identify relevant infrastructure for reuse in Europe and define what it would take from both technical and economic perspectives to unlock this potential. Together with an assessment of the potential for carbon capture and hydrogen usage around the infrastructure, the study lays the data foundations for further analysis of different value chain scenarios using existing or new infrastructure.

The main objectives of this study are:

- To assess the potential for reuse of infrastructure in Europe (EU 27, UK and Norway) for CO_2 and hydrogen transport by mapping infrastructure and assessing its potential availability (before reuse), compatibility and capacity (if reused);
- Identify CO_2 and hydrogen storage potential around the identified reusable infrastructure and which CO_2 emitters and potential hydrogen users could benefit from the reuse of this infrastructure;
- To perform economic assessments of reuse compared to new build for some specific case studies;
- To identify remaining technical challenges and mitigation options associated with the reuse of infrastructure for CCS and hydrogen projects.

The overall idea is to provide at high-level fact-based results (technical and cost) to inform the EU policy debate.

The term infrastructure, in this report, is mostly used for onshore and offshore pipelines.

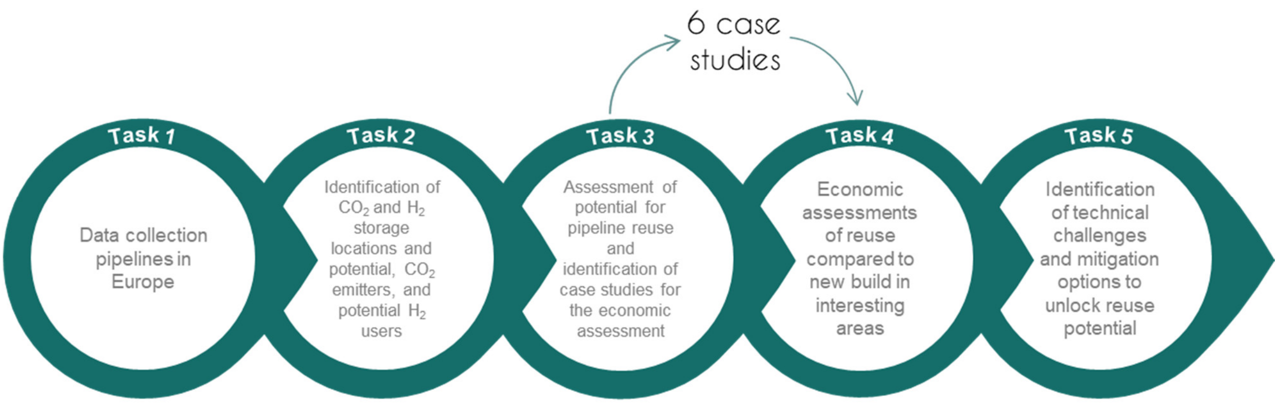
[5] https://ec.europa.eu/commission/presscorner/detail/en/ip_21_1828

1.3 Approach

In order to reach the objectives stated above, 5 tasks were undertaken:

1. Data collection and mapping of existing pipelines in Europe;
2. Identification of CO_2 and H_2 storage locations and potentials, CO_2 emitters and potential H_2 users;
3. Assessment of potential for pipeline reuse and identification of case studies for the economic assessment;
4. Economic assessment of reusing existing pipelines and storage locations compared to new build, for relevant cases (6 cases);
5. Identification of technical challenges and mitigation options to unlock the reuse potential.

Figure 1 - Re-Stream approach



In the following sections, the methodologies and results of each of the tasks are described. In the first part, the data collection process is presented. Afterwards, an initial high-level screening is carried out based on the technical data collected on the different pipelines. In order to assess the business potential of infrastructure reuse, the next part describes the identification of the locations and quantities of sources / producers and sinks / consumers. The selection of cases for further economic assessment is then explained and the methodology and results of the assessment given. Finally, the technical challenges that could face an operator before reusing its pipelines are set forth and mitigation options proposed.

2. Data collection process

The Associations represent most crude oil / oil product and gas pipelines, onshore and offshore in Europe. Data collection processes were launched towards members from:

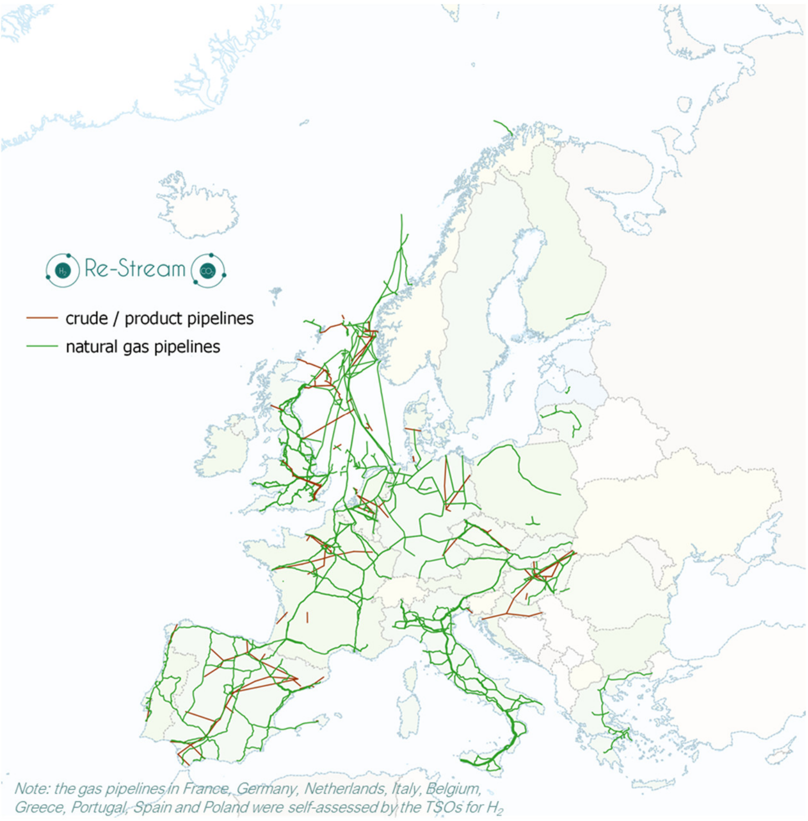
- IOGP for offshore oil and gas pipelines,
- CONCAWE for onshore crude / product pipelines and,
- ENTSOG for onshore gas pipelines.

To perform the high-level reuse assessment, the data collected included as a minimum: the material of construction, basic design data (the maximum allowable operating pressure (MAOP), the diameter and thickness of the pipes) and length. In addition, the operators were asked to specify the pipe condition and age. When a pipeline is made of several materials of construction the lowest and highest grades were considered for the assessment.[6] Regarding thickness, the minimum thickness has been used in the assessment.

All in all, 65 pipeline operators participated in the Re-Stream study, providing data that could be analysed within the Re-Stream project for approximately 58,000 km of pipelines[7] (+24,200 km assessed by operators themselves as suitable for H_2 reuse[8]) representing half of the total offshore pipeline length and approximately 30% of the onshore oil and gas pipelines.[9] Some operators provided data for all their pipelines while some others provided data for the pipelines that could become available soon. The length covered in the Re-Stream project is a good sample of the oil and gas pipeline network in Europe.

[6] A conservative approach was adopted for the consideration of the steel grades in the screening depending on the transported fluid. See section 3.1.
[7] 28,800 km of onshore gas pipelines / 12,900 km of crude/product onshore pipelines / 16,300 km offshore pipelines of which 13,570 km of gas pipelines
[8] Several operators that provided data to the Re-stream study have been / are assessing internally the reusability of their pipelines for H_2 and CO_2. Results from the Re-stream study should not prevail on operators' results considering the operators have access to more detailed data than the Re-stream team.
[9] For onshore gas pipelines, the data collection focused on the pipelines that may become available for transport of other products than gas in the next 20 years. Offshore, data were collected for all pipelines.

Figure 2 – Crude / product and gas pipelines considered in the Re-Stream study



The data for most of the pipelines were collected under non-disclosure agreements and are presented in an aggregated way to protect confidential information. As illustrations, Figure 3 and Figure 4 show the distributions of material of construction and of material of construction for oil and gas pipelines onshore and offshore.

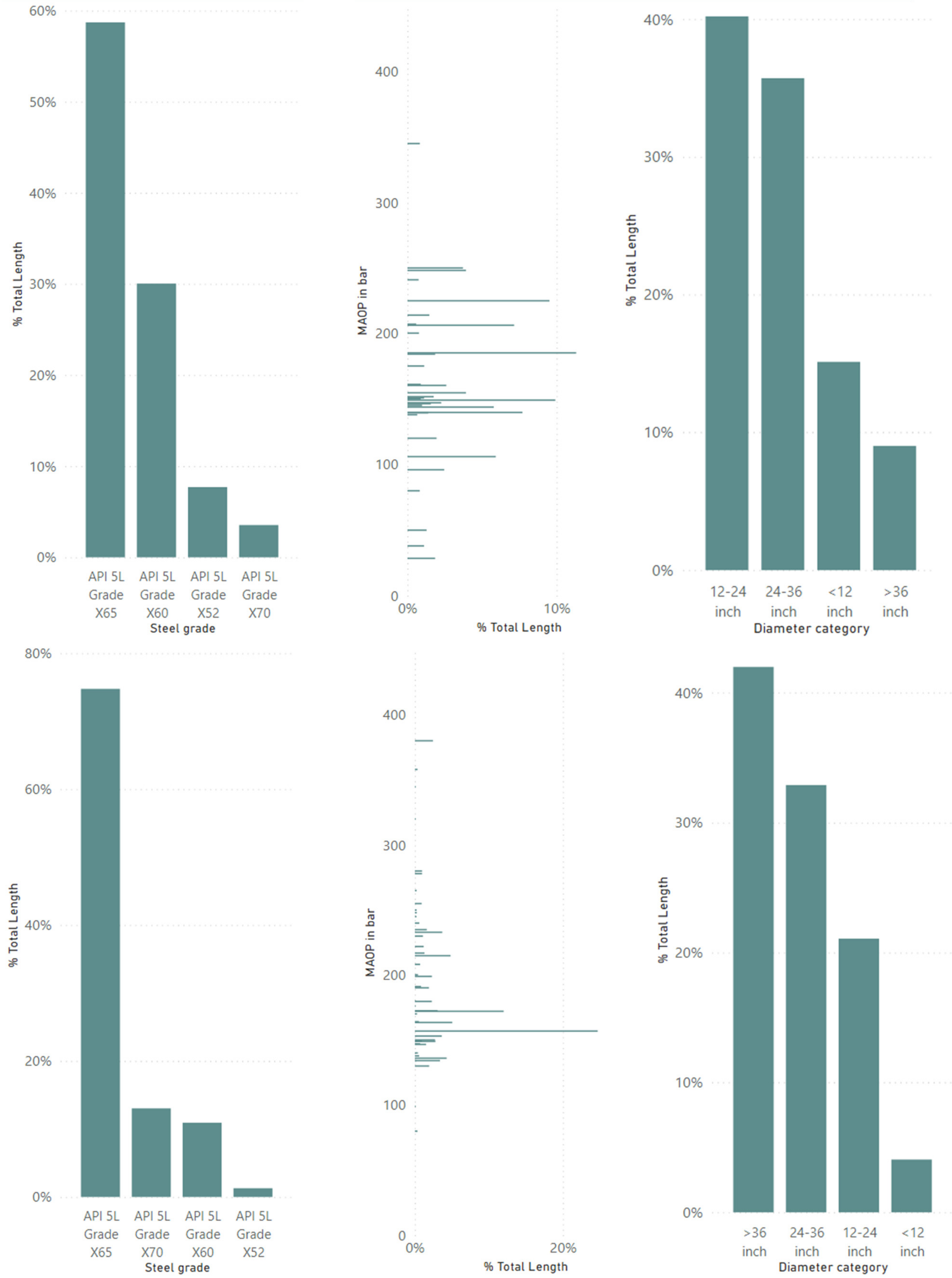
Close to 90% of the offshore pipelines are either made of X65 or X60 steel (Figure 3). The main material of construction offshore is the API 5L grade X65 for both oil and gas pipelines. The median MAOP is around 150 bar for offshore oil pipelines and 160 bar for offshore gas pipelines. Regarding external diameters, most of the offshore oil pipelines have diameters ranging from 12 to 36 inch whereas most of the offshore gas pipelines in the North Sea have diameters above 24 inch (long export gas pipelines).

The same analysis was carried out for the onshore pipelines (Figure 4). The materials of construction for onshore crude/product pipelines are more varied with almost 50% of crude pipelines in API 5L grade X52, but with a range of pipelines with low-grade steel (X42) to higher grade steels (X70). With regards to the MAOP, the onshore pipes tend to have lower MAOP with a median around 70 bar and a range between around 40 bar to 140 bar depending on the pipeline. Most of the crude / product pipelines have external diameters between 12 and 24 inch.

The onshore gas pipelines included in the study have less variety in material types and less dispersion in MAOP (more integrated network). Around 45% of the onshore gas pipelines are made of X60 steel grade with for the rest of the pipelines steel grades ranging from X52 to X80. As for crude/product pipelines, the median MAOP for onshore gas pipelines is around 70 bar. The MAOP range is however less dispersed with pressure ranging from 40 bar to 100 bar. Regarding external diameters, among the analysed pipelines, the distribution for onshore gas pipelines is more spread with diameters ranging from less than 12 inch to more than 36 inch.

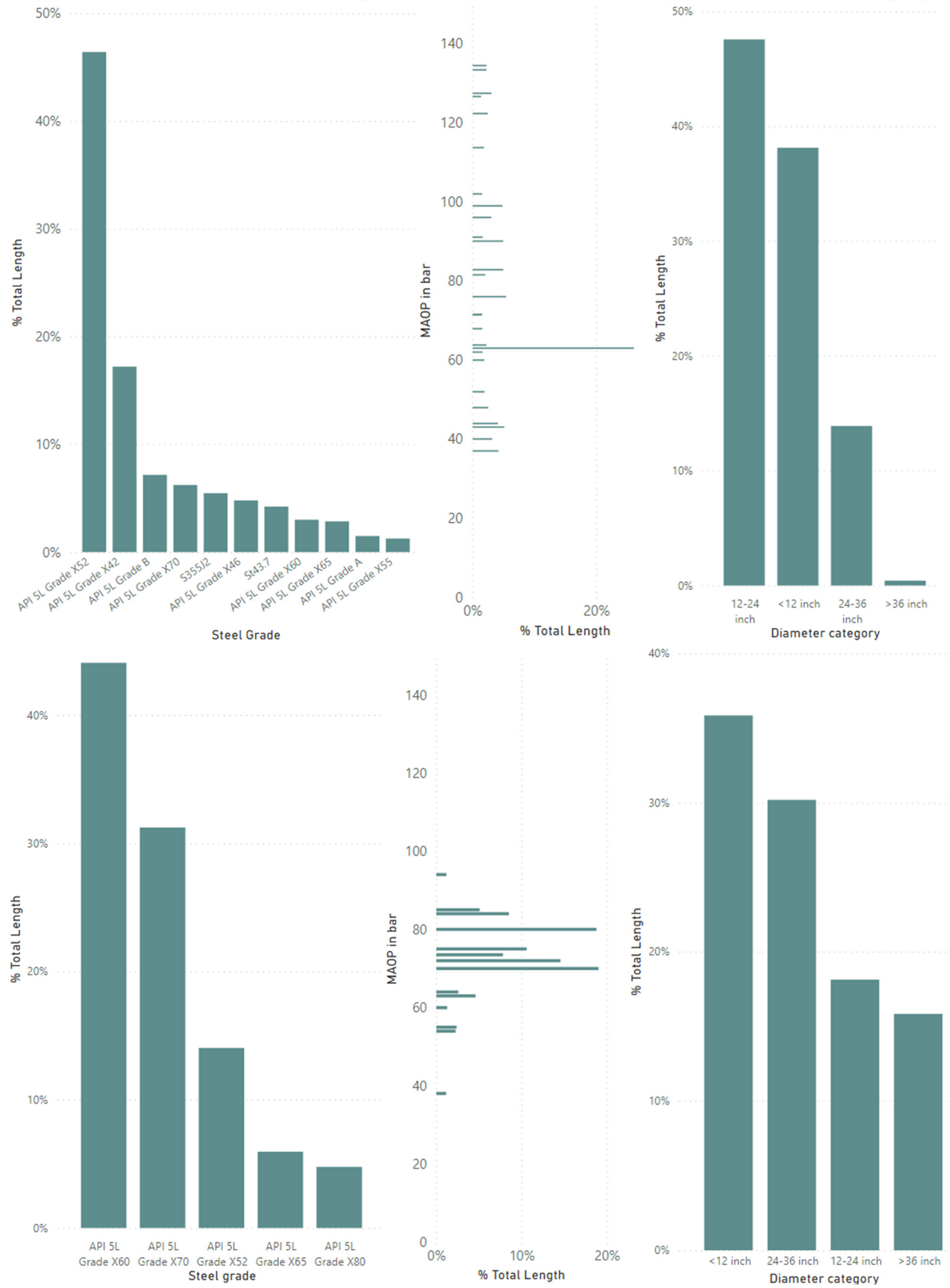
Based on the data collected an initial screening was performed and is detailed in section 3.

Figure 3: Distribution of materials of construction, Maximum allowable Operating Pressures (MAOP) and external diameters for offshore oil (incl. condensate) pipelines (top graphs) and offshore gas pipelines (bottom graphs) – Only material representing more than 1% of the length appear on the graphs. Total length top graphs = 3,300 km- Total length bottom graphs = 13,000 km



Source: data provided by IOGP members, Carbon Limits Analysis

Figure 4: Distribution of materials of construction, Maximum allowable Operating Pressures and external diameters for onshore crude/product pipelines (top graphs) and onshore gas pipelines (bottom graphs) – Only material representing more than 1% of the length appear on the graphs. Total length top graphs = 12,900 km- Total length bottom graphs = 28,800 km



Source: data provided by CONCAWE and ENTSOG members, Carbon Limits Analysis

3. Initial screening criteria and results

In order to assess the suitability of the pipelines to transport H_2 or CO_2, a screening was performed based on a scoring approach and a series of criteria (related to material, design, safety, operation and transport capacity) described in this section. This initial screening is a technical screening and does not take into account the locations of the sources / producers and sinks / consumers.

The screening was performed for each of the following scenarios:

- transport of CO_2 in dense phase (i.e. liquid or supercritical fluid)
- transport of CO_2 in gas phase
- transport of H_2 in gas phase (100% H_2)

For each criterion, a score is given between 0 and 1. The final score for the pipeline is the product of the scores of the different criteria. If the pipeline does not fulfil the criteria, a penalty is given, i.e. the score for this criterion will be lower than 1. Implicitly a total score of 0 will be the result of one of the criteria scoring zero. A zero is an eliminatory score. The scores were given based on discussions with different experts (material, flow assurance, pipeline, etc.) in the contractors' teams, and feedback from the operators during the study.

The following should also be noted:

- The screening assessment is based on current knowledge and standards.
- The methodology developed for the scoring only includes criteria that can be assessed based on the data collected for the pipelines (basic design data, length, material, condition, age).
- As with any high-level screening method, there is a certain degree of uncertainty and engineering judgement involved.
- A list of technical challenges for pipeline reuse, including criteria that cannot be covered at screening stage, are listed and discussed in section 7.
- For hydrogen transport, 100% H_2 within transmission pipelines is considered as the focus of the study. Blending of H_2 with natural gas is discussed in Box 1.

3.1 Screening criteria

The considered screening criteria for reuse of pipeline for CO_2 transport are given in Table 1. When the criterion is only applicable to CO_2 transport in dense phase, this is clearly stated in the table. Reference is made to the recommended practice *DNVGL-RP-F104 Design and operation of carbon dioxide pipelines* which gives a framework for new build or requalification of existing pipelines for transport of CO_2 and to *ISO 27913:2016 (Carbon dioxide capture, transportation and geological storage — Pipeline transportation systems).*

The considered screening criteria for reuse of pipeline for H_2 transport are given in Table 2. The considered criteria and screening are valid for 100% H_2 transport. Reference is also made to *ASME B31.12 Standard on Hydrogen Piping and Pipelines*. This standard is applicable to onshore pipelines (though it was initially developed for short H_2 transport pipelines) and there is currently no standard specific to offshore H_2 pipelines. DNV is currently running a JIP (Joint Industry Project) for the development of a recommended practice specific to the design and operation of offshore hydrogen pipelines (Phase 1 including draft guideline and initial test program to be completed in 2022).

Other parameters such as, among others, the chemical composition, the heat treatments of the material, the welding procedure specification, the way a pipeline has been operated over the years are also factors that play an important role in the possibility for reuse of a pipeline. However, these parameters could not be considered at screening level.

Table 1 – Screening criteria for CO_2 transport (gas or dense phase CO_2; when a criterion is only relevant to dense phase, it is clearly specified)

<table>
<tr><th>Criteria</th><th>Comments</th></tr>
<tr><td>Running ductile fracture</td><td>This criterion is only relevant for CO₂ transport in dense phase. It is included to confirm if the pipeline design has sufficient resistance against running ductile fracture. For the criterion to be fulfilled, the arrest pressure of the pipeline should be higher than the saturation pressure of the CO_2 composition: Pa > Ps.

The saturation pressure can be taken conservatively as the critical point pressure for pure CO_2 + some safety margin to compensate for the effects of impurities: For the screening, 80 bar saturation pressure has been used.

A simplified Battelle formula[10] has been used to estimate the arrest pressure:
$$p_a = \frac{2 \cdot t \cdot \tilde{\sigma}}{3.33 \cdot c_f \cdot \pi R_o} \cos^{-1}\left[e^{\left(\frac{-\pi R_f E}{24\tilde{\sigma}^2\sqrt{R_o \cdot t}}\right)}\right]$$
The parameters and properties required for this analysis are the pipeline wall thickness t, the outer pipeline radius Ro, the “fracture toughness” per fracture area Rf, related to the Charpy V-notch energy (CVN), the yield strength σo, the “material flow stress” σ, the elasticity E, and a safety factor c_f (taken as 1.2).

When a pipeline is made of several materials of construction the lowest steel grade was conservatively considered.

Material properties vary between pipelines and all detailed data (CVN values) were not available for the screening.

If the arrest pressure is below the saturation pressure, the pipeline should not be operated in dense phase. However, a score of 0 has not been applied to fully disqualify the pipeline as further actions can be considered: additional testing, reduce some conservatism in the formula, use of crack arrestor (etc...).</td></tr>
<tr><td>Transport in dense phase</td><td>This criterion is only relevant for CO₂ transport in dense phase.

This is to check if the maximum operating pressure (MAOP) per current design of the pipeline is sufficient to enable transport of CO_2 in dense phase. A comparison of the MAOP to the critical pressure was carried out. If the MAOP is below the critical pressure, then transport of CO_2 is not possible in the dense phase.

The critical pressure is impacted by the CO_2 feed composition and temperature conditions along the line. This cannot be accounted for in the screening but can be checked individually when doing a more detailed assessment of a specific pipeline. If the MAOP is above but too close to the critical pressure, it should however be noted that there will be limited benefit in terms of capacity for transporting the CO_2 in dense phase as compared to gas phase.</td></tr>
<tr><td>Internal pipeline condition</td><td>This criterion is based on internal pipeline inspection and is used to reflect the state of the pipeline with regards to internal corrosion. A penalty is applied in case of non-negligible internal corrosion.</td></tr>
<tr><td>Safety as compared to existing fluid</td><td>This criterion is used to reflect the fact that it may be easier to requalify the pipeline with regards to safety aspects if the new fluid is in the same fluid category as the existing one (gas vs. liquid pipelines). A penalty is applied if it is otherwise.</td></tr>
<tr><td>Safety w.r.t. location class</td><td>This criterion is used to reflect the safety risk with regards to location class along the pipeline route.

As the details of the location class along the pipeline (based on population density) is not available for the screening, the only distinction made at this stage is between offshore and onshore pipelines.</td></tr>
</table>

[10] Geir Skaugen, Simon Roussanaly, Jana Jakobsen, Amy Brunsvold (SINTEF Energy Research), 2016 “Techno-economic Evaluation of the Effects of Impurities on Conditioning and Transport of CO2 by Pipeline”.

