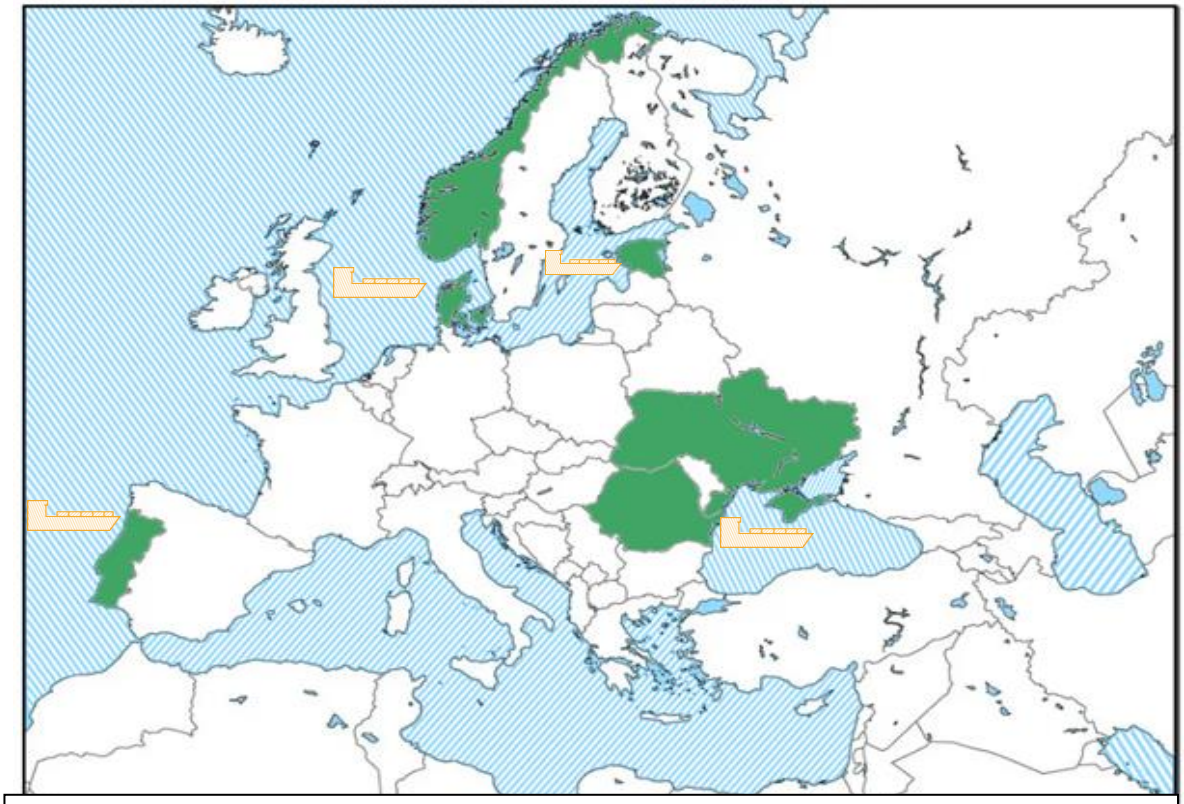
CO2 Transport and Storage directly from a ship: flexible and cost-effective solutions for European offshore storage

Deliverable 3.1

Techno-economic evaluation report



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Executive Summary

This report develops a bottom-up techno-economic assessment for full carbon capture and storage (CCS) chains covering capture, conditioning, transport, and geological storage, applied to four European regions: the Baltic Sea, the Black Sea (Ukraine and Romania), the North Sea and the Atlantic coast of Portugal. The purpose of this work is to perform a techno-economic evaluation of the direct injection of CO_2 from a ship (DSI) when compared with its relevant alternatives; a dedicated pipeline (PIPE-scenario) and conventional shipping with offloading at an offshore platform (SHIP).

DSI is currently at TRL 4–5; the strong parallels with established offshore oil and gas technologies support its technical credibility, but the ship-to-subsea connection and intermittent-injection performance still require demonstration.

The evaluation extends the TEA tool developed in the Horizon 2020 STRATEGY CCUS project, with a dedicated direct-injection module, and reports costs as net present costs in 2030 euros (at a 5% discount rate and over a maximum scenario timeframe of 35 years, 2031-2065), alongside energy use and chain emissions. The results correspond to an AACE Class 4 feasibility-stage cost estimate with expected accuracy of -30% to +50%.

Capture costs dominate the chain. In every region, capture accounts for the majority of costs and energy use. Its share of discounted full-chain costs ranges from around 65% in the North Sea scenario case, to nearly 90% in Portugal. Transport mode is therefore a second-order question at full-chain level: the spread between the cheapest and most expensive transport configurations is generally within a few percent of total costs. The decisive full-chain levers are the capture stage and the participation of a few anchor emitters that underpin the economics of any shared network.

When a pipeline option is feasible, it is the lowest-cost option. In the three regions where a pipeline was assessed, PIPE has the lowest cost for the transport and storage portion of the chain. In Romania, the normalised transport-and-storage costs of DSI and SHIP are about 28% and 35% above PIPE, respectively; in Portugal, DSI is about 54% higher in absolute transport and storage costs (55% per tonne abated). Ukraine shows the same ranking, with DSI cheaper than SHIP but remaining above PIPE. PIPE also has the lowest chain emissions and non-capture energy demand in the Ukrainian, Romanian and Portuguese scenarios.

Conventional shipping and direct injection costs are often close, with a structural trade-off. DSI removes the need for a fixed offshore platform (or equivalent on-land infrastructure for CO_2 conditioning before injection), thereby saving substantial storage CAPEX. It reduces storage CAPEX by about 47% relative to SHIP in the Baltic case and avoids several billion euros of fixed storage infrastructure in the gigatonne-scale North Sea network. That saving is offset by higher transport costs due to onboard reconditioning before injection, dynamic positioning and marine fuel consumption. In the Baltic Sea, SHIP is about 6% cheaper for transport and storage, while DSI removes the platform, delivers slightly higher net abatement and provides greater flexibility.

Carbon intensity of the electric energy use/grid decides outcome. Handling CO_2 requires energy. In the North Sea case, where the local grid is among the cleanest in Europe (30–80 gCO_2e/kWh), powering fixed injection from shore is far less carbon intensive than burning marine diesel onboard (500–600 gCO_2e/kWh for the same service). DSI is about 3% cheaper in absolute transport and storage costs and costs per tonne stored, but its higher chain emissions make it more expensive per tonne abated. The cluster analysis bears