Criteria	Comments
Operation	*This criterion is only relevant for dense phase CO_2.* This is to reflect the fact that there are less seasonal variations of ambient temperature for offshore pipelines, and that there might be less limitation in terms of operational envelope to maintain the CO_2 in dense phase. *The range of temperature considered for the transported CO_2 is around ambient temperature (< 30 °C). Equipment (cooler) may be needed upstream of the pipeline to maintain the fluid within acceptable temperature limits and avoid the two-phase region.*
Pipeline age	This criterion reflects the fact that it may be difficult to retrieve all necessary information for a full requalification if the pipeline is very old (for example, if there has been a change of ownership of the pipeline during its lifetime, or if some information is difficult to retrieve because they have not been digitized). In addition, the age is also an indicator for the stress cycles experienced in fatigue or external loading sensitive areas. The age of the pipeline is however not the only factor in the definition of the pipeline behavior in the future. Other parameters are also very relevant, for example the way a pipeline has been designed, built, tested and above all operated in the years because the frequency and the load ratio can be very different for different pipelines. These items could however not be accounted for in the screening. Penalties were applied for pipeline installed prior to 1990.
Transport capacity (1^{st} check)	This criterion is further assessed at business case level. A first check is however performed here at screening level to confirm if any lines can be disregarded due to very limited transport capacity. ▪ For the CO_2 transport capacity in dense phase, the following assumptions are considered for the transport capacity estimates: * inlet pressure=pipeline current MAOP, * outlet pressure assumed to be 80bar (to still be in dense phase with some margin), * internal pipeline roughness=50microns, * considered limit on velocity for CO_2 dense phase: 5m/s ▪ For the CO_2 transport capacity in gas phase, the following assumptions are considered for the transport capacity estimates: * inlet pressure=40bar (sufficient margin from the dew point curve), * outlet pressure assumed to be minimum 20bar, * internal pipeline roughness=50microns, * considered limit on velocity for CO2 gas phase: 10m/s. Only pipelines being able to transport at least 0.01 $MtCO_2$/y qualified at screening stage.

Table 2 – Screening criteria for H_2 transport

Criteria	Comments
Hydrogen embrittlement + Material hardness	This criterion is used to reflect the challenges for higher grade steel with regards to hydrogen embrittlement and loss of ductility, as well as the current limitation on the hardness of the material as per ASME B31.12. • EIGA 121/14, applicable to new hydrogen pipelines, recommends API 5L grades up to X52. In AMSE B31-12, additional material tests are required (performance-based method) to avoid penalty on the material performance factor in case of higher-grade steels with H_2 transport. In general, there is also less experience on the use of higher-grade steels for H_2 transport. • In addition, in ASME B31.12, there is a limitation on the Vickers hardness of the material which will be challenging to fulfil for higher grade steels. The Vickers hardness should be less than 235 HV10 for carbon steel for hydrogen transport. *There is a general agreement amongst material experts of the participating operators that the criteria defined in ASME B31.12 are very conservative regarding the behavior of high-grade steel in the presence of hydrogen. For this reason, it is important to note that there is ongoing research on the use of higher-grade steels (X65, X70 and above) for the transport of hydrogen. The additional material testing and potential updates of the standards may facilitate the reuse of pipelines with higher grade steels, and the scoring for this criterion will need to be updated accordingly. The effect of a possible increase in material hardness in hydrogen environment should also be evaluated.* For the scoring of this criteria related to the steel grade, higher grade steels have not been disqualified but are given a lower score due to the current state of knowledge/standards. Penalties are used to differentiate which pipelines may represent more technical challenges with regards to the material requirements in the current version of ASME B31.12. When a pipeline is made of several materials of construction the highest steel grade was conservatively considered.
Internal pipeline condition	This criterion is based on internal pipeline inspection and is used to reflect the state of the pipeline with regards to internal corrosion. A penalty is applied in case of *non-negligible internal corrosion.*
Safety as compared to existing fluid	This criterion is used to reflect the fact that it may be easier to requalify the pipeline with regards to safety aspects if the new fluid is in the same fluid category as the existing one. (gas vs. liquid pipelines). A penalty is applied if it is otherwise.
Safety w.r.t. location class	This criterion is used to reflect the safety risk with regards to the location class along the pipeline. As the details of the location class along the pipeline (based on population density) is not available, the only distinction made at this stage is between offshore and onshore pipelines.
Available process infrastructure	In case of existing gas pipeline, it may be possible to re-use some other parts of the system, i.e. additional infrastructure in addition to the pipeline system. This is noted positively in the scoring.
Pipeline age	This criterion reflects the fact that it may be difficult to retrieve all necessary information for a full requalification if the pipelines that are very old (for example, if there has been change of ownership of the pipeline, and if some information are difficult to retrieve because they have not been digitalized). In addition, the age is also an indicator for the stress cycles experienced in fatigue or external loading sensitive areas. The age of the pipeline is however not the only factor in the definition of the pipeline behavior in the future. Other parameters are also very relevant, for example the way a pipeline has been designed, built, tested and above all operated in the years because the frequency and the load ratio can be very different for different pipelines. These items could however not be accounted for in the screening. Penalties were applied for pipeline installed prior to 1990.

Criteria	Comments
Transport capacity (1st check)	This criterion is further assessed at business case level. A first check is performed here at screening level to see if any lines can be disregarded due to very limited transport capacity. For the H_2 transport capacity, the following assumptions are considered for the capacity estimates: * Inlet pressure=new MAOP calculated based on AMSE B31.12 with the prescriptive method (accounting for the material performance factor and usage factor), * outlet pressure assumed to be minimum 15bar, * internal pipeline roughness=50microns, * considered limit on velocity for H_2 in gas phase: 40m/s Only pipelines being able to transport at least 0.01 MtH_2/y qualified at screening stage.

3.2 Screening results

Depending on the scores calculated following the methodologies described above three categories of pipelines have been defined:

A. The pipelines reusable considering the current state of knowledge/standards.
B. The pipelines that would require more testing and/or update of standards to be reusable.
C. The pipelines not reusable.

Categories A and B pipelines will still require a proper requalification process (including but not limited to a more detailed integrity assessment of the pipeline) to finally confirm their reusability for H_2 or CO_2 but are promising pipelines for reuse. During a more detailed assessment, some pipelines could be disqualified due to for example further information on the integrity status of the pipeline, assessment of fatigue crack growth for H_2 service, running ductile fracture for CO_2 and timing (date of availability of the pipeline for other use).

CO_2 transport

The total pipeline lengths in each group for pipelines in categories A and B are given in Table 3 for CO_2 transport. The average CO_2 transport capacity ($MtCO_2$/y) per pipeline in each pipeline group (offshore, onshore oil, onshore gas) is also indicated.

The main drivers for CO_2 transport in dense phase are the criteria on running ductile fracture and the criteria on current MAOP (i.e. comparison of the current MAOP with the pressure requirement for transport in dense phase). As can be seen, the potential for CO_2 transport in dense phase is governed by the offshore pipeline category. This is due to the higher wall thickness and higher MAOP in this category (median MAOP around ~150bar for the offshore pipeline category compared to ~80bar for the onshore pipeline categories).

Few technical design limitations were identified for CO_2 transport in gas phase, which is reflected by all pipelines falling in the Category A. Regarding the operational aspects, the requirement for sufficient water dew point and composition control is emphasized.

The difference in transport capacity for dense phase CO_2 transport versus gas phase CO_2 transport is clearly shown for the different types of pipelines. The difference observed in average transport capacity in each group is to some extent due to the difference in average diameter in each pipeline group.

Table 3 – Initial screening results summary for CO_2 for pipelines in category A and B (A= pipelines reusable considering the current state of knowledge/standards, B= pipelines that would require more testing and/or update of standards to be reusable)

Parameter	Offshore pipelines		Onshore gas pipelines		Onshore oil/product pipelines	
	If dense phase	If gas phase	If dense phase	If gas phase	If dense phase	If gas phase
Average CO_2 transport capacity ($MtCO_2$/y) cat. A+B	22	1.5	19	2.5	2.5	0.8
Total pipeline length (km) cat. A	9,250	16,370	370	27,600 (+1,000)	100	12,900
Total pipeline length (km) cat. B	6,920	/	4,240	/	5,290	/
Total pipeline length assessed (km)	16,370		27,600 (+1,000)		12,900	

Note 1: this table shows only the results for the 58,000 km assessed within Re-Stream based on complete dataset. As such, it does not include the statistical sets. This could represent significant additional length to be reused.
Note 2: the pipelines self-assessed by TSOs are in between brackets.
Note 3: the assumptions made for the transport capacity are given in Table 1. Note that the capacities were calculated for individual pipeline sections.
Source: data provided by pipeline operators, Re-Stream team analysis

100% H_2 transport in gas phase

The total pipeline length in each group for pipelines in categories A and B is given in Table 4 for H_2 transport. The average H_2 transport capacity (TWh/y) per pipeline in each pipeline group (offshore, onshore oil, onshore gas) is also indicated.

The difference observed in average transport capacity in each group is to some extent due to the difference in average diameter in each pipeline group.

The main driver for the screening is the material steel grade. The on-going research on the material aspects is expected to reduce some uncertainties and unlock further the potential for reuse.

During a more detailed assessment, some pipelines could be disqualified due to for example further information on the integrity status of the pipeline, assessment of fatigue crack growth for H_2 service, timing (non-availability of the pipeline for other use), etc.

Table 4 – Initial screening results summary for 100% H_2 for pipelines with score in category A and B (A= pipelines reusable considering the current state of knowledge/standards, B= pipelines that would require more testing and/or update of standards to be reusable)

Parameter	Offshore pipelines	Onshore gas pipelines	Onshore oil/product pipelines
Average H_2 transport capacity (TWh/year) cat. A+B	14	23	7
Total pipeline length (km) cat. A	15,700	17,910 (+24,200)	11,500
Total pipeline length (km) cat. B	670	10,890	1,400
Total pipeline length assessed (km)	16,370	28,800 (+24,200)	12,900

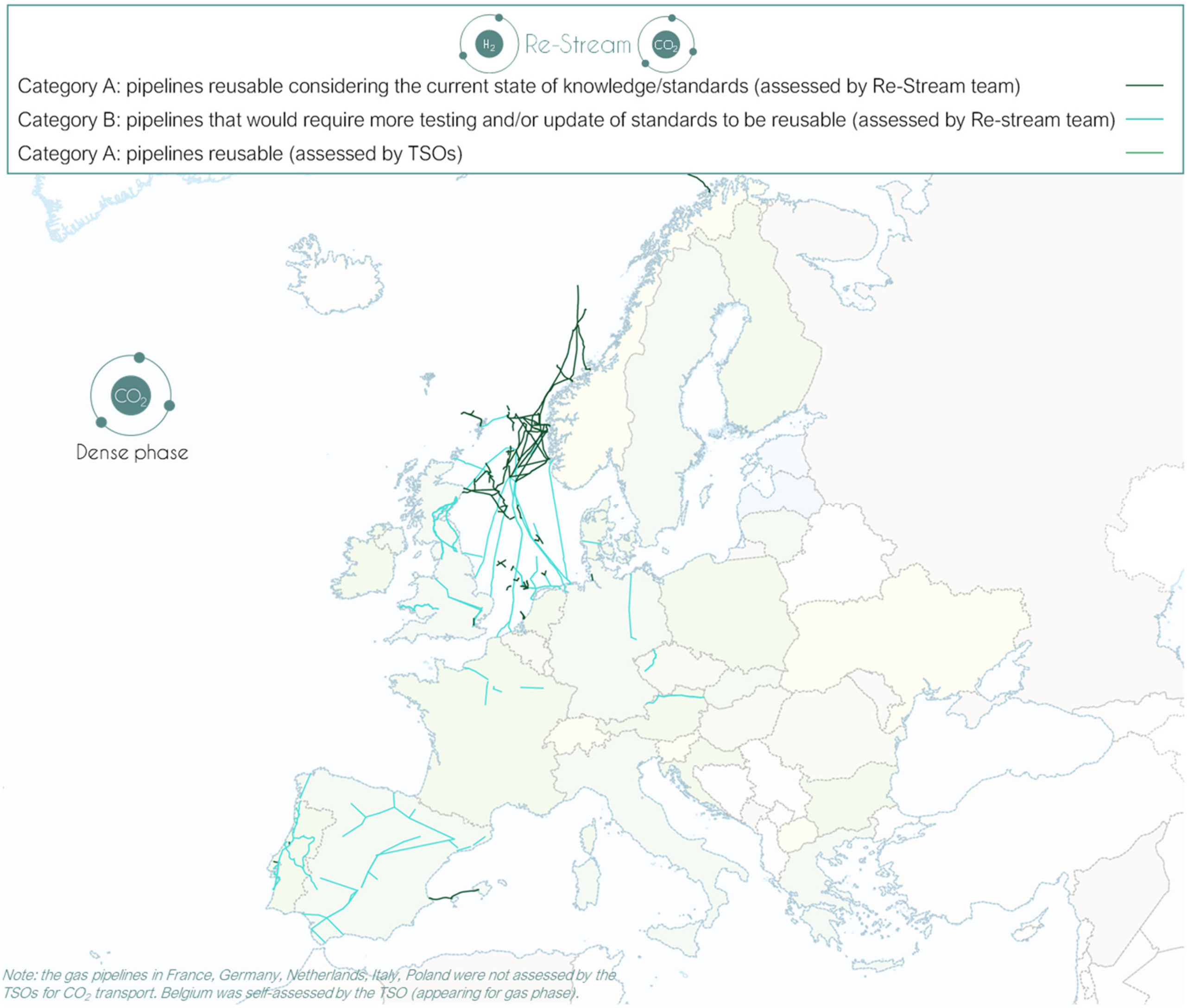
Note 1: this table shows only the results for the 58,000 km assessed within Re-Stream based on complete dataset. As such, it does not include the statistical sets. This could represent significant additional length to be reused.
Note 2: the pipelines self-assessed by TSOs are in between brackets.
Source: data provided by pipeline operators, Re-Stream team analysis
Note 3: the assumptions made for the transport capacity are given in Table 2. Note that the capacities were calculated for individual pipeline sections.
Source: data provided by pipeline operators, Re-Stream team analysis

It should be noted that as of today none of the analysed pipes are excluded from being reusable for H_2.

3.3 Maps with results of screening

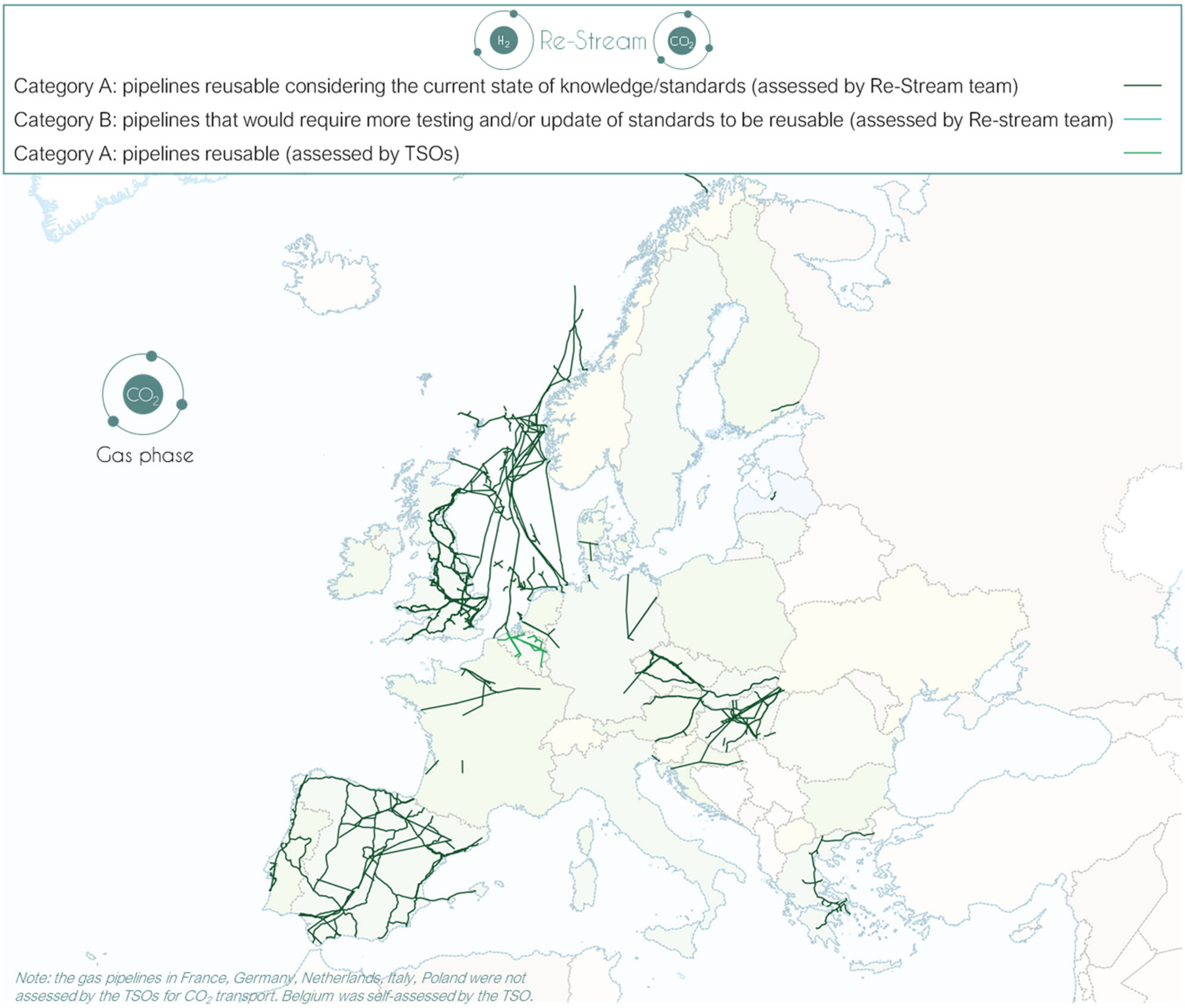
Maps showing the category A and B pipelines have been developed within the Re-Stream project for CO_2 in the gas phase (Figure 6), CO_2 in the dense phase (Figure 5) and 100% H_2 (Figure 7). Other pipelines (not assessed within the Re-Stream study) are likely to be reusable.

Figure 5 - Re-Stream assessment of reuse of oil and gas pipelines for CO_2 transport in the dense phase



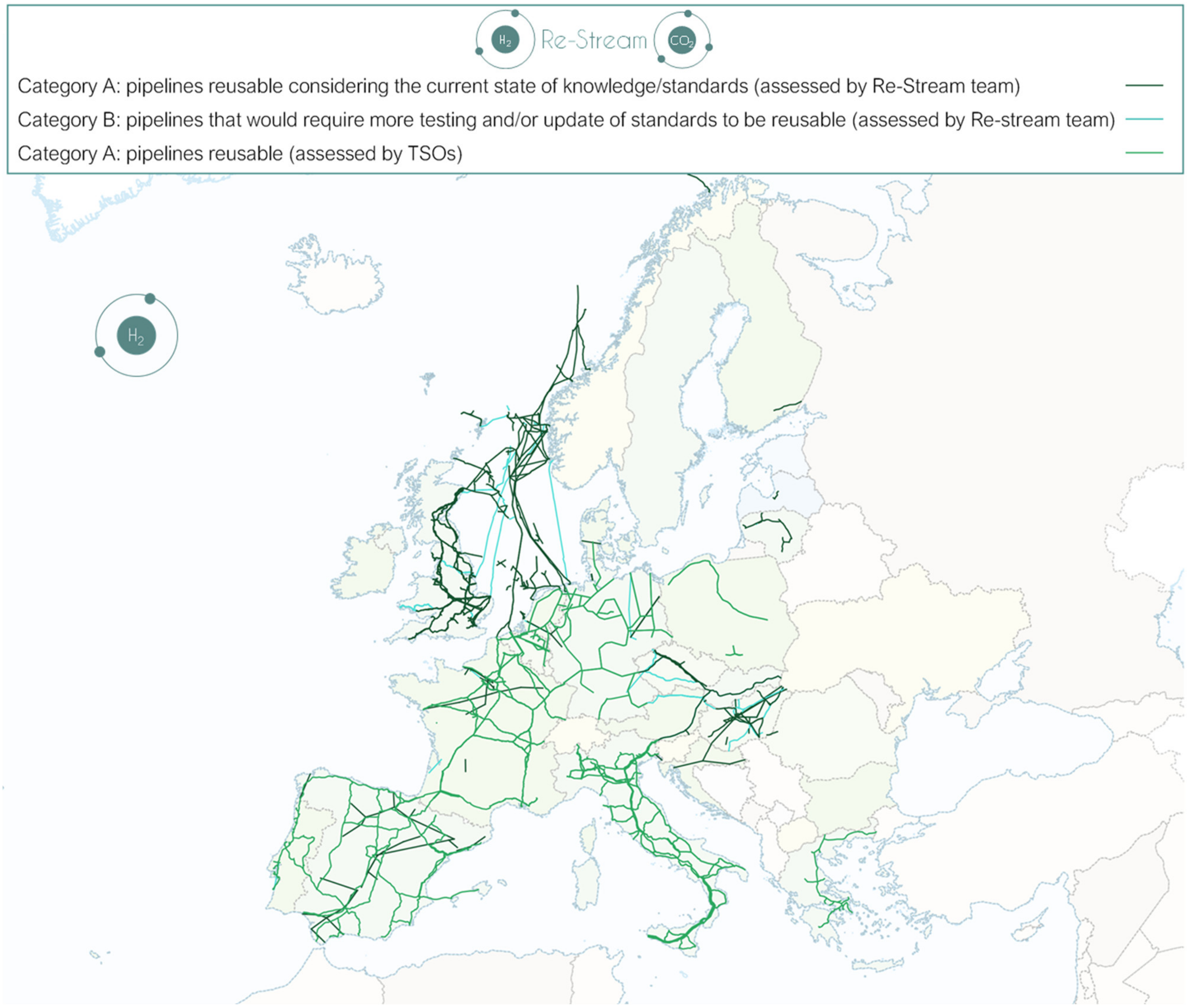
Source: data provided by pipeline operators, Re-Stream team analysis

Figure 6 - Re-Stream assessment of reuse of oil and gas pipelines for CO_2 transport in the gas phase



Source: data provided by pipeline operators, Re-Stream team analysis

Figure 7 - Re-Stream assessment of reuse of oil and gas pipelines for 100% H_2 transport



Source: data provided by pipeline operators, Re-Stream team analysis

Hydrogen/Natural gas blending

In the Re-Stream study, the focus is on large scale transport of H_2 in transmission pipelines and both gas and oil pipelines are considered for their reuse potential. Hence, 100% H_2 transport has been considered in the study.

For smaller H_2 production and for existing gas pipelines, there is however a potential for blending of H_2 in the natural gas network in the early phase of the H_2 economy development [1]:

- This may be a good solution for valorising small outputs from hydrogen in onshore settings.
- This can provide a boost to hydrogen supply technologies, including a quick scale up of electrolysers and power to gas by taking advantage of existing and reliable natural gas demand.
- Many gas transmission pipelines can accommodate some degrees of H_2 blending.
- In combination with de-blending, blending can be a cost-efficient way to transport H_2 to the industry if a completely new pipeline was the alternative.
- Storing and transporting hydrogen would have very low marginal cost, when using existing infrastructure between 2% - 10% H_2 admixtures.
- This can allow a more flexible use of the electrolysers (vs. industrial cluster processes with constant demand) taking advantage from lower electricity costs.
- There can be a reduction of logistic and productions costs as a consequence of the flexible locations.
- This can enable widespread sector coupling between gas and electricity: flexibility, resilience, dealing with surplus of variable renewable electricity, avoiding power congestions, energy conversion, (seasonal) storage, etc.
- This will help building-up H_2 volumes and developing economies of scale until dedicated H_2 pipeline business case is mature enough. This will also provide learnings for moving quicker towards 100% H_2 grid.

However, as the current limits on hydrogen blending vary significantly between countries, there is a need for clarification of existing regulations and harmonization across borders. The benefits of hydrogen/natural gas blending may also depend on the regional situation. With regards to reduction of CO_2 emissions, the effect of blending must be studied on a case-by-case basis. [1]

H_2 carrier

Alternative methods for transporting H_2 via a carrier may include LOHC (Liquid organic hydrogen carrier) and ammonia.

The use of LOHC's may be relevant for shipping but are potentially less relevant for pipelines due to the need to return the carrier molecules to their place of origin at the end of the process.

Ammonia is easier to transport than hydrogen but comes at an additional cost if it is converted back into hydrogen before use. For new infrastructure with distances below 1,500km, transmission of hydrogen as a gas by pipeline is generally the cheapest option. [2]. In the context of repurposing pipelines, a more recent analysis even indicates that transmission by pipeline would be a cheaper option for distances below 5,000km, [3].

Note that pure liquefied H_2 is only relevant for shipping (liquefied H_2 is at -253°C).

[1] *Open Letter on Hydrogen Blending: https://www.euractiv.com/wp-content/uploads/sites/2/2021/03/Open-Letter-on-Hydrogen-Blending_17-Mar-2021_Final_SENT.pdf*
[2] IEA, *The Future of Hydrogen, 2019. Available at https://www.iea.org/reports/the-future-of-hydrogen*
[3] *Gas for Climate 2050, https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021_v3.pdf*

4. Future facility locations

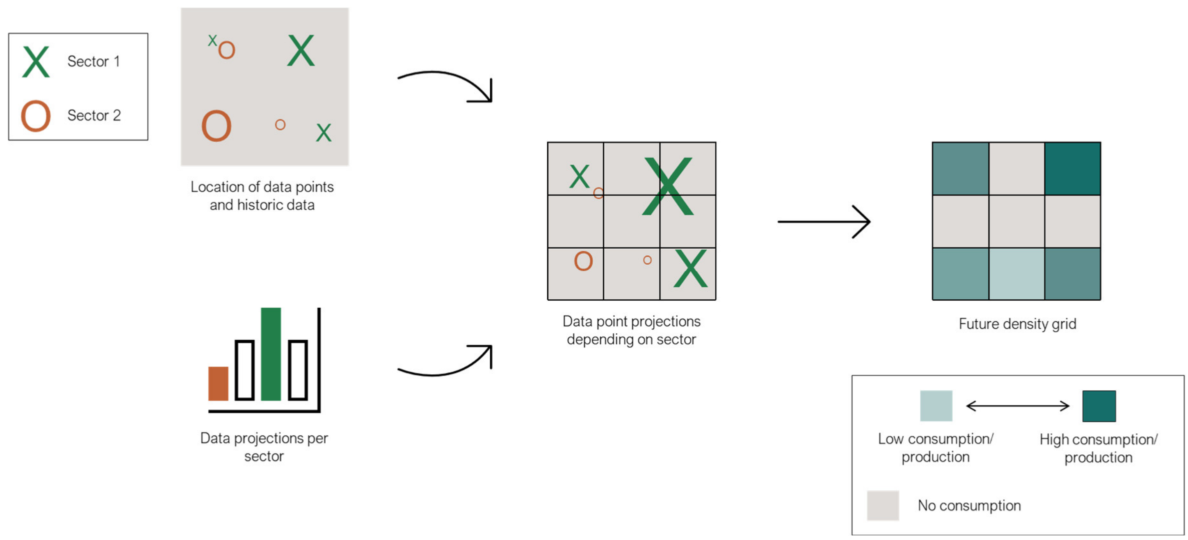
In this chapter facility locations are mapped providing thereby the basis for predicting the most relevant pipeline corridors. Hydrogen facilities include production, buffer storage and end users. Facilities for handling carbon dioxide include capture sites, potential hubs and geological storage sites.

4.1 Mapping methodology

The precise locations of future facilities are not known, but this study attempts to predict some areas that are likely to see development based on current trends and access to physical resources such as offshore wind for hydrogen production and geological storage sites for carbon dioxide.

Locations of existing facilities were categorized according to type and size (annual volumes) and their precise locations were upscaled to a coarser mapping grid that is at a suitable scale of predicting future trends (Figure 8).

Figure 8 - Methodology for upscaling of the mapping grid to produce a density map of future volumes in a given area



Source: Carbon Limits

The location, type and size of future facilities were predicted following the analysis described in the following sections and added to the database of current facilities.

Density maps for 2030, 2040 and 2050 were drawn up based on these predictions.

4.2 Hydrogen facility mapping

Hydrogen is currently an important feedstock in a number of industries and is produced mainly with natural gas. In a decarbonized future, hydrogen is expected to play an important role in several new industries while continuing to serve its existing customers. The challenge will be to produce low-emissions hydrogen to serve these sectors looking to reduce their emissions and ensuring effective emissions reduction across these new value chains.

In the next paragraphs the means of production / consumption / storage are described along with the identification of locations and the allocation of quantities to the locations.

Hydrogen production facilities

Hydrogen is generally produced in situ at the end user location. This is expected to change, introducing the need for hydrogen pipelines within Europe. Production may take place domestically within Europe or volumes may be imported by pipeline or ship from other countries.

This study has taken a two-step approach to mapping the approximate size and location of future hydrogen facilities; first by estimating future annual production for hydrogen in terawatt-hours (TWh), and then by breaking this down by production method. Different methods of production rely on access to different resources that are geographically spread throughout Europe and these dependencies are used to make assumptions about the locations of future production capacity.

Future production of hydrogen

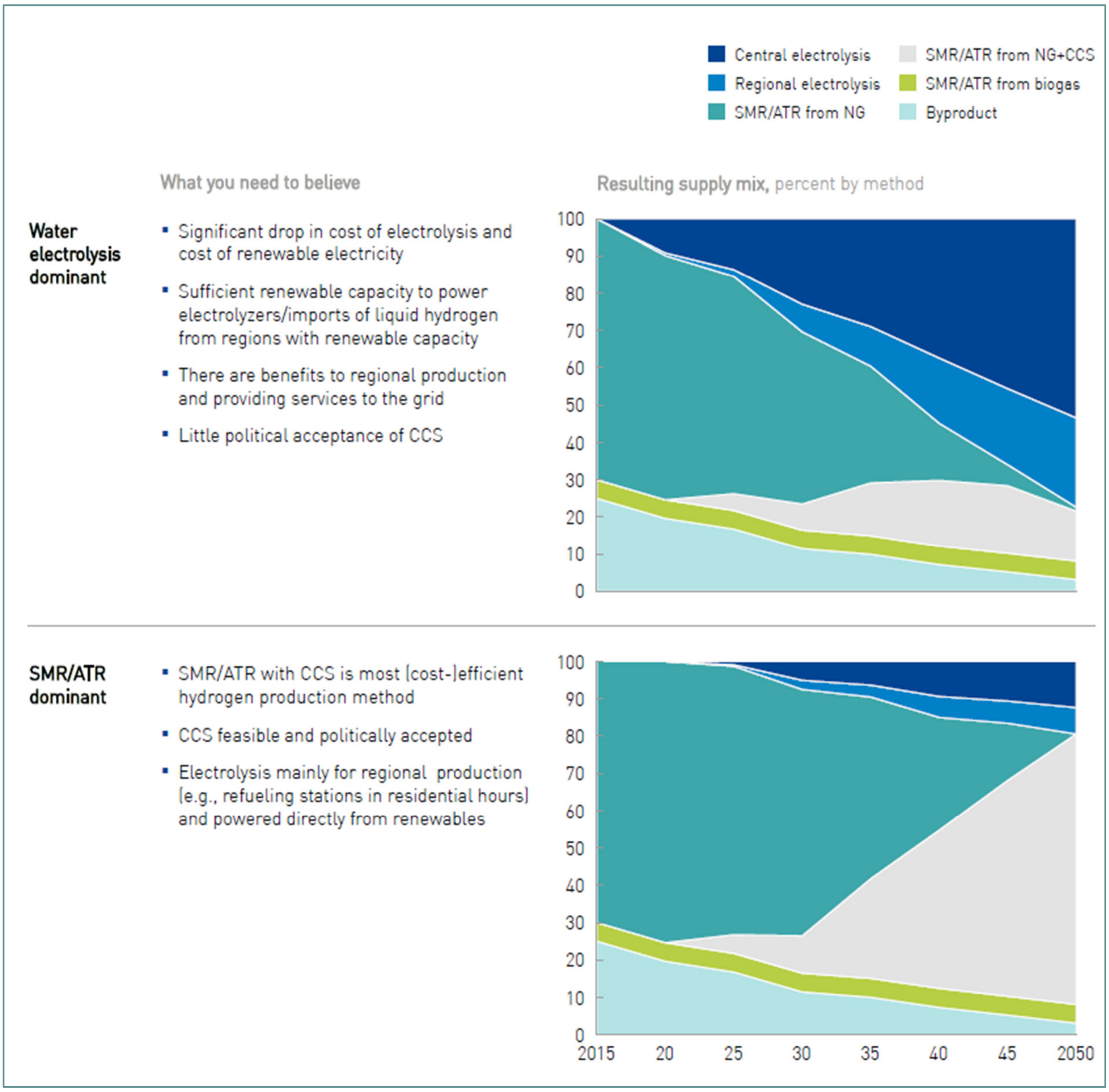
Steam methane reforming (SMR) is currently the dominant source of hydrogen in Europe. This study anticipates that carbon capture and storage will be added to this process in order to remove carbon dioxide emissions (SMR+CCS = “Blue” hydrogen) and electrolysis from renewable power will grow significantly (“Green” hydrogen).

Other climate-friendly methods of hydrogen production are anticipated (for example pyrolysis of methane), but the assumption was taken that such development will not significantly impact choice of production location as pyrolysis could be located at the same locations as SMR.

Figure 9 shows the two scenarios for hydrogen production up until 2050 that Carbon Limits relied on as the basis for the analysis carried out in this study; one where electrolysis dominates and one where SMR dominates. These scenarios are coming from a study realized by the Fuel Cells and Hydrogen 2 Joint Undertaking in 2019.

The assumptions are listed for each case and autothermal reforming (ATR) is treated together with SMR.

Figure 9 - Supply scenarios to model future production of hydrogen[1]. Displayed as % of total supply. SMR/ATR=steam methane/autothermal reforming



Source: Fuel Cells and Hydrogen 2 Joint Undertaking, Hydrogen Roadmap Europe, 2019

Whilst important for determining the share of production, the SMR and electrolysis scenarios from Figure 9 do not provide a basis for predicting a geographical distribution of production capacity within Europe. In order to introduce a geographical component to the analysis, SMR and electrolysis have been divided into the following types of production[11]:

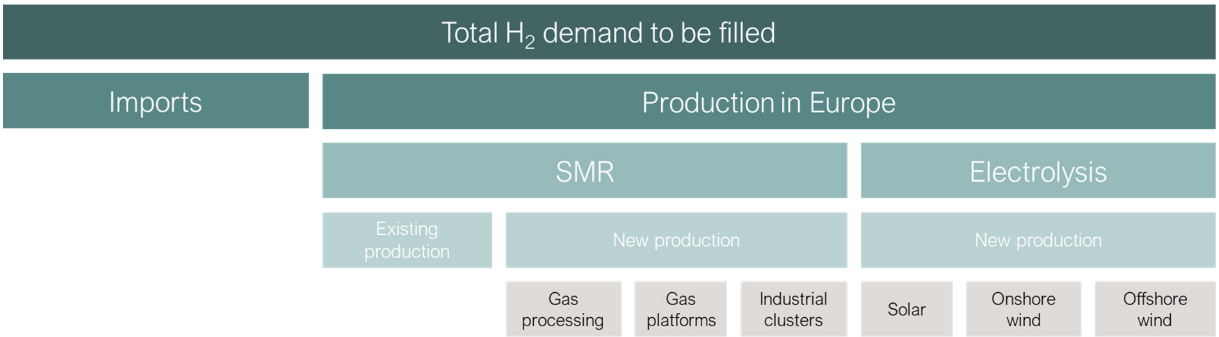
- SMR:
  - Gas processing
  - Gas platforms
  - Industrial clusters
- Electrolysis with renewables:
  - Solar
  - Onshore wind

[11] Fuel Cells and Hydrogen 2 Joint Undertaking, *Hydrogen Roadmap Europe,* 2019

- Offshore wind

These categories are shown in Figure 10. This figure also illustrates the fact that SMR growth comes in addition to existing production capacity[12] and that imports of hydrogen from outside Europe are treated separately. [13] Carbon capture and storage (CCS) is assumed to be applied to the carbon dioxide emissions resulting from new SMR production as well as from the retrofitting of existing SMR production.

Figure 10 – Conceptual elements for predicting production of hydrogen. Alternative growth scenarios for SMR and electrolysis are shown in Figure 9. Grey boxes introduce location dependence that is used for geographical mapping. Box sizes are not to scale.



Source: Carbon Limits

The next stage of the analysis was to break down the SMR and electrolysis growth scenarios from Figure 9 according to the conceptual elements shown in Figure 10. The volume of imports is assumed to be the same in each scenario.

This breakdown is given in Table 5. The amount of hydrogen allocated to each type of production is given in terawatt-hours and was found by analysing the numbers behind Figure 9.

[12] Fuel Cells and Hydrogen 2 Joint Undertaking, *Hydrogen Roadmap Europe,* 2019
[13] Hydrogen Europe, *Hydrogen 2030: The Blueprint,* No date

Table 5 - Hydrogen production (TWh) in 2030 and 2050 according to source for two alternative scenarios; SMR (blue) and electrolysis (green) and sources of information for locations.

Item	Sources	Key parameters	H_2 energy equivalent (TWh)				Comments
			SMR scenario		Electrolysis scenario		
			2030	2050	2030	2050	
Imports	GIE, *LNG Map*, 2019	Maximum output capacity	118	399	118	399	Harbour locations connected to the gas network, e.g. LNG import terminals.
Existing production			-	-	-	-	It was assumed that existing producers would continue to serve their existing clients and will therefore not require additional transport infrastructure
Gas processing	E-PRTR[14]	CO_2 emissions	0	1.2	0	0	-
Gas platforms	E-PRTR[14]	CO_2 emissions	0.1	13	0	0	SMR+CCS directly at the natural gas production site
Industrial clusters	E-PRTR[14]	CO_2 emissions	9	890	0	0	SMR+CCS next to large potential users
Solar	EMODnet[15]; Harmonized global datasets of wind and solar farm locations and power[16]	Installed capacity	18	94	53	352	It was assumed that existing large renewable installations are located in some of the most favorable wind and solar areas and can be a good indication of where future renewable production will be situated
Onshore wind		Installed capacity	37	276	111	1036	
Offshore wind							

Source: Carbon Limits based on Fuel Cells and Hydrogen 2 Joint Undertaking, Hydrogen Roadmap Europe, 2019

[14] European Environment Agency, *European Polutant Release and Transfer Register Regulation*, 2019, https://www.eea.europa.eu/data-and-maps/data/industrial-reporting-under-the-industrial-3
[15] EMODnet, *Human activities – wind farms*, 2021, https://www.emodnet-humanactivities.eu/view-data.php
[16] Dunnett, S. et al., *Harmonised global datasets of wind and solar farm locations and power*, 2020, https://www.nature.com/articles/s41597-020-0469-8 with database available at https://figshare.com/articles/dataset/Harmonised_global_datasets_of_wind_and_solar_farm_locations_and_power/11310269/2

Location of the production – creation of the H_2 production grid

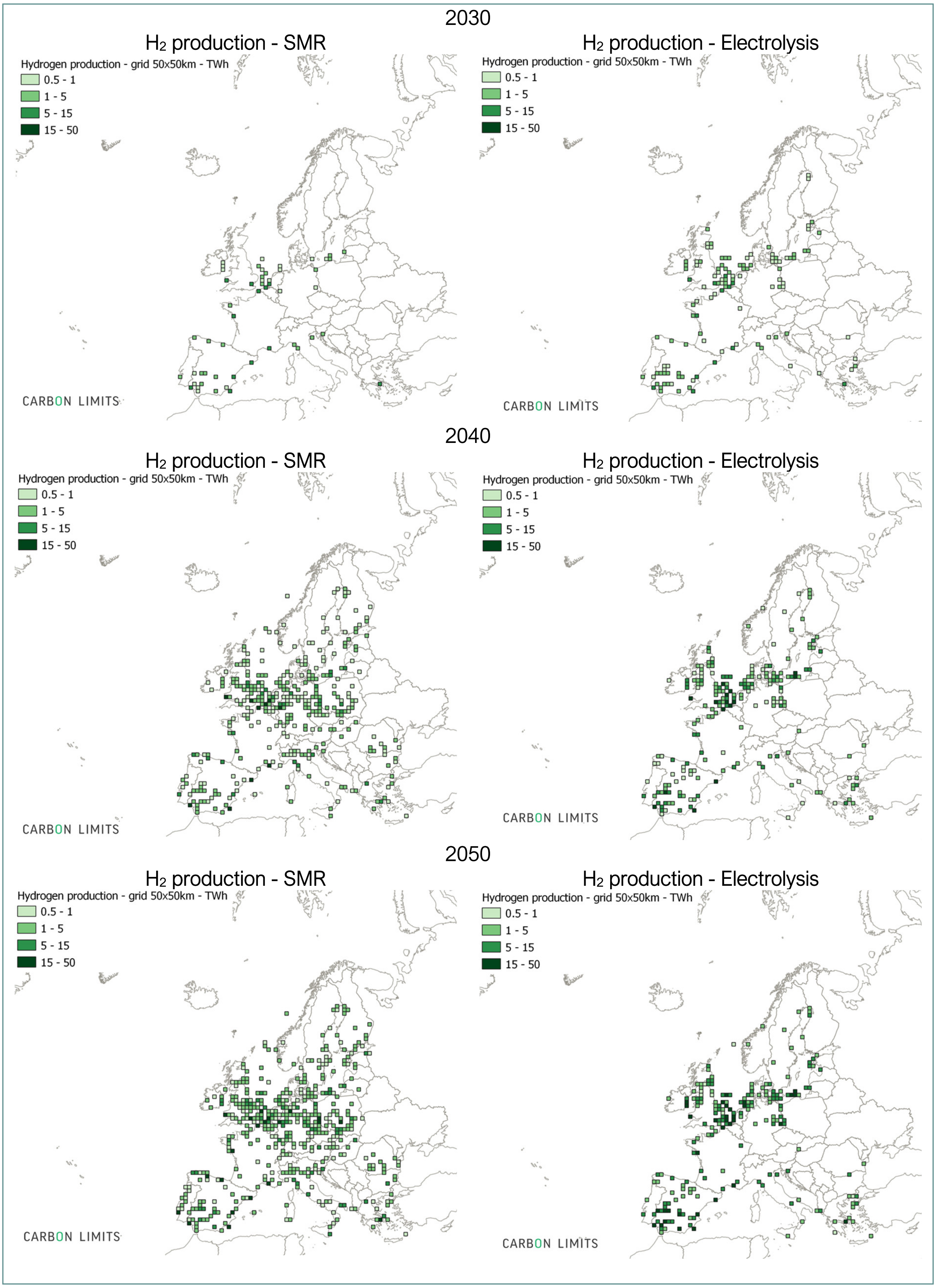
The following assumptions about the future locations of production were used:

- The growth in hydrogen imports shown for both scenarios in Table 5 is assumed to take place at existing LNG terminal locations since they are harbour locations that are connected to the gas network. The infrastructure may not be compatible with hydrogen products, but the geographical locations are relevant.[17]
- The growth in hydrogen production from gas processing, gas platforms and industrial clusters is assumed to take place at existing locations for such facilities and in proportion to their current size.
- The same reasoning was applied to the future growth of green hydrogen in order to predict the production locations. Electrolysis locations from renewable energy are seen to be less dispersed than SMR locations due to the lower number of current areas suitable for large scale renewable deployment (Iberian Peninsula, North Sea and Baltic Sea).

These assumptions were used to determine the amount of hydrogen production in 2030 and 2050 for each data point and these were then upscaled onto a 50x50 km grid according to the methodology presented above. The resulting density maps for hydrogen production are shown in Figure 11.

[17] For more information, see DNV, "Study on the Import of Liquid Renewable Energy: Technology Cost Assessment" for GIE, 2020 – available at https://www.gie.eu/wp-content/uploads/filr/2598/DNV-GL_Study-GLE-Technologies-and-costs-analysis-on-imports-of-liquid-renewable-energy.pdf

Figure 11 – Maps of hydrogen production density by year for SMR and Electrolysis from renewables scenarios. Production density = volume of production facilities within a 50x50 km grid cell.



Source: Carbon Limits analysis

Note that these maps were generated using a systematic approach and may not reflect the precise situation in individual locations.

Hydrogen consumption locations

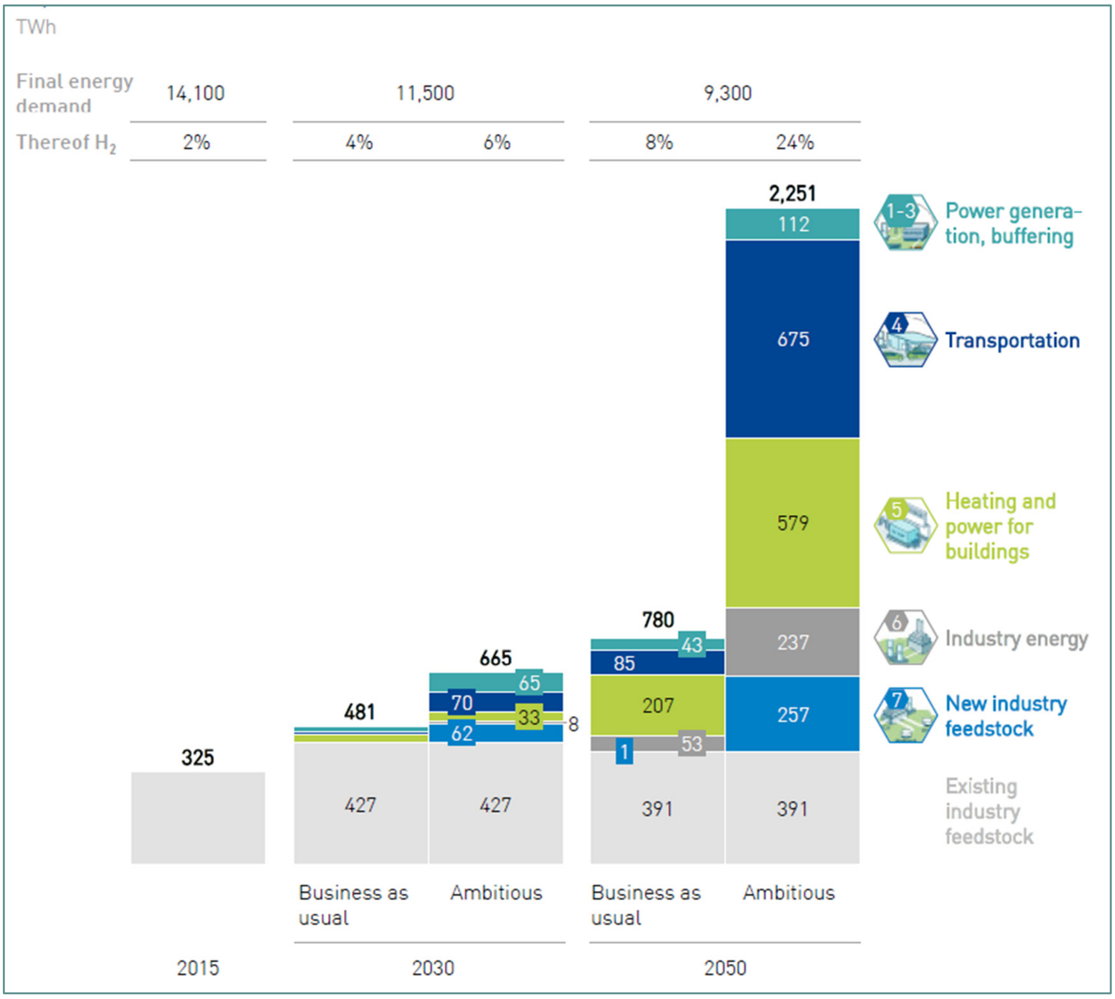
Future consumption has been mapped by analysing the sectors that are expected to make most use of hydrogen and anticipating where their associated facilities will be built. After breaking the consumption forecasts down and allocating the consumptions to the different locations, they are then aggregated up again to create the maps of total consumption shown in Figure 13.

Future consumption of hydrogen

Currently, the main uses for hydrogen in Europe today are oil refining, ammonia production and other industrial uses, such as metallurgy or flat glass production[18]. Additional uses in the future are expected to include reduction of iron ore and as an energy carrier for industry, buildings and transport.

The level of hydrogen use in Europe was 325 TWh (2015 data) and this is expected to grow to between 780 and 2,251 TWh by 2050[19].

Figure 12 - Future hydrogen consumption (the Ambitious scenario was considered for this study)



Source: Fuel Cells and Hydrogen 2 Joint Undertaking, Hydrogen Roadmap Europe, 2019

[18] Hydrogen Europe, *Hydrogen Applications,* no date, https://hydrogeneurope.eu/hydrogen-applications
[19] Fuel Cells and Hydrogen 2 Joint Undertaking, *Hydrogen Roadmap Europe,* 2019

The sectors used in this analysis are based on those from the 2019 study, *Hydrogen Roadmap Europe*[20]*:*

- Existing feedstock uses - Hydrogen is already used in sectors such as oil refining, ammonia and fertilizer production, metal working and glass production. For existing feedstock uses, it was assumed that existing producers would continue to serve their existing clients. No new transport infrastructure would be required to transport hydrogen between existing production and use sites, as it is already in place.
- Industry new feedstock – Iron and steel – hydrogen may be used as alternative reduction agent to coal and combined with CCS to avoid CO_2 emissions[21].
- Industry new feedstock and energy – Other – Multiple industrial uses are feasible including use in industrial processes for ammonia production and refining of petrochemicals[22].
- Power generation, buffering - As hydrogen is an effective energy carrier and can also serve to store energy, power generation and buffering is also cited as a potential application. Energy production facilities can be located in most places, likely close to consumption centres.
- Transportation - Hydrogen has also been deemed an interesting path to reduce CO_2 emissions from the transport sector, whether it be used as fuel for road vehicles, airplanes, rail or ships. In aviation specifically, where electrification is more difficult to achieve, hydrogen is presented as one of the only options in a low-carbon world, mainly through the use of synfuels.
- Building heating and power - In the residential sector, hydrogen, either in its pure form or blended with the natural gas, has been presented as an option to decarbonize natural gas distribution. Some trials of blending hydrogen in the distribution gas stream are currently underway in the UK.

Based on the figures from Hydrogen Roadmap Europe study, the hydrogen consumption has been forecasted for each sector in 2030 and 2050 as shown in Table 6. Future consumption values for the different sectors were adapted from the ambitious scenario presented in Figure 12 based on the current value of key parameters across the sector and narrowed down to a sub-sector level based on these same parameters, where applicable.

[20] Fuel Cells and Hydrogen 2 Joint Undertaking, *Hydrogen Roadmap Europe,* 2019
[21] European Parliamentary Research Service, *The potential of hydrogen for decarbonizing steel production,* 2020
[22] Fuel Cells and Hydrogen 2 Joint Undertaking, *Hydrogen Roadmap Europe,* 2019

Table 6 - Hydrogen consumption (TWh) by sector for years 2030 and 2050 and sources of information for locations.

Item	Sources	Key parameters	Volume of H_2 (TWh)		Comments
			2030	2050	
Existing feedstock uses			-	-	It
Industry new feedstock – Iron and steel	E-PRTR	CO_2 emissions	19	140	H_2 as alternative reduction agent to coal.
Industry new feedstock and energy - Other	E-PRTR	CO_2 emissions	49	354	
Power generation, buffering	-	-	-	-	Can be located where the energy needs are, no specific location has been attributed
Transportation					
Transportation - Airports	Eurostat, National freight and mail air transport by main airports in each reporting country (AVIA_GONA), no date; Eurostat, Air passenger transport by main airports in each reporting country (AVIA_PAOA), no date	Weight transported	9	88	For airports with passenger transport, a passenger was equated to 80 kg
Transportation - Ports	Eurostat, Vessels in main ports by type and size of vessels (mar_tf_qm), no date EMODnet	Large vessel movements	9	90	All vessels above 100,000 tonnes
Transportation - Train stations	Consumer Choice Center, European Railway Station Index 2020, no date	Passengers	0.6	6	
Building heating and power	Eurostat[23] [24]	Populations in large cities in countries with important residential natural consumption Share of natural gas consumption for household Share of natural gas consumption in Europe	25	465	2030: development first for city population below 500,000 + France / Netherlands/ Germany / United Kingdom[25] 2050: all cities / all countries

Source: Carbon Limits analysis

[23] Eurostat, *Population on 1 January by age groups and sex – cities and greater cities – URB_CPOP1,* 2018 data, https://ec.europa.eu/eurostat/databrowser/view/urb_cpop1/default/table?lang=en
[24] Eurostat, *Final energy consumption in households by fuel – T2020_RK210*, 2018 data, https://ec.europa.eu/eurostat/databrowser/view/t2020_rk210/default/table?lang=en
[25] Fuel Cells and Hydrogen 2 Joint Undertaking, *Hydrogen Roadmap Europe,* 2019

Location of the consumption – creation of the H_2 consumption grid

Future locations for hydrogen consumption have been extrapolated from the current location of i) present day consumption, and ii) the present-day location of consumption hubs that belong to the sectors listed above.

The consumption volumes for 2030 and 2050 from Table 6 were distributed by location in proportion to the size of present-day facilities as was done for production volumes. The consumption volumes for 2040 were interpolated in a linear manner from the 2030 and 2050 maps. See Figure 13.

Existing feedstock was considered to be covered by existing production as this is not expected to vary significantly up to 2050. Within industry new feedstock and energy, volumes of H_2 consumption were separated between Iron and Steel facilities and others.

The volumes for power generation and buffering were not attributed to specific locations as it was assumed that such installations could be installed in most locations. It was therefore not relevant, in the context of this study, to specify a location for these.

Within transportation, the volumes of hydrogen consumption were further distributed between the different modes of transport based on their level of fossil fuel consumption within the sector[26]. The key parameters vary per mode of transport. For airports, the weight transported was considered. To extend this parameter to passenger airports as well, it was considered that one passenger could be equated to 80 kg. For ports, the number of large vessel movements[27] in ports, considering vessels above 100,000 tonnes, was used as the key parameter.

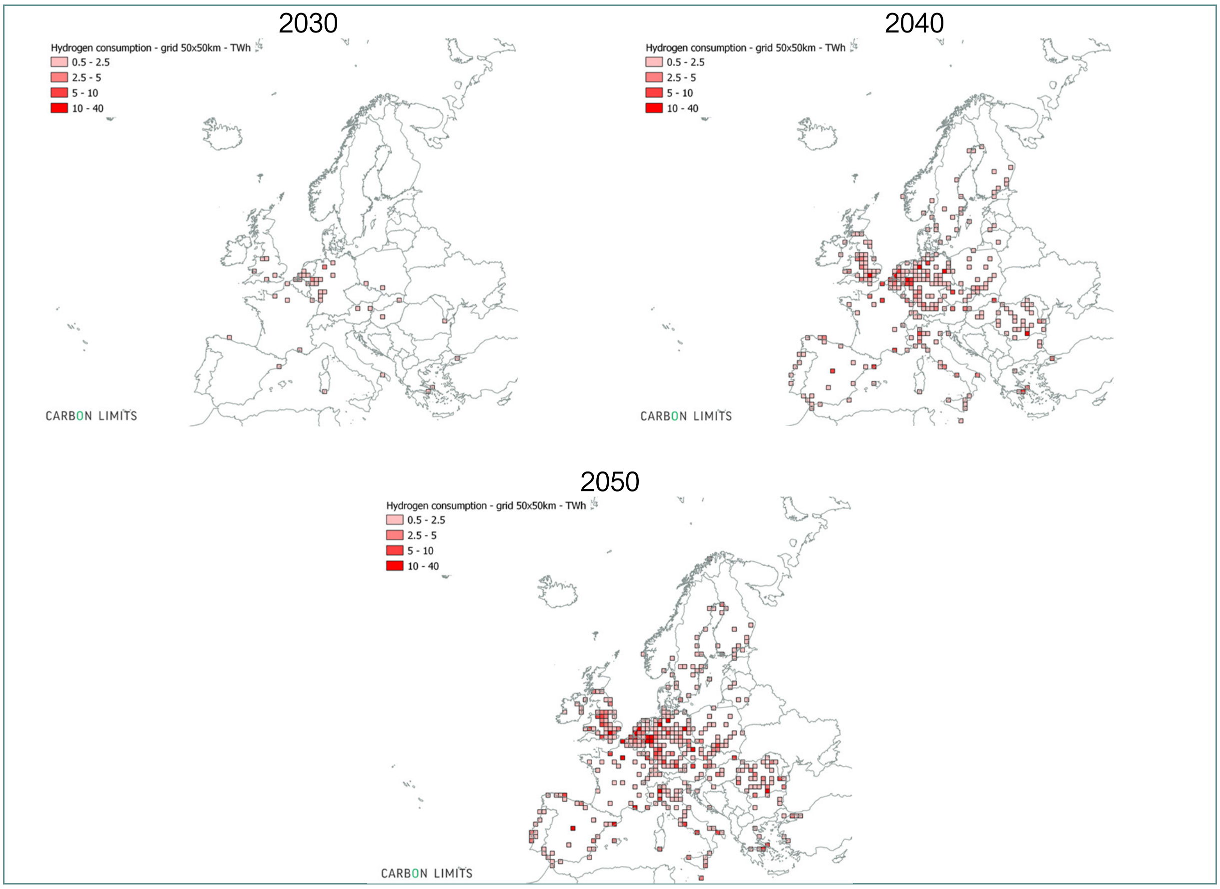
Finally, use of hydrogen in the residential sector was determined by focusing on the countries with high natural gas consumption in the residential sector and the cities within this country that could use hydrogen as a replacement fuel for natural gas. In the *Hydrogen Roadmap Europe* from Fuel Cells and Hydrogen 2 Joint Undertaking, four countries are in the lead for implementing this fuel switch (France / Netherlands/ Germany / United Kingdom) and are the ones considered for 2030. This fuel switch may not be considered in the largest cities first so to spread the H_2 use in 2030 only cities with population below 500,000 inhabitants within the above mentioned 4 countries were considered. For 2050, all cities and countries are taken into account. The parameters considered to spread the H_2 use volumes are the populations, the share of natural gas consumption for household in the country and the share of natural gas consumption in Europe. The estimated volumes and their location were then mapped out based on which a hydrogen consumption density grid was built, to visualize the locations with the highest likelihood of being important hydrogen consumers.

Figure 13 presents the result of the methodology described above. As with hydrogen production, a density map was created based on the localisation of potential users and the potential consumption volume that was estimated for each location, aggregated across a 50x50 km grid.

[26] Eurostat, *Final energy consumption in transport by type of fuel (TEN00126),* 2017, https://ec.europa.eu/eurostat/databrowser/view/ten00126/default/table?lang=en

[27] Eurostat, *Vessels in main ports by type and size of vessels (based on inwards declarations) – quarterly data,* 2019, https://ec.europa.eu/eurostat/databrowser/view/mar_tf_qm/default/table?lang=en

Figure 13 – Maps of hydrogen consumption density by year where consumption density = volume of consumption facilities within a 50x50 km grid cell.



Source: Carbon Limits analysis

Hydrogen storage facilities

Storage facilities will be required as a buffer between supply and demand across a variety of timescales from days to months. The logistics of such storage have not been analysed in detail in the project, but the requirement for such facilities is indispensable, as highlighted by Guidehouse in their analysis "Picturing the value of underground gas storage to the European hydrogen system".[28]

Whilst small storage facilities may be constructed independently of geography, large scale storage facilities are anticipated to rely on access to salt formations below the ground[29]. Salt is extracted from the salt formations in some areas by dissolution mining and the resulting caverns in the rock are sufficiently inert that they can store hydrogen in a safe manner. Depleted fields and aquifers are the next best large-scale solutions for hydrogen storage.

These types of storage have been used for decades for gas storage and could be repurposed for hydrogen storage (also in the form of blending H_2 with methane). As highlighted by Guidehouse[30], the development time of a hydrogen storage site can be from pre-feasibility to H_2 injection test, to operation

[28] Guidehouse for GIE, Picturing the value of underground gas storage to the European hydrogen system, June 2021, available at https://www.gie.eu/wp-content/uploads/filr/3517/Picturing%20the%20value%20of%20gas%20storage%20to%20the%20European%20hydrogen%20system_FINAL_140621.pdf
[29] Hydrogen potential in salt caverns in Europe – Caglayan et al (2020)
[30] Guidehouse for GIE, Picturing the value of underground gas storage to the European hydrogen system, June 2021

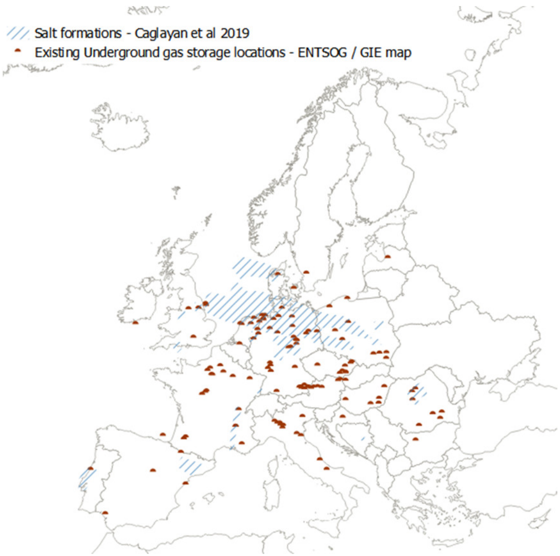
between 1 and 7 years (when repurposing an existing gas storage) and between 3 and 10 years (for a new storage site).

The potential hydrogen storage locations were identified, but the capacities of these storage locations have not been calculated.[31] In Figure 14, the potential areas of interest for hydrogen storage sites are mapped out.

Table 7 - Hydrogen storage options – sources of information

Item	Sources
Existing UGS	ENTSOG / GIE System Development map 2019 -2020 Guidehouse for GIE, Picturing the value of underground gas storage to the European hydrogen system, June 2021
Salt formations	Hydrogen potential in salt caverns in Europe – Caglayan et al (2019)[29]

Figure 14 - Location of potential hydrogen storage in Europe



Source: Carbon Limits based on Caglayan et al 2019 and ENTSOG / GIE map

Storage of hydrogen in repurposed LNG tanks was also considered but was deemed unlikely due to the differences in technical specifications.[32] LNG terminals are considered as locations for imports of hydrogen (see above).

Now that the most interesting areas for H_2 production, consumption and storage have been identified, the same type of exercise was carried out for identifying most interesting areas for CO_2 sources and sinks.

[31] Data were collected for assessing H_2 storage capacity. Only 25 UGS had however communicated their qualitative assessment for H_2 storage and only 11 had provided sufficient data for the Re-stream to calculate the capacity.
[32] Interview of DNV experts

4.3 Carbon dioxide facility mapping

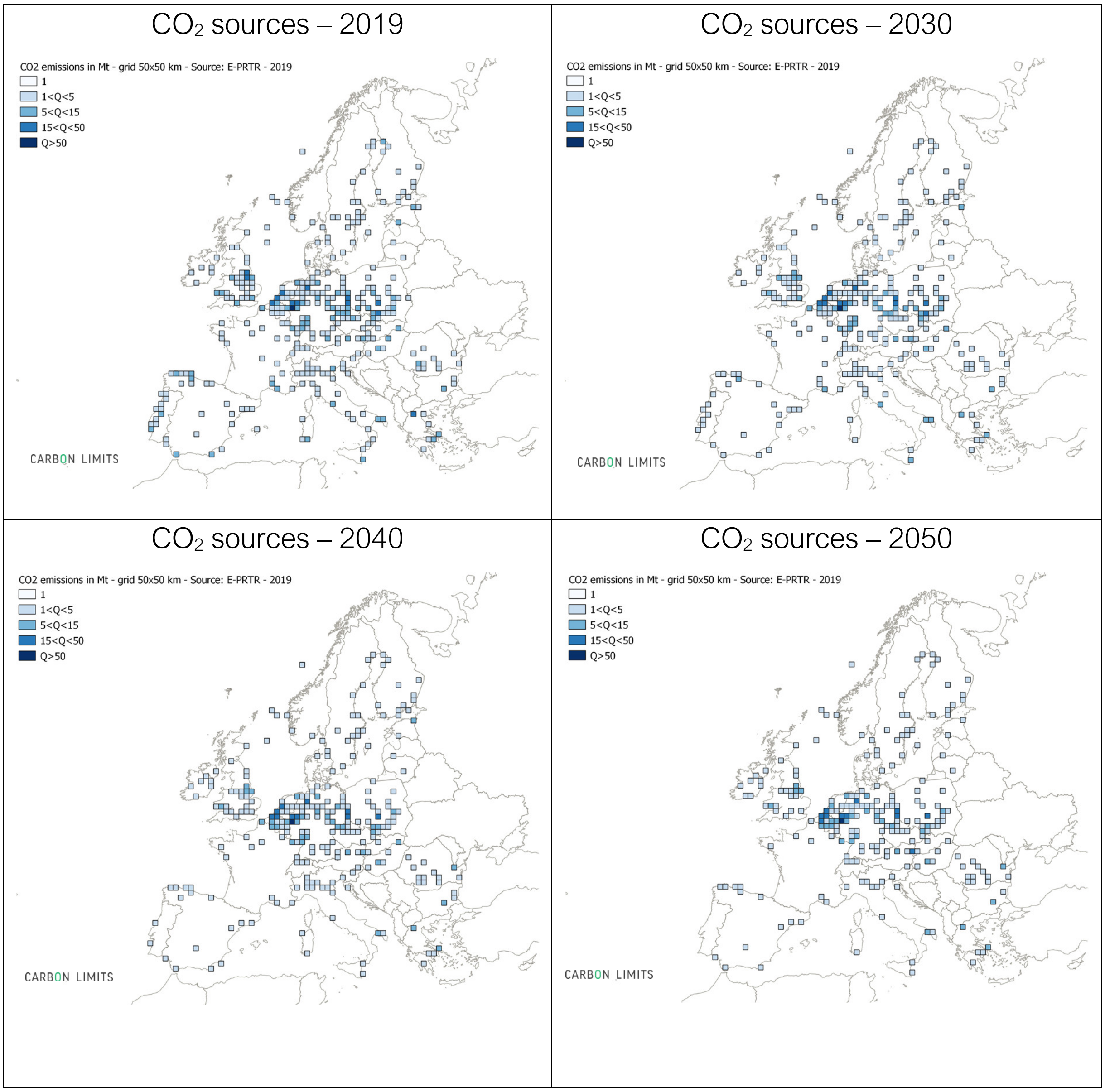
Carbon capture facilities

The geographical distribution of carbon dioxide emissions over time were mapped out using a similar methodology to hydrogen production and consumption. The location of emissions was based on the current location of all facilities registered in the European Pollutant Release and Transfer Register (E-PRTR). Emissions are divided into sectors and the rate of emissions reductions per sector were estimated based on a review of industry roadmaps (cement[33], ammonia[34], iron and steel[35] and petrochemicals[36]) or European level forecasts[37] where industry specific data was unavailable.

Sectoral emission forecasts were then aggregated up to provide maps of total carbon dioxide emissions by location on the coarse grid for the years 2030, 2040 and 2050. Maps for each year are shown in Figure 15.

[33] CEMBUREAU, Cementing the European Green Deal, May 2020, https://cembureau.eu/media/1948/cembureau-2050-roadmap_final-version_web.pdf
[34] Material Economics, Industrial Transformation 2050 - Pathways to Net-Zero Emissions from EU Heavy Circular economy scenario, 2019
[35] Eurofer, Low carbon Roadmap – Pathways to a CO2-neutral European steel industry, 2019
[36] Material Economics, Industrial Transformation 2050 - Pathways to Net-Zero Emissions from EU Heavy Circular economy scenario, 2019
[37] EEA, Member States' greenhouse gas (GHG) emission projections, 2020, https://www.eea.europa.eu/data-and-maps/data/greenhouse-gas-emission-projections-for-7

Figure 15 - CO_2 emission sources - density grid 50x50 km - 2019 / 2030 / 2040 / 2050



Source: Carbon Limits analysis

Carbon shipping hubs

The location of industrial ports is expected to play an important role in the distribution of carbon dioxide infrastructure since they may serve as hubs to gather emissions from dispersed capture sites before transfer by ship or pipeline. Port locations are shown in Figure 16.

Carbon storage sites

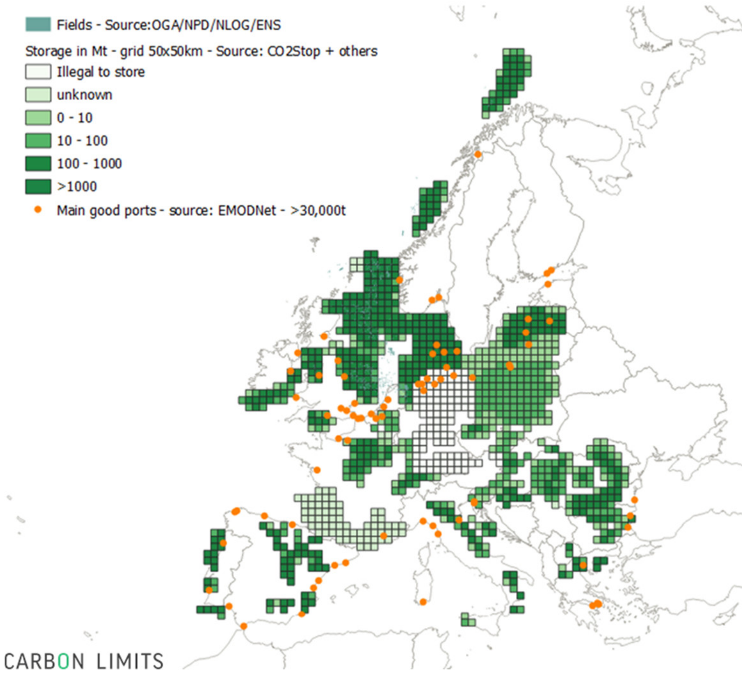
The only form of carbon dioxide storage considered in this study is permanent storage in geological formations, either saline aquifers or depleted hydrocarbon fields.

The geographical distribution of these formations has already been mapped in Europe and only minor changes are expected to occur as newly depleted hydrocarbon fields become available and drilling campaigns provide new information. Sources of information are given in Table 8 and the map of potential storage areas is shown in Figure 16.

Table 8 - Data sources for mapping carbon dioxide facilities.

Item	Sources	Comments
CO_2 storage – saline aquifers	CO_2Stop database[38] / GeoCapacity FP6 / COMET FP7[39] / CO_2Stored UK[40] / GCCSI CO2Re[41] / Norwegian CO_2 Storage Atlas[42]	
CO_2 storage – depleted fields	Location of the fields available NPD[43]/ RWS[44]/ OGA[45]	
CO_2 storage – terminals/clusters	EMODNet[46]	Identification of ports/clusters of emissions + dedicated terminals (e.g. Kollsnes) Main goods ports >30,000 t/y Only location was identified

Figure 16 - CO_2 storage locations - density grid 50x50 km and ports



Source: Carbon Limits analysis

In section 3.2, the results of the initial screening for reuse were presented while in this section, the most interesting areas for future hydrogen production, use and storage and for CO_2 sources and sinks were identified. The objective of the following section is to present the business opportunities for reuse of the oil and gas infrastructure taking into account the results of the previous sections.

38 Available at https://setis.ec.europa.eu/european-co2-storage-database
39 COMET, https://cordis.europa.eu/project/rcn/93469/reporting/en
40 Bentham et al,2014. CO2 STORage Evaluation Database (CO2 Stored). The UK's online storage atlas.
41 Available at https://co2re.co/StorageData
42 Halland et al, CO2 Storage atlas
43 Available at https://www.npd.no/en/about-us/information-services/open-data/
44 Available at https://www.nlog.nl/en/files-interactive-map
45 Available at https://data-ogauthority.opendata.arcgis.com/datasets/oga-offshore-fields-wgs84/explore?location=56.172800%2C-0.567550%2C5.99
46 Available at https://emodnet.eu/en/human-activities

5. Business opportunities and selection of case studies

In this section, the potential reusable pipelines are overlaid with the high probability locations of CO_2 sources and sinks and H_2 production, consumption and storage. The objective of this section is to assess a minimum length of reusable pipelines with obvious business opportunities and to select case studies to be further assessed from an economic standpoint. For the selected case studies, new built options to which the reused pipelines are compared are described.

5.1 Business opportunities

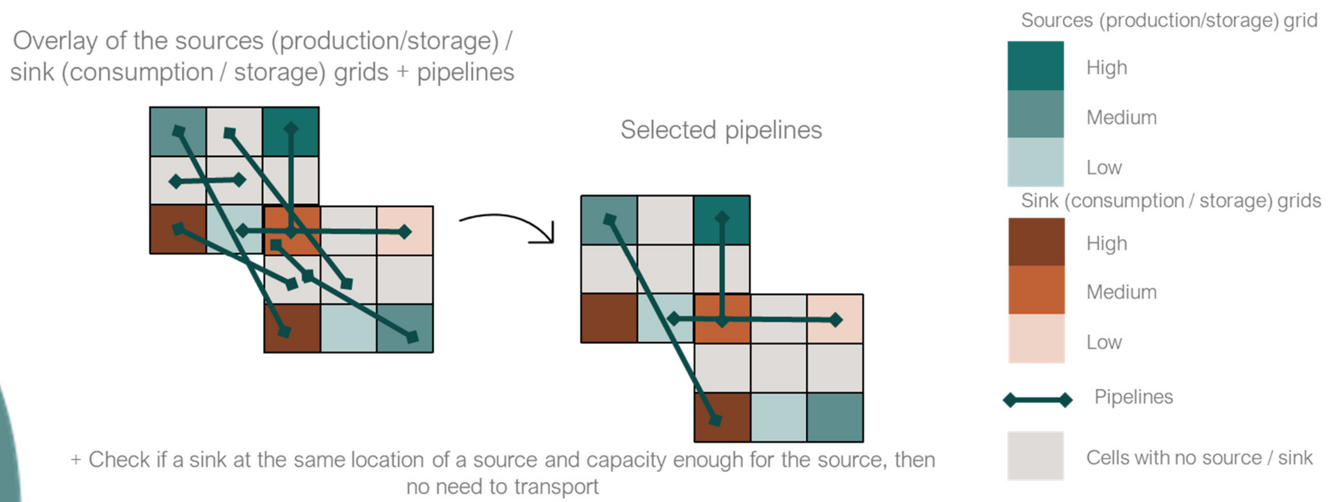
Approach

In order to identify case studies for further economic assessment, an automated process was undertaken:

- The reusable pipelines were overlaid with the locations of the sources (production/storage) / sink (consumption / storage) grids.
- The pipelines linking a source location (end or start of a pipeline section) to a sink location (end or start of a pipeline section) were then selected.
- In an automated way, the need to transport was assessed:
  - If a sink is at the same location of a source and if the sink capacity is enough for the source, then there is no need to transport the fluid.

There are however some limitations to the implemented automatic approach as it does not account for the network perspective nor for the fact that only part of the pipelines could be reused. Some visual observations were carried out and indications from the operators taken into account to add the network perspective. This approach, illustrated in Figure 17, allowed to identify a minimum length of reusable pipelines and several case studies.

Figure 17 - Illustration of the approach carried out to identify case studies



Source: Carbon Limits

Results for CO_2

At least around 70% of the existing offshore pipeline length is relevant for CO_2 transport as many of the long pipelines are linking harbours to CO_2 storage locations. Of the 140 offshore pipeline sections detailed by the operators, around 50 pipeline sections were identified as potential case studies / part of case studies.

Regarding onshore pipelines, a minimum of 20% of the pipeline length shows some business opportunities linking sources to sinks (harbours or onshore storage sites). Of the 570 onshore pipeline sections detailed by the operators, 100 pipeline sections were identified as potential case studies / part of case studies. It is very likely that this length would grow significantly if only part of the pipelines were to be reused or if pipeline connections had been considered. Note that the methodology does not account for the date of availability of the pipeline for other use as this data was generally not always available in the dataset.

Table 9 – Business opportunities - CO_2 - results from the demand/production locational assumptions and source-sink matching - minimum reusable pipeline length for pipelines in cat. A and B (A= pipelines reusable considering the current state of knowledge/standards, B= pipelines that would require more testing and/or update of standards to be reusable)

Business opportunities	Offshore pipelines		Onshore gas pipelines		Onshore oil/product pipelines	
	If dense phase	If gas phase	If dense phase	If gas phase	If dense phase	If gas phase
Average CO_2 transport capacity ($MtCO_2$/y) cat. A+B with identified business opportunities	31	3	17	3	2.3	0.9
Minimum reusable pipeline length (km) cat. A pipelines	5,740	12,000	0	5,950	50	3,560
Minimum reusable pipeline length (km) cat. B pipelines	6,260	/	950	/	950	/
Remaining length with unidentified business opportunities linked to approach or no business opportunity but reusable in cat. A or B (km)	4,370		3,660	21,650	5,290	9,340
Total pipeline length assessed (km)	16,370		27,600		12,900	

Note: the assumptions made for the transport capacity are given in Table 1. The capacities were calculated for individual pipeline sections.
Source: Re-Stream team analysis

Results for H_2

The same analysis was carried out for hydrogen, the SMR/ATR production scenario giving a higher degree of obvious business opportunities compared to the electrolysis one as the SMR/ATR production locations are linked to the current gas infrastructure.

The followed approach identifying business opportunities shows a minimum reusable offshore pipeline length for hydrogen of 2% to 25% depending on the production scenario with up to 20 case studies identified.

With regards to onshore, based on the demand/production locational assumptions, the initial technical screening and even under the detailed conservative approach, the minimum reusable pipeline length for hydrogen is 20% to 30% depending on the hydrogen production scenario with up to 130 pipeline sections looking interesting from a business perspective. Note that the methodology does not account for the date of availability of the pipeline for other use as this data was not always available in the dataset.

As for CO_2, it is very likely that this length would grow significantly if only part of the pipelines were to be reused or if pipeline connections, the security of supply and the benefits of an interconnected market had been considered. [47] According to the operators, the EU network is so well meshed that current infrastructures are likely to be enough to connect production with demand with only the last miles that would need to be added.

Table 10 – Business opportunities - summary for H_2 – results from the demand/production locational assumptions and source-sink matching - minimum reusable pipeline length for pipelines in category A and B (A= pipelines reusable considering the current state of knowledge/standards, B= pipelines that would require more testing and/or update of standards to be reusable)

Business opportunities Electrolysis scenario	Offshore pipelines	Onshore gas pipelines	Onshore oil/product pipelines
Average H_2 transport capacity (TWh/y) cat. A+B with identified business opportunities	8	29	6
Minimum reusable pipeline length (km) cat. A pipelines	310	4,120	2,710
Minimum reusable pipeline length (km) cat. B pipelines	-	1,810	560
Remaining length with unidentified business opportunities linked to approach or no business opportunity but reusable in cat. A or B (km)	16,060	22,870	9,630
Total pipeline length assessed (km)	16,370	28,800	12,900

Business opportunities SMR/ATR scenario	Offshore pipelines	Onshore gas pipelines	Onshore oil/product pipelines
Average H_2 transport capacity (TWh/y) cat. A+B with identified business opportunities	13	28	7
Minimum reusable pipeline length (km) cat. A pipelines	3,910	6,120	4,680
Minimum reusable pipeline length (km) cat. B pipelines	280	2,240	580
Remaining length with unidentified business opportunities linked to approach or no business opportunity but reusable in cat. A or B (km)	12,180	20,440	7,640
Total pipeline length assessed (km)	16,370	28,800	12,900

Note: the assumptions made for the transport capacity are given in Table 1. The capacities were calculated for individual pipeline sections.
Source: Re-Stream team analysis

[47] Indeed, several producers connected to several consumers is a better model for the development of a market and to ensure security of supply.

5.2 Selection of case studies

Up to 6 cases were to be selected for a more detailed technical assessment and an economic analysis. In order to select those cases, some of the resulting cases from the business opportunity analysis were presented to the steering group and a voting process among the group was undertaken.

The initial idea was to have six representative cases, 3 for CO_2 and 3 for H_2.

For the CO_2 cases to be representative, the 3 following classes of cases were presented:

- Offshore dense phase transport to saline aquifer or depleted field
- Onshore gas phase transport to harbour
- Onshore gas phase transport to onshore storage

The cases from which to choose from in the different classes varied in type of pipes (oil or gas), capacity, country, CO_2 source type, distance and connections (within a country or cross-border).

For the H_2 cases to be representative, the 2 following classes of cases were presented:

- Offshore transport from wind farm to H_2 consumer
- Onshore transport from solar farm or wind farm / LNG terminal/Harbour to H_2 consumer (2 cases)

The cases from which to choose from in the different classes varied in type of pipes (oil or gas), capacity, country, H_2 consumer type, H_2 producer type, distance and connections (within a country or cross-border).

Several cases per classes were presented to the steering group (available in appendix 9.1) and after the voting process, the following cases were chosen.

Table 11 - CO_2 selected cases

Class of case	Offshore dense phase transport to saline aquifer or depleted field	Onshore gas phase transport to harbour	Onshore gas phase transport to onshore storage
Case name	1 - Fulmar - St Fergus (UK)	2 – Paris – Port Jérôme (FR)	3 - Setúbal – Leiria (PT)
Current operator	Shell	Trapil	REN
Current Fluid transported	Gas	Oil	Gas
Dimension (D/L)	20” – 289 km	20” – 170 km	28” - 68 km
CO_2 source	A possible ACORN project extension	Around Paris Waste to energy Cement Other 1.6 $MtCO_2$/y	Power plants 1.2 $MtCO_2$/y
CO_2 storage - Depleted field / Deep Saline aquifers	Several formations including Balder – theoretical storage capacity: 3.3 $GtCO_2$	Port Jérôme	Lusitanian – 0.1 $GtCO_2$
Location			

Note: Case 3 - The Portuguese gas network is set to be the future H_2 national backbone, in accordance with the national energy policy. Any evaluation for CO_2 management purposes is at this stage only for evaluation purpose.
Source: Re-Stream team analysis

Table 12 - H_2 selected cases

Class of case	Offshore transport from wind farm to H_2 consumer	Onshore transport from solar farm or wind farm / LNG terminal/Harbour to H_2 consumer	Onshore transport from solar farm or wind farm / LNG terminal/Harbour to H_2 consumer
Case name	4 – P15 –D – Maasvlakte (NL)	5 – Almodovar – Merida (ES)	6 – Feeder 13 (UK)
Current operator	TAQA Energy	Exolum	National Grid
Current Fluid transported	Gas	Product	Gas
Dimension (D/L)	26" – 40 km	8 5/8" - 215 km	18" / 42" – 240 km
H_2 producer	Wind farms: Hollandse Kust Zuid Holland III – IV / Hollandse Kust Zuid Holland I - II OWF Luchterduinen – 8.8 TWh/y	Solar – 4 TWh	St Fergus – 1.4 TWh/y
H_2 consumer	Rotterdam / to be distributed from there	Industrial clusters: Refinery / Fertilizer	Edinburgh area Airport Industries 1.1 TWh/y
Location			

Source: Re-Stream team analysis

For each of the selected cases, the design of a new build pipeline was carried out to have the background data to perform the economic assessment.

5.3 Definition of scenarios and design of new built pipelines for CO_2 cases

Assumptions for capacity and design of new build (new pipeline or new segments)

The following general assumptions were used for the different cases:

- For each pipeline case, up to 4 scenarios were considered:
  - Re-use of existing pipeline with transport capacity based on CO_2 source limitation
  - New built pipeline with transport capacity based on CO_2 source limitation
  - Re-use of existing pipeline with transport capacity based on existing pipeline limitation
  - New built pipeline with transport capacity based on existing pipeline limitation

  The reason for doing the comparison for both the CO_2 source capacity and the existing pipeline capacity is to cover the range of uncertainties in the CO_2 source forecast. When the CO_2 source capacity and existing pipeline capacity are similar, no distinction is made in the scenarios.

- As the inlet/outlet locations of the pipelines do not necessarily exactly match the source/storage locations, additional segments were added for this purpose (5 to 35km additional segments).
- It is assumed that no intermediate compression or pumping stations are needed along the pipeline route.

The assumptions made for the transport capacity calculations are indicated in Table 13.

Table 13 – Assumptions for CO_2 capacity calculations

Parameter	Gas phase transport	Dense phase transport
Maximum inlet pressure	Max. 40 bar (away from dew point curve).	Up to current pipeline MAOP
Minimum outlet pressure	20 bar (assumed)	80 bar (away from bubble point curve)
Internal roughness	50 microns if no internal flow coating 15 microns if internal flow coating (assumed to be compatible with CO_2 transport)[3]	
Velocity limitation	10 m/s [1]	5 m/s [1]
Elevation profile	When data available	
Inlet cmpressor/pump	Calculation of compressor duty (MW) [2]	Calculation of pump duty (MW) [2]

[1] Not governing for the cases studies
[2] 20 bar assumed upstream compressor/pump
[3] See chapter 7 for potential challenges with internal flow coating

For the design of new pipelines, the diameter was selected based on the hydraulic simulations (performed with the flow/process software UniSim).

For the new additional small segments connecting to the existing pipeline, the same diameter as the existing line was used for piggability purpose (unless there was a non-negligible cost benefit in changing).

The wall thickness is calculated based on pressure containment criteria in ASME B31.8. The same material as the existing line was selected.

Results for capacity and design of new build (new pipeline or new segments)

The results for the design of the new built pipelines and new segments along with the transport capacities are given in:

- Table 14 for Case 1 – Fulmar - St Fergus (UK) (CO_2)
- Table 15 for Case 2 – Paris – Port Jérôme (FR) (CO_2)
- Table 16 for Case 3 – Setúbal – Leiria (PT) (CO_2)

The results are used as input to the economic assessment in section 6.

Table 14 – Design results for Case 1 – Fulmar - St Fergus (UK) (CO_2) - dense phase

Parameter	1 - Fulmar - St Fergus (UK)	
Scenario	**Reuse**, based on pipeline capacity	**New build,** based on pipeline capacity
Pipeline Length (km)	289.4	289.4
Dimension OD/WT (inch/mm)	20'' OD	20'' OD / 15.8mm WT
Extra segment length (km)	5	5
Extra segment dimension (inch/mm)	20'' OD, 15.8mm WT	20'' OD, 15.8mm WT
Capacity ($MtCO_2$/yr)	**8.9**	**8.9**
Inlet pressure (bar)	172.4	172.4
Outlet pressure (bar)	80	80
New steel weight (t)	**960**	**56 500**
Pump/compressor duty (MW)	**5 MW (pump)**	**5 MW (pump)**

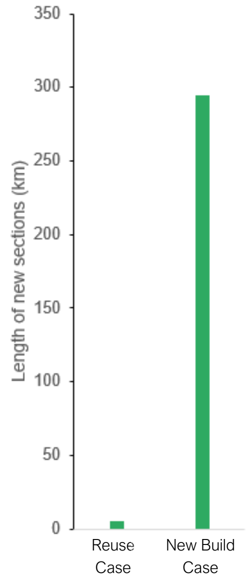


Table 15 – Design results for Case 2 – Paris – Port Jérôme (FR) (CO_2) - gas phase

Parameter	2 – Paris – Port Jérôme (FR)	
Scenario	**Reuse**, based on pipeline capacity	**New build**, based on pipeline capacity
Pipeline Length (km)	159	159
Dimension OD/WT (inch/mm)	20'' OD	20'' OD / 4.4mm WT
Extra segment length (km)	25	25
Extra segment dimension (inch/mm)	20'' OD / 4.4mm WT	20'' OD / 4.4mm WT
Capacity (Mt CO_2/yr)	**1.5**	**1.5**
Inlet pressure (bar)	40	40
Outlet pressure (bar)	20	20
New steel weight (t)	**1 350**	**9 980**
Pump/compressor duty (MW)	**2.3 MW (compressor)**	**2.3 MW (compressor)**

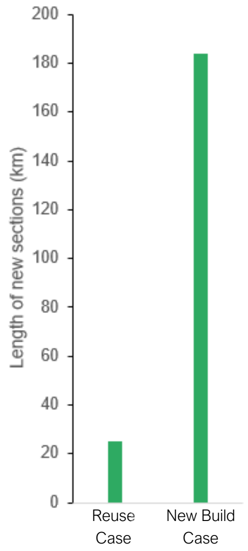
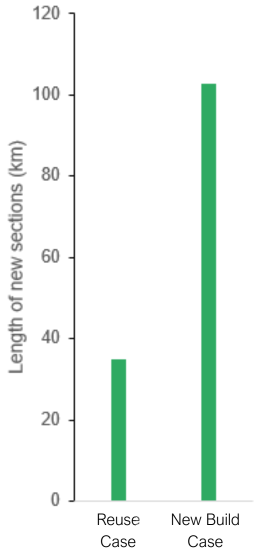


Table 16 – Design results for Case 3 – Setúbal – Leiria (PT) (CO_2) - gas phase

Parameter	3 - Setúbal – Leiria (PT)			
Scenario	**Reuse**, based on source capacity	**New build**, based on source capacity	**Reuse**, based on pipeline capacity	**New build**, based on pipeline capacity
Pipeline Length (km)	67.9	67.9	67.9	67.9
Dimension OD/WT (inch/mm)	28'' OD	16'' OD [2] / 3.8mm WT	28'' OD	28'' OD / 5.8mm WT
Extra segment length (km)	35	35	35	35
Extra segment dimension (inch/mm)	16'' OD / 3.8 mm WT	16'' OD / 3.8 mm WT	28'' OD / 5.8mm WT	28'' OD / 5.8mm WT
Capacity (Mt CO_2/yr)	**1.2**	**1.2**	**5.2**	**5.2**
Inlet pressure (bar)	22 [1]	40	40	40
Outlet pressure (bar)	20	20	20	20
New steel weight (t)	**720**	**3 900**	**3 500**	**10 400**
Pump/compressor duty (MW)	**0.7 MW (compressor)**	**1.9 MW (compressor)**	**8.1 MW (compressor)**	**8.1 MW (compressor)**



Note 1: When reusing the existing pipeline but with a transport capacity limited to the source capacity, the required inlet pressure is lower as compared to the case based on the existing pipeline capacity.
Note 2: When the design is based on the source capacity, a smaller pipeline diameter can be used (compared to the existing pipeline).

Assumptions for capacity and design of new build (new pipeline or new segments)

The same general assumptions used for the CO_2 cases were used for the H_2 cases, i.e.

- up to 4 scenarios per pipeline case (Re-use, New build, based on source capacity or based on existing pipeline capacity),
- additional segments added to match the exact locations of producers/consumers,
- no intermediate compression along the way.

The assumptions made for the transport capacity calculations are indicated in Table 17.

Table 17 – Assumptions for H_2 capacity calculations

Parameter	Gas phase transport
Inlet pressure	*New max. MAOP calculated based on prescriptive method A in ASME B31.12 for hydrogen pipeline. *Actual selected inlet pressure will also depend on required capacity and velocity limitation
Outlet pressure	20 bar (assumed)
Internal roughness	50 microns if no internal flow coating 15 microns if internal flow coating
Velocity limitation	40 m/s (limit considered conservative and can be challenged)
Elevation profile	When data available
Inlet Compressor	Calculation of compressor duty (MW) [1]

[1] 20 bar assumed upstream compressor

For the design of the new pipelines, the diameter was selected based on the hydraulic simulations (performed with the flow/process software UniSim).

The wall thickness is calculated based on pressure containment criteria in ASME B31-12.

For the material, X52 steel was selected for the new pipelines and additional segments.

Results for capacity and design of new build (new pipeline or new segments)

The results for the design of the new built pipelines and new segments along with the transport capacities are given in the table below and will be used as input to the economic assessment in section 6:

- Table 18 for Case 4 – P15 –D – Maasvlakte (NL) (H_2)
- Table 19 for Case 5 – Almodovar – Merida (ES) (H_2)
- Table 20 for Case 6 – Feeder 13 (UK) (H_2)

Table 18 – Design results for Case 4 – P15 –D – Maasvlakte (NL) (H_2)

Parameter	4 – P15 –D – Maasvlakte (NL)			
Scenario	**Reuse**, based on source capacity	**New build**, based on source capacity	**Reuse**, based on pipeline capacity	**New build**, based on pipeline capacity
Pipeline Length (km)	40.1	40.1	40.1	40.1
Dimension OD/WT (inch/mm)	26'' OD	16'' OD/ 4.2mm WT	26'' OD	26'' OD/ 6.1mm WT
Extra segment length (km)	5	5	5	5
Extra segment dimension (inch/mm)	26'' OD/4.5mmWT	16'' OD/ 4.2mm WT	26'' OD/ 6.1mm WT	26'' OD/ 6.1mm WT
Capacity (TWh/yr)	**8.8**	**8.8**	**22.1**	**22.1**
Inlet pressure (bar)	22.5	34	30	30
Outlet pressure (bar)	20	20	20	20
New steel weight (t)	**360**	**1 900**	**490**	**4 400**
Compressor duty (MW)	**0.65**	**4.6**	**9.6**	**9.6**

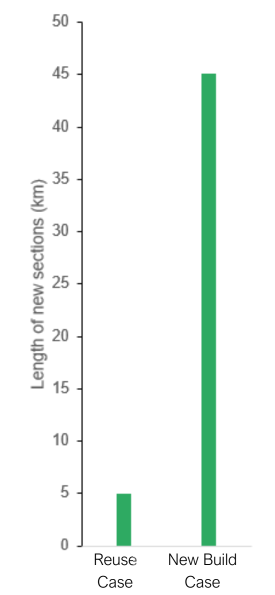


Table 19 – Design results for Case 2 – Almodovar – Merida (ES) (H_2)

Parameter	5 – Almodovar – Merida (ES)			
Scenario	**Reuse**, based on source capacity	**New build**, based on source capacity	**Reuse**, based on pipeline capacity	**New build**, based on pipeline capacity
Pipeline Length (km)	215	215	215	215
Dimension OD/WT (inch/mm)	8.6'' OD	6'' OD / 3.1mm WT	8.6'' OD	8.6'' OD / 5.6mm WT
Extra segment length (km)	10	10	10	10
Extra segment dimension (inch/mm)	8.6'' OD / 2.3mm WT	6'' OD / 3.1mm WT	8.6'' OD / 5.6mm WT	8.6'' OD / 5.6mm WT
Capacity (TWh/yr)	**0.7**	**0.7**	**2.3**	**2.3**
Inlet pressure (bar)	34.4	65	93.3	93.5
Outlet pressure (bar)	20	20	20	20
New steel weight (t)	**120**	**2 600**	**290**	**6 600**
Compressor duty (MW)	**0.4**	**1**	**4.7**	**4.7**

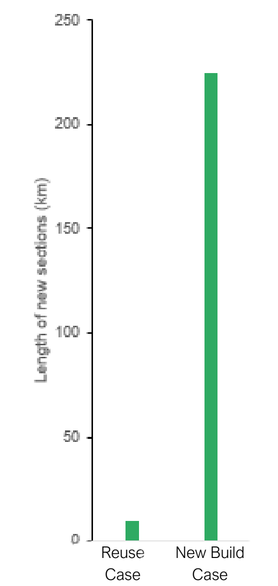
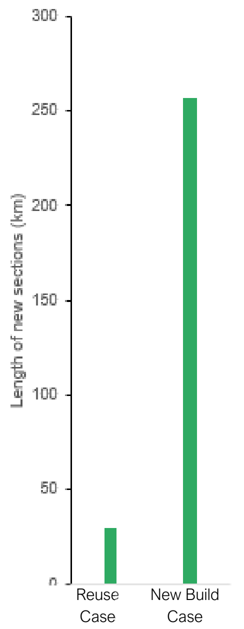


Table 20 – Design results for Case 3 – Feeder 13 (UK) (H_2)

Parameter	6 – Feeder 13 (UK)			
Scenario	Reuse, based on source capacity	New build, based on source capacity	Reuse, based on pipeline capacity	New build, based on pipeline capacity
Pipeline Length (km)	237.3	237.3	237.3	237.3
Dimension OD/WT (inch/mm)	18.5'' / 42.5'' OD	8'' OD / 3.3mm WT	18.5'' / 42.5'' OD	18.5'' OD/9.6mm WT
Extra segment length (km)	30	30	30	30
Extra segment dimension (inch/mm)	8'' OD / 2.0mm WT	8'' OD / 3.3mm WT	8'' OD / 5.7mm WT	18.5'' OD/9.6mm WT
Capacity (TWh/yr)	**1.1**	**1.1**	**12.5**	**12.5**
Inlet pressure (bar)	21	52	40	66.8
Outlet pressure (bar)	20	20	20	20
New steel weight (t)	**200**	**4 400**	**850**	**29 100**
Compressor duty (MW)	**0.080**	**1.200**	**9.7**	**18.3**



The results of the design are used in the next section of the report for the economic assessment.

Box 2 : Compressor reuse

For transport of 100% H_2, the reuse potential of the compressors and drives will be limited by the following aspects:

- Necessity to check the component suitability (embrittlement, leakage, efficiency, need for restaging) when switching to H_2.
  - For piston compressor: drastic reduction in capacity compared to natural gas (factor of 3), and higher compressor power required (reduced efficiency)
  - For centrifugal compressor: challenges even with substantial reduction in pipeline pressure / low capacity (significant restaging of compressor, difficulty to maintain required head).
- Specificities of each compressor stations that cannot be accounted for

Based on this, it has been assumed that new compressors will be needed, i.e. the cost comparison of re-use versus new-build in section 6 is limited to the pipelines for the CAPEX.

Note that for initial stages with potential blends of hydrogen with natural gas, some compressors could be re-used (for 10-15% blends, there would be limited changes for some compressors, but increased speed and/or reduced performance).

Source: interview with technology provider in 2021

6. Economic Assessment

In this part of the report, an economic assessment of the selected cases is performed. The methodology used to assess the cases and the results are documented in the following sections. Then the assessment results are presented. Finally, results are synthesized and discussed.

6.1 System boundary

The assessment includes the transport stage of the gas. The initial capture or production of the gas and its final injection or distribution to the consumer are not considered. The objective is to assess the economic interest of reusing a pipeline compared to building a new one. To reach this objective, the assessment considers and estimates the costs of all aspects that differ between the reuse and new built scenario. Thus, compression/pumping and pipeline associated costs are assessed. Figure 18 and Figure 19 show the boundaries of the assessment for respectively CO_2 and H_2 cases. In the case of reuse scenarios, it might be needed to add new additional pipeline segments to connect the pre-existing pipeline to the provider and consumer locations while, in the new built scenario, it is assumed that there would be one single pipe covering the total distance form provider to consumer.

Figure 18 - System boundary for CO_2 cases

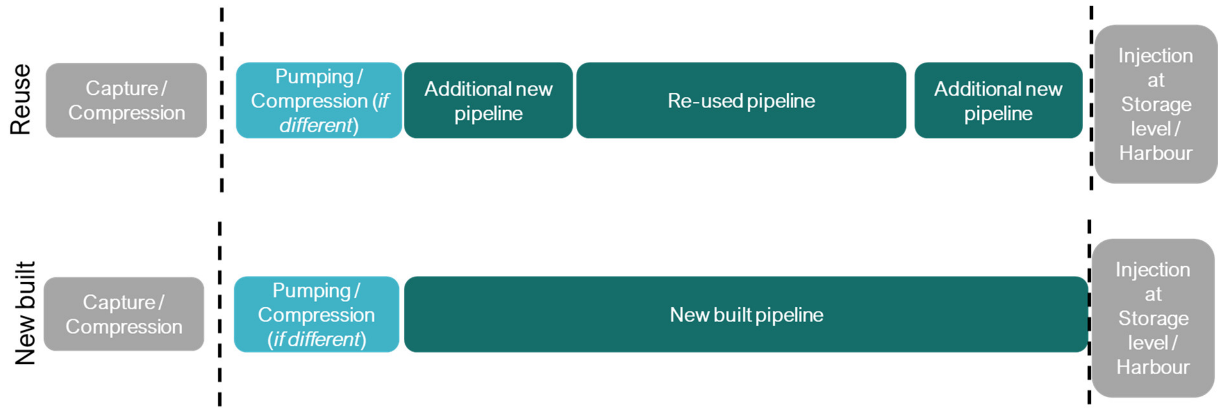
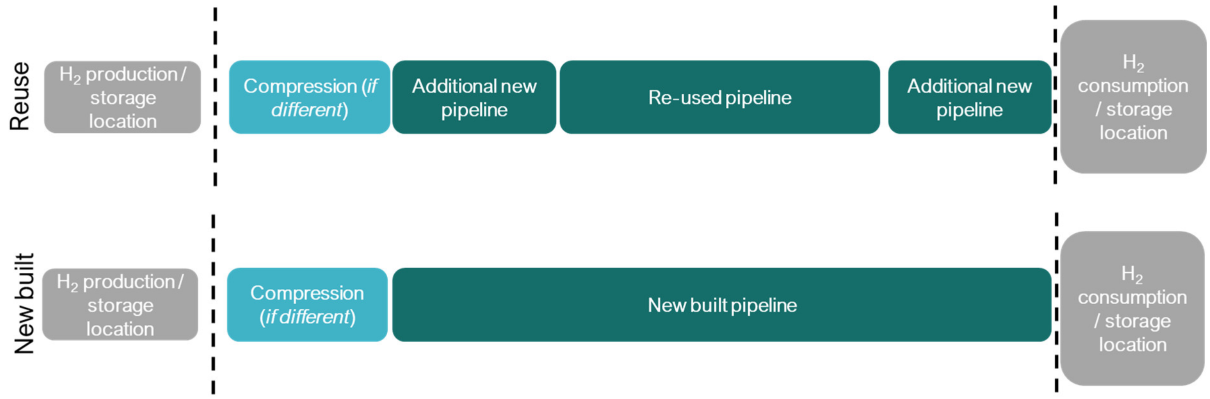


Figure 19 - System boundary for H_2 cases



The boundaries that have been set are suited to the assessment target and allow to use a similar methodology for each case.

In the cases below, the compression and pumping costs will be the same whether the pipeline is reused or new build due to similar pressure requirements:

- 1 - Fulmar - St Fergus (UK)
- 2 - Paris - Port Jérôme (FR)
- 3 - Setúbal - Leiria (PT) – capacity limited by pipeline
- 4 - P15-D - Maasvlakte (NL) – capacity limited by pipeline
- 5 - Almodovar - Merida (ES) – capacity limited by pipeline

Thus, it was chosen for these cases not to consider the compression or pumping costs in order to only assess the actual cost difference between scenarios.

6.2 Assessment assumptions

Not all case studies have the same level of certainty or data availability on key parameters. Assumptions have been taken to ensure a common assessment methodology that allows to compare cases to one another. According to the AACE (Association for the Advancement of Cost Engineering) recommended cost estimate practices and given the early stage of project definition for each case study (concept screening), the estimate class is a class V and the cost accuracy range is expected to lie between -50% to +100% for the CAPEX[48].

Cost data are from 2020.

At this stage there are some uncertainties for all cases regarding the date from which the pipelines could be decommissioned for oil and gas and become available for CO_2 and H_2 transportation. Therefore, it was assumed that scenarios presented for each case would start in 2021, which means that CAPEX are not discounted.

A project lifetime of 25 years is assumed for both re-use and new built scenarios. The equipment (compression/pumping and pipeline) could last longer[49] but the project is also highly dependent on the producer and consumer capacities.

For calculating the present value of the total CAPEX and OPEX over the project lifetime, we used a standard present value formula where CAPEX is invested in 2021 and OPEX is discounted at an assumed pre-tax rate of 8% over the 25 years of project lifetime.

Equation 1 - Present value

$$PV = CAPEX + \sum_{1}^{n} \frac{OPEX}{(1+DR)^n}$$

Where:

$n = total\ period\ duration\ (project\ lifetime)$

$DR = discount\ rate$

[48] AACE International, Cost estimate classification system – as applied in engineering, procurement, and construction for the process industries, 2005, https://www.costengineering.eu/Downloads/articles/AACE_CLASSIFICATION_SYSTEM.pdf

[49] J. Jens et al., Extending the European Backbone, April 2021. https://gasforclimate2050.eu/sdm_downloads/extending-the-european-hydrogen-backbone/

Methodology

As mentioned in section 6.1, the items in the cost assessment for CO_2 cases are pumping, compression and pipeline cost. The methodology used is presented in Table 21 and is commented in the following paragraph. Data sources can be found in Table 22.

Table 21 - CO_2 cost methodology

	Pipeline	Pumping	Compression
CAPEX	Material cost (from supplier) Laying cost Management and Engineering RFO Contingency	Carbon Limits in-house cost function based on supplier's quotes	Based on EHB mid 3.4MEUR/MWe
OPEX	1% of CAPEX, while EHB states 0.8-1.7%	5% of CAPEX from GCCSI Electricity cost	3% of CAPEX from NEC Electricity cost

Pumping

The CAPEX for pumping is calculated based on a parametric equation that Carbon Limits developed internally. The yearly fixed OPEX is set to 5% of the CAPEX (GCCSI, 2011). The variable OPEX is the electricity consumption cost. The cost for electricity is 0.0818 Euro/kWh, which is the EU 2020 average for non-household actors.

Compression

The CAPEX for compression is based on findings from the European Hydrogen Backbone (EHB) study that states a mid-cost at 3.4 MEUR/MWe. The yearly fixed OPEX is 3% of the compression CAPEX. The variable OPEX is the electricity consumption cost.

Pipeline

The pipeline CAPEX consists of 5 cost items:

1. Material: purchasing cost of new pipeline; estimated from steel pipeline supplier's cost data according to diameter, steel grade and weight.
2. Laying: installation of the new pipeline; Onshore cost based on external source from 2010 and updated according to the Chemical Engineering Plant Cost Index (CEPCI). Offshore laying cost has been assumed to be 1.5x higher than onshore cost.
3. Management and Engineering: project management related costs. Assumed this cost represents 10% of total cost.
4. Commissioning/ready for operation (RFO): Pigging and pipeline preparation work. Assumed to be 1.5% of total cost.
5. Contingency: assumed to be 30% of total cost.

The pipeline yearly fixed OPEX is assumed to be 1% of CAPEX.

In reuse scenario, the total CAPEX of a new identical pipeline is calculated and just the RFO, management and engineering (at 5% of total cost instead of 10%) and OPEX are taken into account. Thus, when the pipeline segment is reused, costs for material, laying and contingency are not considered.

The data sources for each cost category have been gathered in Table 22.

Table 22 - References for cost assessment

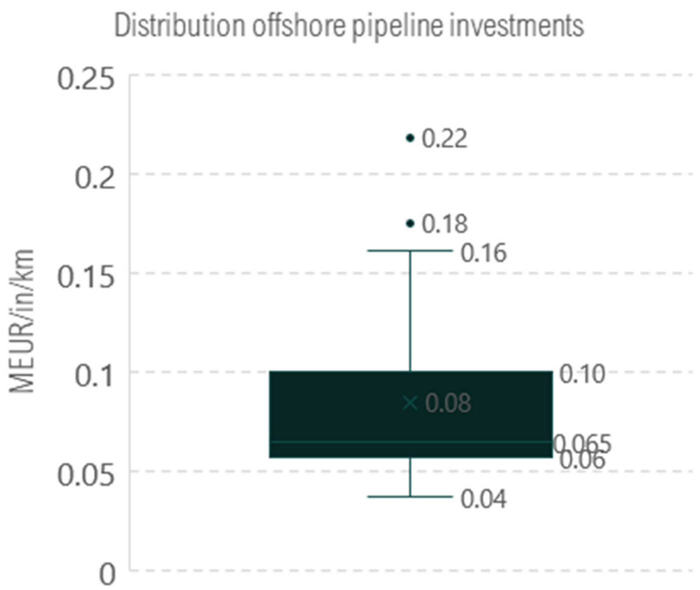
Cost items	Category	References
Pumping	CAPEX	Carbon Limits in-house cost function based on supplier's quotes
	OPEX	GCCSI: https://www.globalccsinstitute.com/archive/hub/publications/119811/costs-co2-transport-post-demonstration-ccs-eu.pdf
		Electricity: Eurostat, 2021, TEN00117 https://ec.europa.eu/eurostat/databrowser/view/ten00117/default/table?lang=en
Compression	CAPEX	EHB 2021: https://gasforclimate2050.eu/publications/
	OPEX	NEC: Bonetto, J., Catrinus, J., Malte, R., & van Schot, M., 2019. Deliverable WP1: Offshore Reuse Potential for Existing Gas Infrastructure in a Hydrogen Supply Chain As part of the project "Gas Infrastructure Opportunities for a Hydrogen Supply Chain" (p. 62). New Energy Coalition.
		Electricity: Eurostat, 2021, TEN00117 https://ec.europa.eu/eurostat/databrowser/view/ten00117/default/table?lang=en
Pipeline	CAPEX	Material: https://www.tridentsteel.co.in/carbon-steel-pipe-price-list.html
		Laying: CO_2 Europipe, 2010 updated – Gasunie laying costs / Mikunda et al, Towards a CO2 infrastructure in North-Western Europe: Legalities, costs and organizational aspects, GHGT10, 2010
	OPEX	EHB 2021: https://gasforclimate2050.eu/publications/

Box 3 - Review of offshore pipeline cost

Data source variability and comparison

A high variability in the data that has been retrieved from different sources regarding offshore pipeline costs was noticed. As an example, the figure below shows a significant uncertainty around offshore pipeline cost:

Figure 20 - Pipeline offshore cost variability in EUR 2020



Source: Carbon Limits based on several sources

Figure 20 compiles 23 published costs of recently laid / designed pipelines offshore. The average of the costs lies at 0.08 MEUR/in/km and that 50% of the data lies between 0.06 and 0.10 MEUR/in/km. Some statistical outliers from the database of 23 data points can be found, at 0.18 and 0.22 MEUR/in/km. The reasons for this scattered data are associated to, among other things, landfall costs, vessels mobilization and demobilization.

The sources and method used in this analysis are giving values between 0.08 and 0.11MEUR/in/km for the offshore new build cases. It lies in the upper side of the distribution but is still very close to the average and within the second and third quartiles. It should be noted the Re-Stream methodology considers a contingency cost of 30%.

Data sources:
https://www.globalccsinstitute.com/archive/hub/publications/119811/costs-co2-transport-post-demonstration-ccs-eu.pdf
https://www.regjeringen.no/globalassets/upload/kilde/oed/bro/2004/0006/ddd/pdfv/204688-factsog1504.pdf
https://www.baltic-pipe.eu/the-project/north-sea-offshore/

Results

For CO_2 cases, the total costs for each scenario are summarized in Table 23. Detailed cost results per cost category for each case are available in Appendix 9.2.

Table 23 shows that in the Fulmar St-Fergus case, re-using the pipeline could cost 125 MEUR whereas, if a new pipeline is built, it could cost 745 MEUR. Thus, reusing the pipeline results in a cost saving of 620 MEUR, representing 83% of cost reduction. In other words, the case of Fulmar St-Fergus has a saving potential of 2.1 MEUR per km of pipeline. For Paris – Port Jérôme case, if the project reuses the current onshore pipelines, costs savings could reach 190 MEUR or 73% compared to a new built pipeline. This results in a saving per km of 1 MEUR. In the case of Portugal, the cost saving could lie between 90 and 100 MEUR depending on the capacity used. This results in at least a 53% cost reduction and 0.9 to 1 MEUR of saving per km.

Table 23 - CO_2 cases results

		1 - Fulmar - St Fergus (UK)	2 - Paris - Port Jérôme (FR)	3 - Setúbal - Leiria (PT)	
Scenario (Capacity limited by)		Pipeline	Pipeline	Producer	Pipeline
Refer to		Table 14	Table 15	Table 16	Table 16*
Compression/pumping		not included	not included	included	not included
Capacity	Mtpa	8.9	1.5	1.2	5.2
Re-use total cost	MEUR	125	70	80	90
New build total cost	MEUR	745	260	170	190
Savings	MEUR	620 (83%)	190 (73%)	90 (53%)	100 (53%)
	MEUR/km	2.1	1.0	0.9	1.0

Note: When compression/pumping are the same between the reuse and new build cases, it was chosen not to consider their costs in order to only assess the actual cost difference between scenarios
Source: Re-Stream analysis

It is possible to notice that cost savings range from 53 to 83% and that cost saving per km lies around 1 MEUR/km for onshore scenarios and 2 MEUR/km for the offshore scenario. Some of the studied cases have already existing long pipelines and a small need for extra segment while others have a relatively short existing pipeline that will require a significant length of new segment connecting it to the producer or consumer. Cost savings are directly linked to the need for a significant amount of new pipeline relative to the pre-existing length. This relation is illustrated and analyzed further in section 6.5.

Box 4 - Cost savings in a CCS chain when considering reuse

The results presented can be compared in a broader perspective to the cost of a CCUS value chain. To do so, the total mass of transported CO_2 over the project lifetime is discounted using a similar formula as the one presented in Equation 1 - Present value on page 47. Then cost per ton of CO_2 is computed for each case:

Table 24 - CO_2: cost reduction per ton of CO_2 discounted

		1 - Fulmar - St Fergus (UK)	2 - Paris - Port Jérôme (FR)	3 - Setúbal - Leiria (PT)	
Capacity limited by		Pipeline	Pipeline	Producer	Pipeline
Capacity	Mtpa	8.9	1.5	1.2	5.2
Cost reduction	EUR/tonCO_2	6.5	11.9	7.1	6.4

The price per ton of CO_2 discounted ranges from 6 to 12 EUR/tonCO_2.

A typical cost of a CCS chain is:

- 20 – 50 EUR / t for transport and storage (low end: large onshore storage + pipeline transport - high end: ship transport / intermediate storage / offshore storage / first movers)
- 20 – 100 EUR / t for capture / conditioning (low end – high CO_2 concentrated flue gases)

Reusing a pipeline represents 10-15% of cost reduction compared to the costs of a typical CCUS value chain.

6.4 H_2 case studies

Methodology

The cost assessment methodology for 100% H_2 case studies is the same as the one used for CO_2 cases except for the fact that compression instead of pumping is needed for H_2 transport.

Table 25 - H_2 cost methodology

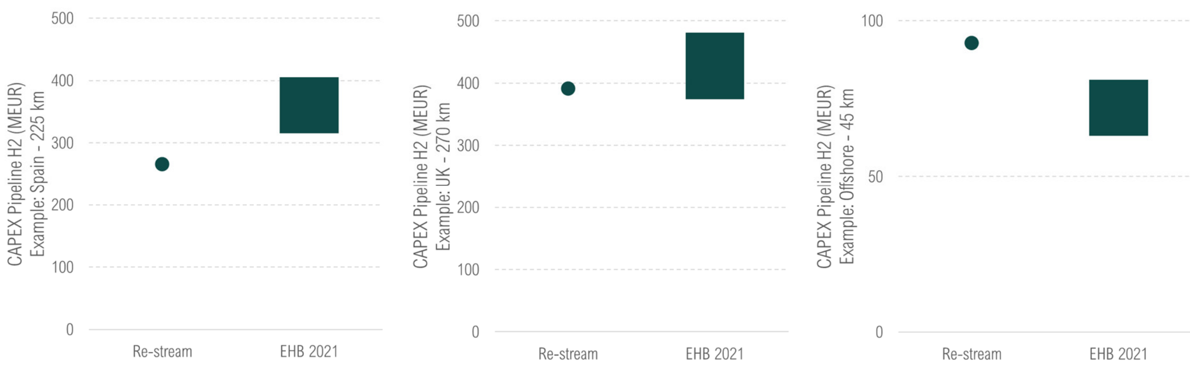
	Pipeline	Compression
CAPEX	Material cost (from supplier)	Based on EHB mid 3.4 MEUR/Mwe
	Laying cost	
	Management and Engineering	
	RFO	
	Contingency	
OPEX	1% of CAPEX, while EHB states 0.8-1.7%	3% of CAPEX from NEC
		Electricity cost

Data sources for the cost assessment are also the same as for the CO_2 cases and can be found in Table 22 on page 49.

Box 5 - H_2: comparison with other relevant sources

Figure 21 compares Re-Stream results with the recent European Hydrogen Backbone (EHB) study. The EHB 2021 study provides costs for onshore pipeline. Here, the cost assumptions provided in EHB are applied to the assessment cases and are compared to the results obtained with the Re-Stream methodology. For H_2 onshore cases (Spain and UK), the bottom-up approach used in Re-stream leads to results lying a bit below EHB's range. In terms of offshore cost, the Re-Stream methodology naturally lies slightly higher than EHB because EHB is based on onshore costs.

Figure 21 – Pipeline H_2 cost comparison with EHB 2021



Source: Re-Stream / EHB 2021

Results

Cost assessment results are synthesized in Table 26 and detailed cost estimation per category can be found in Appendix 9.2. Table 26 shows that for the Dutch case study, the reuse total cost lies between 30 to 35 MEUR while it would cost 105 to 155 MEUR to build new pipelines depending on the capacity assessed. This leads to a cost saving of 75 to 120 MEUR which represents a cost saving of 72 to 76%. The saving per km lies between 1.6 and 2.6 MEUR/km.

For the Almodovar - Merida case, the cost represents 55 to 60 MEUR to reuse pipelines and 295-300 MEUR to build new ones. This leads to a saving potential of 240 MEUR or 80-82% cost reduction where 1.1 MEUR/km could be saved.

In the case of Feeder 13, the reuse cost would lie between 120 to 260 MEUR while it would reach 360 to 700 MEUR to build new pipelines. The savings generated if pipelines are reused could represent 240 to 440 MEUR. That could lead to a cost reduction of 63 to 67% and a saving per km of 0.9 to 1.7 MEUR.

Table 26 - H_2 cases results

		4 - P15-D - Maasvlakte (NL)		5 - Almodovar - Merida (ES)		6 - Feeder 13 (UK)	
Scenario / Capacity limited by		Producer	Pipeline	Consumer	Pipeline	Consumer	Pipeline
Refer to		Table 18		Table 19		Table 20	
Compression		included	not included	included	not included	included	included
Capacity	TWh/y	8.8	22.1	0.7	2.3	1.1	12.5
Re-use total cost	MEUR	35	30	60	55	120	260
New build total cost	MEUR	155	105	300	295	360	700
Savings	MEUR	120 (76%)	75 (72%)	240 (80%)	240 (82%)	240 (67%)	440 (63%)
	MEUR/km	2.6	1.6	1.1	1.1	0.9	1.7

Note: When compression are the same between the reuse and new build cases, it was chosen not to consider its costs in order to only assess the actual cost difference between scenarios

Source: Re-Stream analysis

According to the results presented for H_2 cases, it is possible to confirm the strong potential of reuse scenarios for cost saving. Indeed, the H_2 cases present a range of 63 to 82% cost reduction and it is also possible to notice a difference between offshore and onshore cases, where savings per km are higher for offshore cases (1.6-2.6 MEUR/km) than for onshore cases (0.9-1.7 MEUR/km). Furthermore, taking Feeder 13 as an example, significant savings can be achieved even though the pipeline is used at 9% of its original capacity. Moreover, the cost saving in terms of percentage tends to stay about the same regardless of the capacity limiting factor. Finally, it is also possible to observe the influence of the extra pipeline segment on the cost reduction potential, where cases with longer extra segments have a smaller cost reduction potential. This relation is explained in section 6.5.

Box 6 - H_2: Cost savings in a hydrogen chain when considering reuse

The H_2 results can be compared to the cost of blue and green H_2 value chain. To do so, the total mass of transported H_2 over the project lifetime (considered constant as a simplification i.e. without a use pattern) is discounted following a similar formula as in Equation 1 - Present value on page 47. Then cost per kg of H_2 is computed for each case:

Table 27 - H_2: cost reduction per kg of hydrogen discounted

		4 - P15-D - Maasvlakte (NL)		5 - Almodovar - Merida (ES)		6 - Feeder 13 (UK)	
Capacity limited by		Producer	Pipeline	Consumer	Pipeline	Consumer	Pipeline
Capacity	TWh/y	8.8	22.1	0.7	2.3	1.1	12.5
Cost reduction	EUR/kgH_2	0.01	0.09	0.33	1.06	0.11	0.68

The cost reduction per kg of H_2 discounted is between 0.01 to 1.06 EUR/kgH_2 which is not unsignificant compared to the cost of hydrogen in a typical green or blue H_2 value chain.

6.5 Main findings

The cost assessment of the selected cases provided results that confirm the strong potential for cost reduction involving reuse of the pipelines. This is observed for both CO_2 and H_2 transport, where 53 to 82% of cost reduction can be achieved. Higher cost reduction per km can be achieved in offshore cases compared to onshore case studies, where cost reduction lies around 2 MEUR/km for offshore cases and 1 MEUR/km for onshore cases. This is because building offshore pipelines is generally more expensive than building onshore pipelines.

Those cost reductions are of particular importance in the initial phases of development of those key decarbonization options, CCS and hydrogen. Reuse of pipelines compared to new built pipeline is not only interesting from an economic standpoint it will also benefit the society as laying and building new infrastructure onshore is more and more difficult.

It has also been observed that even an under-utilized reused pipeline can lead to significant cost savings. Moreover, the sub scenarios (capacity limited by producer or pipeline) lead to different total costs but the saving potential in terms of percentage stays around the same for each case.

Effect of extra pipeline segment on cost savings

Table 28 highlights the fact that the share of additional new pipeline required varies significantly among cases. Indeed, it shows that 34% of the length required in Portugal will have to be built in the reuse scenario while this share is only of 2% for Fulmar St-Fergus for connecting to some onshore facilities. It has been mentioned in the result section that the share of new pipeline could play a significant role in the cost saving potential of each case. Indeed, a strong correlation of -0.91 exists between the share of new pipeline required and the total cost saving, which means that if the share of new pipeline required increases by 1%, the cost saving will drop by -0.91%.

Table 28 - Extra pipeline required per case

Pipeline length	1 - Fulmar - St Fergus (UK)	2 - Paris - Port Jérôme (FR)	3 - Setúbal - Leiria (PT)	4 - P15-D - Maasvlakte (NL)	5 - Almodovar - Merida (ES)	6 - Feeder 13 (UK)
existing segment (km)	289	159	68	40	215	237
extra segment (km)	5	25	35	5	10	30
total length required (km)	294	184	103	45	225	267
Share of new pipeline required	2%	14%	34%	11%	4%	11%

Figure 22 - Correlation cost saving vs share of additional new pipeline

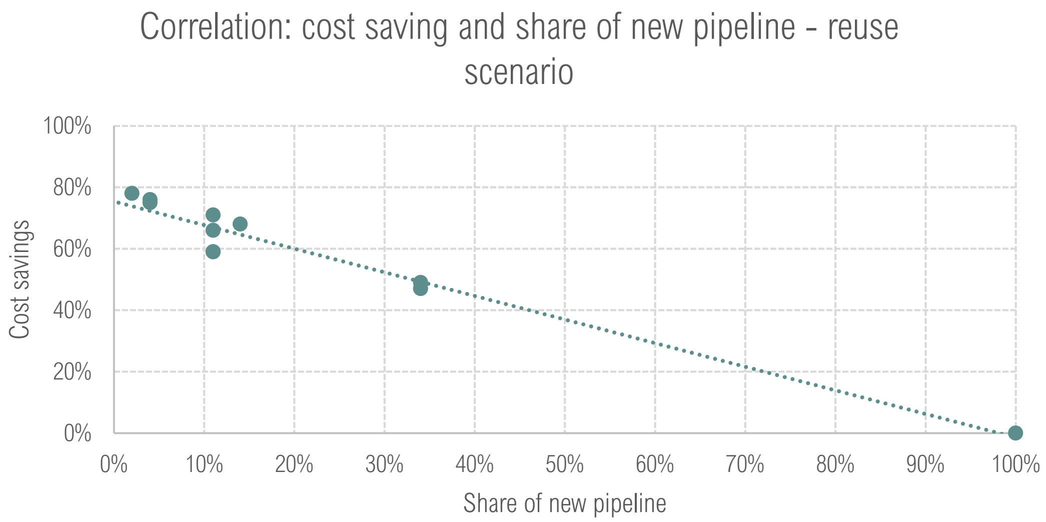


Figure 22 illustrates the correlation between the share of new pipeline in reuse scenarios and cost saving potential in comparison to new built scenarios. One can notice the strong correlation described above between variables. Furthermore, if a case study has a pipeline segment that is already well located and does not need any extra segment to connect the consumer or producer, the cost saving would peak at around 80%. This irreducible share (~20%) is linked to the assumptions considered to assess the pipeline costs.

7. Technical challenges for reuse

A list of technical challenges for pipeline reuse, including some criteria that cannot be covered at screening stages, are listed and discussed in Table 29 for H_2 and in Table 30 for CO_2. This list was completed considering the additional information collected on the different cases, the expertise available in DNV and Carbon Limits and the literature. The parameters are classified in 4 main categories: Regulatory, Integrity, Safety, Operability. Mitigation actions were identified for each of the challenges.

Table 29 – Technical challenges for reuse of pipelines for H_2 transport

Main category	Parameter	Description	Onshore	Offshore	Mitigation
REGULATORY	**Regulatory requirements**	● No current technical regulations specific for large scale hydrogen pipelines identified. It is assumed that pipelines operated with hydrogen gas will fall under the same category as for operation with natural gas, i.e. same responsible authorities and similar regulations.	x	x	● Clear regulations needed to facilitate the approval process. ● No technical showstoppers foreseen. Reuse of existing gas transport pipeline for hydrogen transport has already been done in the Netherlands (Dow Chemicals to Yara pipeline). ● Note that the European Commission launched a public consultation to gather the stakeholder opinion on the future GAS/H2 regulation. The expected legislative proposal is foreseen by end of next year.
	Current standards	● For onshore pipelines, reference is made to ASME B31.12. Additional research and testing may be required to challenge some of the criteria in the standard to unlock further the potential for reuse, in particular, this relates to higher grade steels (Vicker hardness criteria, post weld heat treatment requirement for wall thicknesses>20 mm, material derating factor, etc...). ● For offshore pipelines, there are currently no specific pipeline standards or recommended practices for transport of H_2.	x	x	● Updates of standards will help the reuse/requalification process, e.g.: H2GAR - (H_2 Gas Asset Readiness), DNV JIP for offshore H_2 pipelines ● There is an ongoing JIP (Joint Industry Project) led by DNV to develop such recommended practice referring to DNV-ST-F101 offshore pipeline code
INTEGRITY	**Metallic material**	● H_2 diffusion and embrittlement of the pipeline wall, resulting in additional requirements/limitations for higher grade steel (see limitations in current standard above). Reduction in ductility / fracture toughness.	x	x	●Testing to unlock further the potential for reuse ●Performance based method ●Small amount of O_2, N_2 may be favorable with regards to the effect of H_2 diffusion and embrittlement in steel. This is only at research stage.

Main category	Parameter	Description	Onshore	Offshore	Mitigation
	Non-metallic materials (elastomer, seals, some coating, etc)	● H_2 diffusion and material degradation	x	x	● Check for material compatibility / testing
	Welds	● Re-assessment of the fatigue life of the girth welds and long seam welds (estimate of the crack growth rate and toughness properties and determination of allowable critical crack sizes). ● Uncertainty related to initial cracks and subsequent consequence of hydrogen embrittlement on crack propagation rate.	x	x	● Additional analyses and testing
	Free span	● For offshore pipelines, re-assessment of existing free-span analyses by applying the determined stress spectrum with hydrogen fatigue capacity and new content density.		x	● New analyses and potential intervention, not expected to be critical
	Stability	● For offshore pipeline, check on-bottom stability with the change in content weight (relevant for existing gas pipelines only due to lower weight with H2 as compared to natural gas).		x	
	Other fatigue or external loading sensitive area	● Re-assess loading conditions and fatigue life (buckling, trawling, etc)	x	x	
	Valves	● Compatibility of valve stem seal arrangements and materials for hydrogen gas operation must be confirmed acceptable regarding risk of diffusive leaks and material compatibility.	x	x	● Potential replacement of components if compatibility issue, not expected to be critical
	Compressor station	● Material compatibility, leaks, performance compatibility	x	x	
	Flow metering station, controllers, instrumentations	● Material compatibility and leaks	x	x	
	Repair methods	● Confirm that current repair methods (for ex. with regards to welding procedures activities) are still applicable in case of hydrogen. This may be an issue for offshore pipeline.		x	● Potential need for technology qualification for repair method
	Internal conditions / corrosion	● Check of pipeline internal conditions / pigging. In case of corrosion, this may be counterbalanced by a potential lower required WT with the new design pressure.	x	x	● Internal inspection. Establish new required wall thickness based on new pressure rating.
	Internal flow coating (epoxy coating)	● higher velocity / change in pressure may affect the internal flow coating. The surface roughness of the internal	x	x	● Check with internal coating supplier

Main category	Parameter	Description	Onshore	Offshore	Mitigation
		flow coating should be maintained (avoid blistering) to minimize friction losses for H_2. ● Risk of H2 permeation leading to flaking and potential plugging of downstream equipment			
	Existing reparation/mitigation	● Current reparation/mitigation may not be valid for extended lifetime and new operation. Potential need for intervention.	x	x	● Re-assess existing reparation/mitigation on the line
	Running ductile fracture - H2	● Lower decompression speed but uncertainties on fracture propagation speed and effect of H_2 on material properties. Local fracture expected (no running ductile fracture).	x	x	● Confirm that running ductile fracture is not expected.
	Cathodic protection	● Status of existing cathodic protection / anodes		x	● Assess remaining life of anodes (sufficient cathodic protection or need new anodes bank)
SAFETY	**Consequence of failure or venting**	● Consequence zone in case of accidental release of hydrogen gas will generally be shorter than for current operation with natural gas. ● Venting of high pressure H2 gas	x	x	● Perform consequence analyses, tools available
	Failure probability	● Limited statistics on incidents / leaks specific to H_2 pipelines. ● If the combined load cases and effects of hydrogen gas on pipeline construction materials does not lead to a significant increase in leak or burst probability (frequency), it is considered feasible to demonstrate equivalent safety level as for current operation with natural gas.	x	x	● Confirm similar leak frequency based on load cases ● Confirm leak frequency of existing H_2 pipeline compared to natural gas pipeline.
OPERABILITY	**Compressor station bypass**	● Bypassing of existing intermediate compressor station may be needed. This is likely already possible but needs to be checked.	x	x	● Check bypassing possibility when required
	Flow induced vibration	● A check on flow induced vibrations, pulsation or acoustics should be performed for the piping for the final selected conditions, particularly if gas velocities significantly above normal conditions for natural gas is allowed for.	x	x	● New analyses
	Impurities in feed	● Different types of impurities depending on feed source ● Specifications in feed for reuse pipeline may be different than for new pipelines	x	x	● Operators to define the feed specifications in terms of allowable composition

Main category	Parameter	Description	Onshore	Offshore	Mitigation
	Change in flow direction	● Check for potential one-way equipment such as non-return valve ● modifications may be needed to reverse the flow (by-pass, ...)	x	x	● Potential modification to piping/valves
	Line packing	● potential for storage in the line will depend on new pressure rating	x	x	● New storage potential to be assessed

Table 30 – Technical challenges for reuse of pipelines for CO_2 transport

Main category	Parameter	Description	Onshore	Offshore	Mitigation
REGULATORY	**Regulatory requirements**	● Contingent liability in case of leakage pursuant to the EU Emissions Trading Scheme Directive: operators to surrender CO_2 allowances, officially termed European Union Allowances (EUAs). ● Potential prohibition of cross-border CO_2 transportation for the purposes of storage ● Regarding the storage aspect, some countries like Germany or Austria have a ban on CO_2 onshore underground storage.	x	x	● Clarifications needed for regulations on CO_2 transportation in Europe ● The reuse of an existing gas transport pipeline for CO_2 has already been done in France (Lacq CCS project). There are also already CO_2 pipeline in the North Sea
	Current standards	Specific standards for CO_2: ● ISO 27913 Carbon dioxide capture, transportation, and geological storage - Pipeline transportation systems, 2016 ● DNVGL-RP F104 Design and operation of carbon dioxide pipelines, 2021 No specific limitations/ incomplete aspects identified in the current standard and recommended practices.	x	x	● Follow the latest standards
INTEGRITY	**Metallic material**	● Potential higher risk of corrosion (in combination with water traces) ● The risk of brittle fracture should be considered for pipeline due to possible low temperatures during transport and storage of CO_2. The pipeline material needs to be resistant towards the conditions which may occur during start-ups, shutdowns or transient operations where the conditions may differ from steady state operations in addition to resist temperatures that could be obtained during depressurizing, release or leakage of CO_2 to the atmosphere.	x	x	● Material compatibility ● Strict control of water dew point and impurities

Main category	Parameter	Description	Onshore	Offshore	Mitigation
	Non-metallic materials (elastomer, seals, some coating, etc)	● Physical material degradation by CO_2 diffusion ● Chemical degradation by reaction of components in CO_2 feed ● For CO_2 dense phase transport, risk of degradation during rapid gas decompression (decompression damage caused by phase change and high solubility of CO_2 in some non-metallic materials) ● For CO_2 dense phase transport, low temperature brittleness and cracking for conditions that may occur during transient operations.	x	x	
	Running ductile fracture - CO_2	● Relevant for dense phase CO_2 transport, the pipeline should have adequate resistance against running ductile fracture. ● For offshore pipeline in combination with CO_2 dense phase transport, in case of fracture offshore, the pipeline may have after failure been exposed to highly corrosive environment. The possibility of repair must be evaluated with regards to commercial risk. ● For onshore pipeline in combination with CO_2 dense phase transport, there may only be a need to repair segments between 2 crack arrestors in case of running fracture, but the risk of the fracture running from a low safety zone to a medium safety zone should also be checked.	x	x	● Confirm that running ductile fracture is not expected or add crack arrestors
	Free span	● For offshore gas pipelines, re-assess existing free-span due to higher weight of CO_2 product and new critical free span length to identify		x	● New analyses and potential intervention
	Other fatigue or external loading sensitive area	● Re-assess loading conditions and fatigue life (buckling, trawling, ...)	x	x	
	Stability	● For offshore gas pipeline, increase weight of CO_2 as compared to natural gas may affect the embedment and heat transfer. Not expected to be critical.		x	● Confirm limited impact
	Repair methods	● Confirm that current repair methods (for ex. with regards to welding procedures activities) are still applicable in case of CO_2. This may be an issue for offshore pipeline.		x	● Potential need for technology qualification for repair method
	Internal conditions / corrosion	● Check of pipeline internal conditions / pigging.	x	x	● Internal inspection. Establish new allowable pressure rating based on minimum wall thickness.

Main category	Parameter	Description	Onshore	Offshore	Mitigation
	Internal liner/coating	● Internal coating for either flow improvement or corrosion protection may have the risk of detachment from the base pipe material in a potential low temperature condition associated with rapid pipeline depressurization. Natural gas pipelines may have internal flow coatings, and potential detachment of the flow coating should be considered if the pipeline is re-qualified to CO_2 transport	x	x	● Materials for internal coating or lining shall be qualified for the design conditions.
	External coating	● In particular for dense phase CO_2 transport, an incidental or uncontrolled depressurization of the pipeline may cause lower temperatures compared to traditional oil/ gas pipelines, and this should be considered. In case of an incidental or uncontrolled depressurization, the external coating should be examined, and its integrity confirmed including potential effect on the cathodic protection.	x	x	● Check compatibility of external coating
	Existing reparation/mitigation	● Current reparation/mitigation may not be valid for extended lifetime and new operation. Potential need for intervention.	x	x	● Re-assess existing reparation/mitigation on the line
	Cathodic protection	● Status of existing cathodic protection / anodes		x	● Assess remaining life of anodes (sufficient cathodic protection or need new anodes bank)
SAFETY	**Consequence of failure**	● Consequence zone in case of accidental release of CO_2 (due to heavier gas, dispersion different than for natural gas)	x	x	● Perform consequence analyses
	Failure probability	● Most of the statistics refer to for natural gas pipelines, a minority refer to CO_2 pipelines. Re-assess causes of failure and potential differences compared to natural gas. ● Statistics from CO_2 pipeline incidents in the U.S. Can be found at the Office of Pipeline Safety (OPS) within the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration	x	x	● Confirm leak/failure frequency
OPERABILITY	**Compressor station bypass**	● Bypassing of existing intermediate compressor station may be needed. This is likely already possible but needs to be checked.	x	x	● Check bypassing possibility when required
	Flow induced vibration	● A check on flow induced vibrations, pulsation or acoustics should be performed for the piping for the final selected conditions	x	x	● New analyses

Main category	Parameter	Description	Onshore	Offshore	Mitigation
	Heat transfer	● For offshore gas pipeline, increase weight of CO_2 as compared to natural gas may affect the embedment and heat transfer. Not expected to be critical.		x	● Confirm that the impact is limited
	Impurities in feed	● Different types of impurities depending on feed source (NOx, SOx, H2S, ...) ● Specifications in feed for reuse pipeline may be different than for new pipelines	x	x	● Operators to define the feed specifications in terms of allowable composition ● In case of H2S in the feed, the pipeline shall be evaluated for sour service
	Phase change	● For CO_2 transport in dense phase or in gas phase, crossing of the bubble point curve or dew point curve to be avoided, i.e. avoid phase change region.	x	x	● Clear definition of operating envelope and operating procedures
	Change in flow direction	● Check for potential NRV (non-return valve) ● modifications may be needed to reverse the flow (by-pass, ...)	x	x	● Potential modification to piping/valves
	Line packing	● potential for storage in the line will depend on new pressure rating	x	x	● New storage potential to be assessed

None of those challenges are seen at screening level as showstoppers though they will be reviewed during the pipeline requalification process for reuse. The typical steps of a requalification process (integrity, hydraulic analyses, safety, etc.) are for example given in the *DNVGL-RP-F104 Design and operation of carbon dioxide pipeline*. Note that it is important to assess the running ductile fracture for dense phase CO_2 and the fatigue crack growth (related to H_2 embrittlement) at an early stage as part of the requalification process, as this can limit the capacity and thus the economic interest for re-use significantly.

8. Conclusion

The Re-Stream project has confirmed the large potential of reuse of the oil and gas infrastructure in Europe for hydrogen and carbon dioxide transport.

Initial technical screening

An initial technical screening was undertaken considering the data provided by the pipeline operators. This analysis does not replace a full pipeline requalification process that would require way more inputs for each pipeline.

The criteria used for this initial screening are the material of construction and pipeline design characteristics (e.g. for CO_2, to check the resistance against running ductile fracture), the internal pipeline condition, safety matters, age and transport capacity. For calculations, design pressures have been adapted according to standards and flow requirements.

Of the approximately 58,000 km pipelines assessed in this project (around 41,700 km onshore + 16,300 offshore)[50] for which data were received, the initial screening showed that technically:

FOR CO_2

- There are no showstoppers identified for transporting CO_2 in the gaseous phase in the existing onshore and offshore pipelines.
- CO_2 transport in dense phase is possible in more than half of the offshore pipelines considering the current state of knowledge/standards. An additional 40% of the offshore length would require more testing, analyses and/or update of standards to be reusable.
- A very small portion of the onshore pipelines would be reusable for CO_2 transport in dense phase considering the current state of knowledge/standards. Approximately one quarter of the onshore length could be reusable provided positive results from more detailed analyses and/or tests.

FOR H_2

- Most of the offshore pipelines can be reused for H_2.
- Onshore, close to 70% of the pipeline total length can be reused considering the current state of knowledge/standards. The remaining length of the pipelines is promising for reuse but would require more testing and/or update of standards to be reusable. None of the pipelines analysed can be categorically excluded from reuse as of today.

It is noteworthy that for the pipelines assessed to be reusable considering the current state of knowledge/standards, pipeline requalification processes should still be undertaken, and testing might be needed. Indeed, as mentioned earlier some criteria could not be considered for this initial screening. Running ductile fracture requirements for dense phase CO_2 pipelines, fatigue crack growth for H_2 service, detailed integrity status of the pipeline and timing (date of availability of the pipeline for other use) are some of the critical factors to be evaluated as a first step of the pipeline requalification process.

[50] 28,800 km of onshore gas pipelines / 12,900 km of crude/product onshore pipelines / 16,300 km offshore pipelines of which 13,000 km of gas pipelines

Initial business opportunity review

The locations of sources (CO_2 emitters / H_2 storage / H_2 producers) and sinks (CO_2 storage locations / H_2 storage / H_2 consumers) were identified and a minimum pipeline length for business opportunities was calculated. There are some clear opportunities:

FOR CO_2

- A minimum of around 70% of the existing offshore pipeline length is relevant for CO_2 transport as many of the long pipelines are linking harbours to CO_2 storage locations.
- Regarding onshore pipelines, a minimum of 20% of the pipeline length shows some business opportunities linking sources to sinks (harbours or onshore storage sites). It is very likely that this proportion would grow significantly if the automatic approach undertaken in the study would have allowed for only part of the pipelines to be reused or for pipeline connections to be better considered.

FOR H_2

- The SMR/ATR production scenario gives a higher degree of obvious business opportunities compared to the electrolysis production one as the SMR/ATR production locations are linked to the current gas infrastructure.
- Depending on the demand/production locational scenario, the minimum reusable offshore pipeline length for hydrogen is between 2% and 25%.
- With regards to onshore, based on the demand/production locational assumptions taken in this study, the minimum reusable pipeline length for hydrogen is 20% to 30%. As for CO_2, it is very likely that this proportion would grow significantly if the automatic approach undertaken in the study would have allowed for only part of the pipelines to be reused or if pipeline connections, the security of supply and the benefits of an interconnected market had been considered[51]. According to the operators, the EU network is so well meshed that current infrastructures are likely to be enough to connect production with demand with only the last miles that would need to be added.

Case study results

For the six selected cases representing various scenarios of reuse (H_2 / CO_2 gas / CO_2 dense - onshore / offshore pipelines), no technical showstopper was found at this stage. The economic assessment of those cases confirmed the strong potential for cost reduction involving reuse of pipelines compared to their new build options. For both CO_2 and H_2 transport, 53 to 82% of cost reduction can be achieved with around 2 MEUR/km cost reduction for offshore cases and 1 MEUR/km for onshore cases. Those cost reductions are of particular importance in the initial phases of development of those key decarbonization options, CCS and hydrogen.

What's next?

A list of technical challenges for pipeline reuse, including some criteria that cannot be covered at screening stages, are listed and discussed in chapter 7. Those challenges are classified in 4 main categories: Regulatory, Integrity, Safety, Operability. Mitigation actions are identified for each of the challenges.

[51] Indeed, several producers connected to several consumers is a better model for the development of a market and to ensure security of supply.

The objective of this assessment was to estimate an overall reuse potential at EU level of the existing infrastructure and, as such, this assessment does not prevent the operators to go through a full requalification process of their pipelines before reuse. The estimated potential within this project is likely to change as the knowledge basis for transport of both H_2 and CO_2 increases and as standards evolve depending on ongoing research activities, testing and studies.

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9. Appendices

9.1 Case studies to choose from

CO_2 dense phase transport offshore

Proposed cases for selection – CO_2 dense offshore

	1 - Grane – Sture	2 - Troll B - Mongstad	3 - Troll C - Mongstad	4 - Fulmar - St Fergus	5 – P15 –D - Maasvlakte
Current operator	Equinor	Equinor	Equinor	Shell	TAQA Energy
Current Fluid transported	Oil	Oil	Oil	Gas	Gas
Dimension (D/L)	28" – 211 km	16" – 85 km	20" – 79 km	20" – 289 km	26" – 40 km
CO_2 transport capacity- initial calculation ($MtCO_2$/y)	26	9	15	8	2.5
CO_2 source	Hub in Norway – extension Northern Lights?			ACORN project extension?	Linked to Porthos project
CO_2 storage - Depleted field / Deep Saline aquifers	Several formations including Utsira, Skade – theoretical storage capacity: 1.5 $GtCO_2$	Several formations including Johansen – theoretical storage capacity: 2.2 $GtCO_2$	Several formations including Johansen – theoretical storage capacity: 1.8 $GtCO_2$	Several formations including Balder – theoretical storage capacity: 3.3 $GtCO_2$	Several formations – theoretical storage capacity: 0.006 $GtCO_2$
Location					

CO_2 gas phase transport to harbour

Proposed cases for selection – CO_2 gas to harbour

	1 – Paris – Port Jérôme	2 – Wissington - Bacton	3 – Grangemouth - St Fergus (Feeder 10)	4 – Humber cluster
Current operator	Trapil	National Grid	National Grid	National Grid
Current Fluid transported	Oil	Gas	Gas	Gas
Dimension (D/L)	20" – 170 km	36" – 90 km	36" – 250 km	48" – 85 km
CO_2 transport capacity ($MtCO_2$/y) – initial calculations	1.2	3.9	3.9	7
CO_2 source	Around Paris Waste to energy Cement Other 1.6 $MtCO_2$/y	Power station Sugar factory Pulp and paper Other 1.1 $MtCO_2$/y	Refinery Power and heat Pulp and paper Other 2.6 $MtCO_2$/y	Power station Cement Glass factory Other 10.2 $MtCO_2$/y
Harbor	Port Jérôme	Bacton	St Fergus	Humber cluster
Location				

CO_2 gas phase transport to onshore storage

Proposed cases for selection – CO_2 gas to storage

	1 – Hungary	2 - Portugal	3 – Czech Republic	4 – DE to CZ
Current operator	FGSZ	REN	NET4GAS	MERO
Current Fluid transported	Gas	Gas	Gas	Crude
Dimension (D/L)	16" - 129 km	28" - 68 km	56"- 158 km	28"- 350 km
CO_2 transport capacity ($MtCO_2$/y) – initial calculations	0.8	2.3	9.3	2.3
CO_2 source	Aluminum Sugar Factory Chemical 8.7 $MtCO_2$/y	Power plants 0.12 $MtCO_2$/y	Power plants 0.7 $MtCO_2$/y	Lime Cement Waste to Energy 1.4 $MtCO_2$/y
Storage - Depleted field / Deep Saline aquifers	Several formations – theoretical storage capacity: 0.009 $GtCO_2$	Lusitanian – 0.1 $GtCO_2$	Zatec Roudnice – 0.1 $GtCO_2$	Roudnice + Mnichovo Hradiste – 0.15 $GtCO_2$
Location				

H_2 offshore transport from wind farm to H_2 consumers

H_2 offshore transport from wind farm to H_2 consumers

	1 – P15 –D - Maasvlakte	2 – G17d-A - Uithuizen
Current operator	TAQA Energy	Neptune Energy
Current Fluid transported	Gas	Gas
Dimension (D/L)	26" – 40 km	18" - 65 km+ part of 36" - 176 km
H_2 transport capacity (TWh/y) – initial calculations	6.7	6.7 (33.3)
H_2 producer	Wind farms: Hollandse Kust Zuid Holland III – IV / Hollandse Kust Zuid Holland I - II OWF Luchterduinen – 8.8 TWh/y	Wind farms: OWF Gemini / ZeeEnergie / Veja Mate / Deutsche Bucht – 5.4 TWh/y
H_2 consumer	Rotterdam / to be distributed from there	Cities: Leeuwarden / Groningen + Industry
Location		

H_2 onshore transport from solar/wind farms- harbor to H_2 consumers

H_2 onshore transport from solar/wind farms- harbor to H_2 consumers

	1 – Lithuania	2 - France	3 – UK - Feeder 13	4 - Hungary	5 - Spain
Current operator	Amber grid	Trapil	National Grid	FGSZ	Exolum
Current Fluid transported	Gas	Product	Gas	Gas	Product
Dimension (D/L)	10/12"- 169 km	10" - 180 km	18" / 42" – 240 km	12-24" – 150 km	8 5/8" - 215 km
H_2 transport capacity (TWh/y)	3.3	2.5	8.7	3.3	3.3
H_2 producers	LNG Terminal + offshore wind farm – 6.5 TWh	Le Havre industrial area + Wind Fécamp – 2.8 TWh/y	St Fergus – 1.4 TWh/y	Industrial area – 3.9 TWh	Solar – 4 TWh
H_2 consumers	Industries (*in Latvia*)– 1 TWh/y	Paris area Airports Industries – 8 TWh/y	Edinburgh area Airport Industries – 1.1 TWh/y	Steel factory Cities – 0.7 TWh/y	Industrial clusters: Refinery Fertilizer
Location					

CARBON LIMITS DNV

9.2 Detailed cost assessment per case study

For each case, the present value of costs and the detailed CAPEX / OPEX are given in the following graphs and tables. With reference to sections 6.1 and 6.2, the uncertainty range that applies to these values given the early stage of project definition is -50% to +100% according to AACE's Class V definition.

Figure 23 – Present value of cost case 1- Fulmar - St Fergus (UK) (pumping cost not considered in cost assessment results)

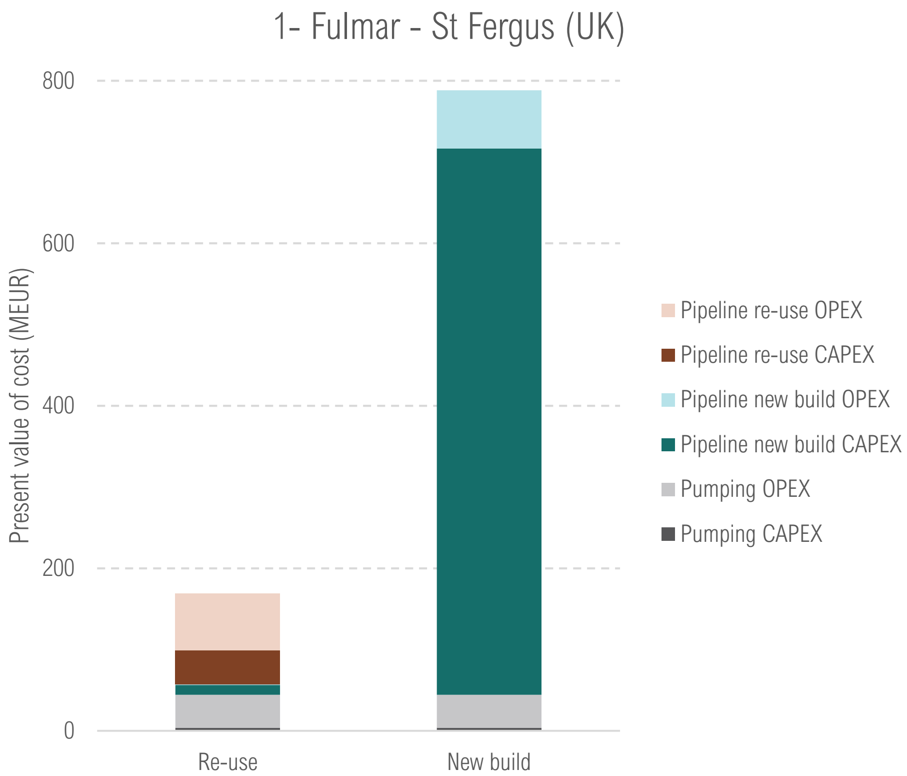

Table 31 – Detailed cost estimation 1- Fulmar - St Fergus (UK)

Parameter	1 - Fulmar - St Fergus (UK)	
Scenario	Reuse, based on pipeline capacity	New build, based on pipeline capacity
Pipeline Length (km)	289.4	289.4
Dimension OD/WT (inch/mm)	20'' OD	20'' OD / 15.8mm WT
Extra segment length (km)	5	5
Extra segment dimension (inch/mm)	20'' OD, 15.8mm WT	20'' OD, 15.8mm WT
Capacity ($MtCO_2$/yr)	8.9	8.9
New steel weight (t)	960	56 500
Pump/compressor duty (MW)	5 MW (pump)	5 MW (pump)
CAPEX (MEUR)	53	672
Reuse	41	0
New pipeline	12	672
Material	*2*	*106*
Laying	*5*	*287*
Management + RFO	*1.5*	*78*
Contingency	*3.5*	*201*
Pump/compressor	*Same pump*	
OPEX (MEUR/y)	6.6	6.6
Reuse	6.5	-
New pipeline	0.1	6.6
Pump/compressor	*Same pump*	

Figure 24 - Present value of cost case 2 - Paris - Port Jérôme (FR)

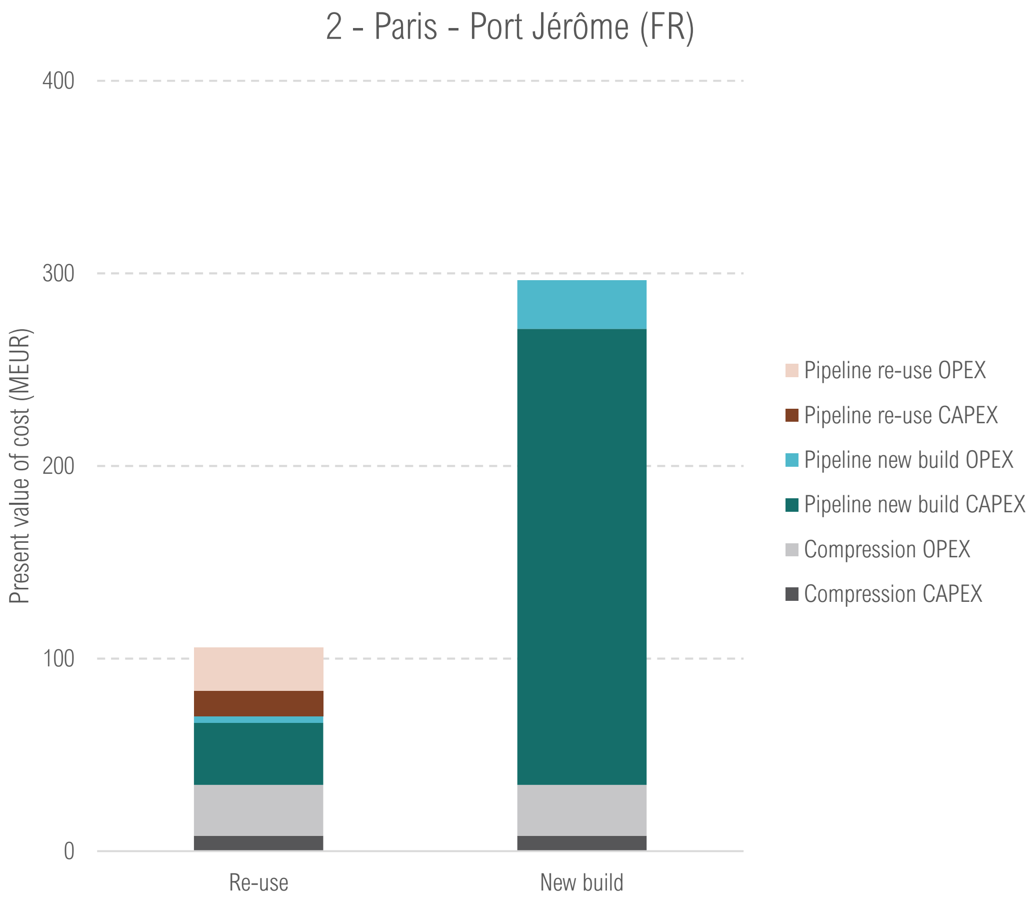

Table 32 – Detailed cost estimation 2 - Paris - Port Jérôme (FR)

Parameter	2 - Paris – Port Jérôme (FR)	
Scenario	Reuse, based on pipeline capacity	New build, based on pipeline capacity
Pipeline Length (km)	159	159
Dimension OD/WT (inch/mm)	20'' OD	20'' OD / 4.4mm WT
Extra segment length (km)	25	25
Extra segment dimension (inch/mm)	20'' OD / 4.4mm WT	20'' OD / 4.4mm WT
Capacity ($MtCO_2$/yr)	1.5	1.5
New steel weight (t)	1 350	9 980
Pump/compressor duty (MW)	2.3 MW (compressor)	2.3 MW (compressor)
CAPEX (MEUR)	45	237
Reuse	13	-
New pipeline	32	237
Material	*2.5*	*19*
Laying	*16*	*120*
Management + RFO	*3.5*	*27*
Contingency	*10*	*71*
Pump/compressor	*Same compressor*	
OPEX (MEUR/y)	2.5	2.5
Reuse	2	-
New pipeline	0.5	2.5
Pump/compressor	*Same compressor*	

Figure 25 - Present value of cost case 3 - Setúbal - Leiria (PT)

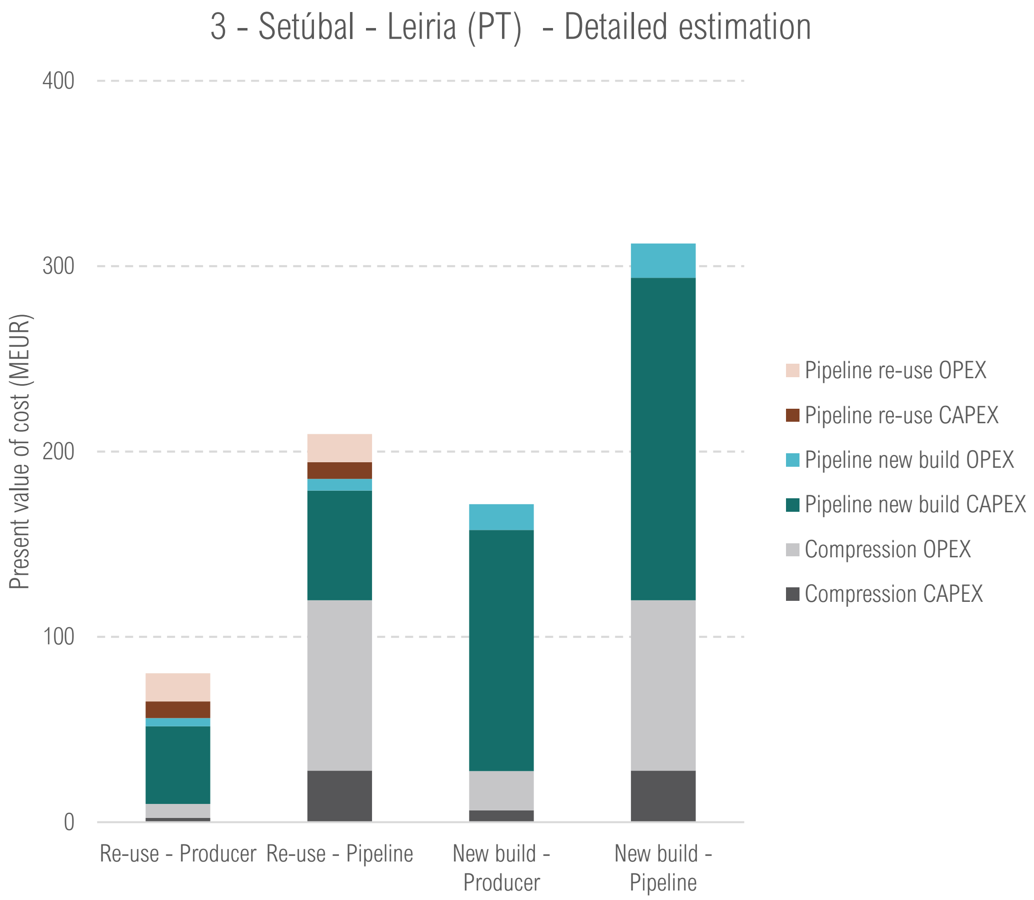

Table 33 – Detailed cost estimation 3 - Setúbal - Leiria (PT)

Parameter	3 - Setúbal – Leiria (PT)			
Scenario	Reuse, based on source capacity	New build, based on source capacity	Reuse, based on pipeline capacity	New build, based on pipeline capacity
Pipeline Length (km)	67.9	67.9	67.9	67.9
Dimension OD/WT (inch/mm)	28'' OD	16'' OD [2] / 3.8mm WT	28'' OD	28'' OD / 5.8mm WT
Extra segment length (km)	35	35	35	35
Extra segment dimension (inch/mm)	16'' OD / 3.8 mm WT	16'' OD / 3.8 mm WT	28'' OD / 5.8mm WT	28'' OD / 5.8mm WT
Capacity (Mt CO_2/yr)	1.2	1.2	5.2	5.2
New steel weight (t)	720	3 900	3 500	10 400
Pump/compressor duty (MW)	0.7 MW (compressor)	1.9 MW (compressor)	8.1 MW (compressor)	8.1 MW (compressor)
CAPEX (MEUR)	51	136	68	174
Reuse	9	-	9	-
New pipeline	42	130	59	174
Material	*2*	*9*	*12*	*35*
Laying	*23*	*67*	*23*	*67*
Management + RFO	*5*	*15*	*7*	*20*
Contingency	*12*	*39*	*17*	*52*
Pump/compressor	2	6	*Same compressor*	
OPEX (MEUR/y)	2.5	4.1	2	1.7
Reuse	1.4	-	1.4	-
New pipeline	0.4	2.1	0.6	1.7
Pump/compressor	0.7	2	*Same compressor*	

Figure 26 - Present value of cost case 4 - P15-D - Maasvlakte (NL)

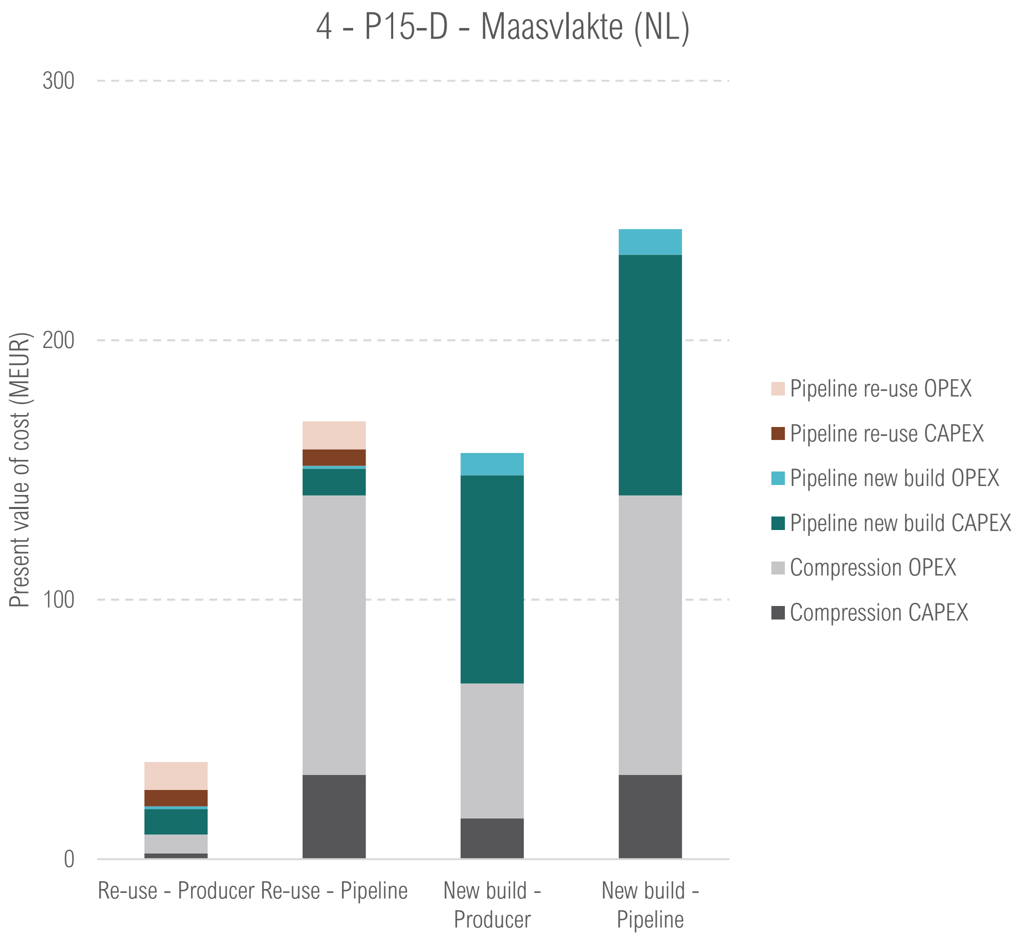

Table 34 - Detailed cost estimation 4 - P15-D - Maasvlakte (NL)

Parameter	4 – P15 –D – Maasvlakte			
Scenario	Reuse, based on source capacity	New build, based on source capacity	Reuse, based on pipeline capacity	New build, based on pipeline capacity
Pipeline Length (km)	40.1	40.1	40.1	40.1
Dimension OD/WT (inch/mm)	26'' OD	16'' OD/ 4.2mm WT	26'' OD	26'' OD/ 6.1mm WT
Extra segment length (km)	5	5	5	5
Extra segment dimension (inch/mm)	26'' OD/4.5mmWT	16'' OD/ 4.2mm WT	26'' OD/ 6.1mm WT	26'' OD/ 6.1mm WT
Capacity (TWh/yr)	8.8	8.8	22.1	22.1
New steel weight (t)	360	1 900	490	4 400
Compressor duty (MW)	0.65	4.6	9.6	9.6
CAPEX (MEUR)	18	96	16	93
Reuse	6	-	6	-
New pipeline	10	80	10	93
Material	*1*	*3*	*1*	*10*
Laying	*5*	*44*	*5*	*44*
Management + RFO	*1*	*9*	*1*	*11*
Contingency	*3*	*24*	*3*	*28*
Pump/compressor	2	16	*Same compressor*	
OPEX (MEUR/y)	1.8	5.7	1.1	0.9
Reuse	1	-	1	-
New pipeline	0.1	0.8	0.1	0.9
Pump/compressor	0.7	4.9	*Same compressor*	

Figure 27 - Present value of cost case 5 - Almodovar - Merida (ES)

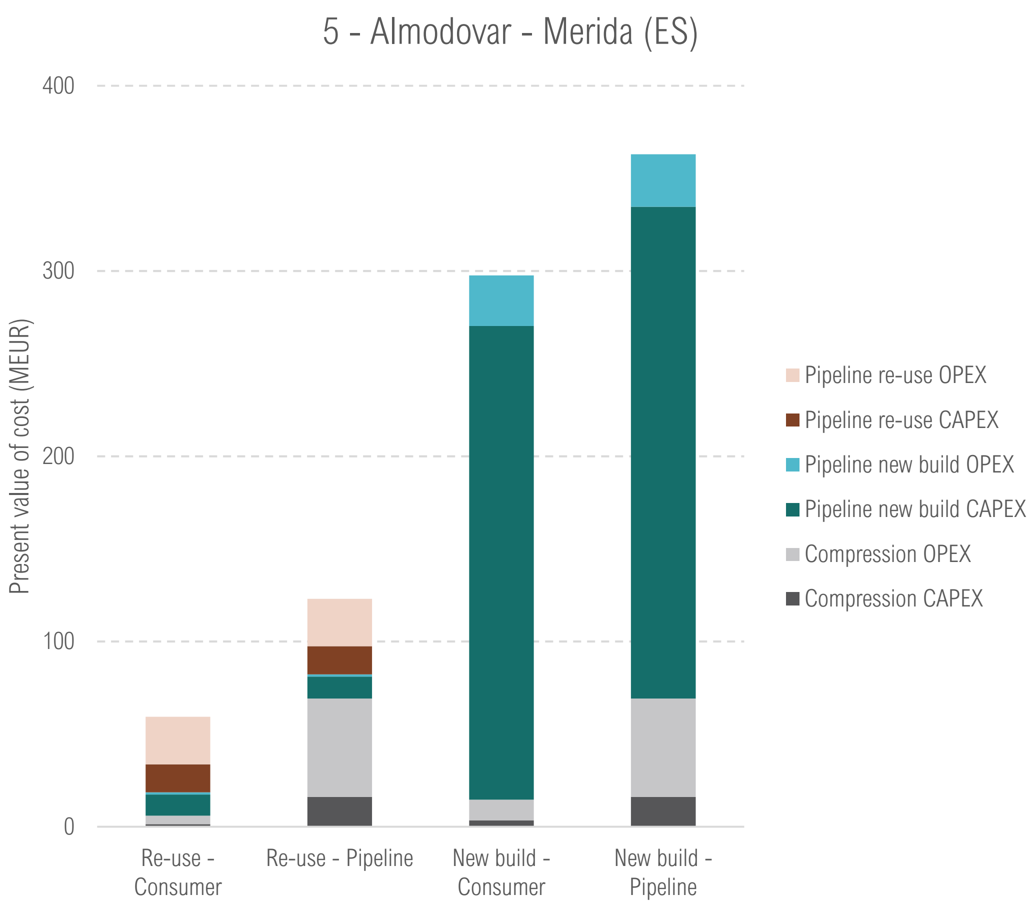

Table 35 - Detailed cost estimation 5 - Almodovar - Merida (ES)

Parameter	5 – Almodovar – Merida (ES)			
Scenario	Reuse, based on source capacity	New build, based on source capacity	Reuse, based on pipeline capacity	New build, based on pipeline capacity
Pipeline Length (km)	215	215	215	215
Dimension OD/WT (inch/mm)	8.6'' OD	6'' OD / 3.1mm WT	8.6'' OD	8.6'' OD / 5.6mm WT
Extra segment length (km)	10	10	10	10
Extra segment dimension (inch/mm)	8.6'' OD / 2.3mm WT	6'' OD / 3.1mm WT	8.6'' OD / 5.6mm WT	8.6'' OD / 5.6mm WT
Capacity (TWh/yr)	0.7	0.7	2.3	2.3
New steel weight (t)	120	2 600	290	6 600
Compressor duty (MW)	0.4	1	4.7	4.7
CAPEX (MEUR)	27	258		
Reuse	15	-	15	-
New pipeline	11	255	11.2	265
Material	*0.2*	*3*	*0.4*	*9*
Laying	*6.5*	*146*	*6.5*	*146*
Management + RFO	*1.3*	*29*	*1.3*	*30*
Contingency	*3*	*77*	*3*	*80*
Pump/compressor	1	3	*Same compressor*	
OPEX (MEUR/y)	2.9	3.6	2.5	2.6
Reuse	2.4	-	2.4	-
New pipeline	0.1	2.5	0.1	2.6
Pump/compressor	0.4	1.1	*Same compressor*	

Figure 28 - Present value of cost case 6 - Feeder 13 (UK)

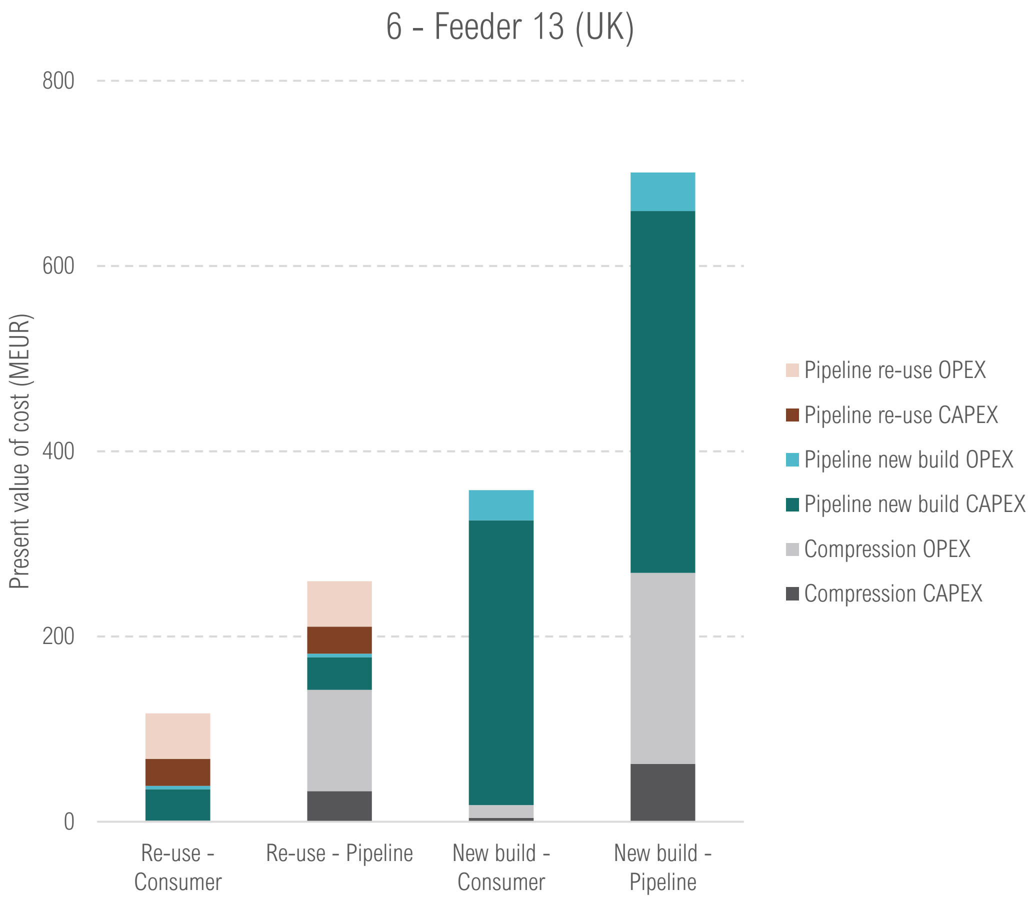

Table 36 - Detailed cost estimation 6 - Feeder 13 (UK)

Parameter	6 – Feeder 13 (UK)			
Scenario	Reuse, based on source capacity	New build, based on source capacity	Reuse, based on pipeline capacity	New build, based on pipeline capacity
Pipeline Length (km)	237.3	237.3	237.3	237.3
Dimension OD/WT (inch/mm)	18.5'' / 42.5'' OD	8'' OD / 3.3mm WT	18.5'' / 42.5'' OD	18.5'' OD/9.6mm WT
Extra segment length (km)	30	30	30	30
Extra segment dimension (inch/mm)	8'' OD / 2.0mm WT	8'' OD / 3.3mm WT	8'' OD / 5.7mm WT	18.5'' OD/9.6mm WT
Capacity (TWh/yr)	1.1	1.1	12.5	12.5
New steel weight (t)	200	4 400	850	29 100
Compressor duty (MW)	0.080	1.200	9.7	18.3
CAPEX (MEUR)	63.3	311	97	453
Reuse	29	-	29	-
New pipeline	34	307	35	391
Material	*0.3*	*6*	*1.2*	*55*
Laying	*19.5*	*174*	*19.5*	*174*
Management + RFO	*4*	*35*	*4*	*45*
Contingency	*10.2*	*92*	*10.3*	*117*
Pump/compressor	0.3	4	33	62
OPEX (MEUR/y)	1.5	4.3	11.5	23
Reuse	1.1	-	1.1	-
New pipeline	0.3	3	0.4	4
Pump/compressor	0.1	1.3	10	19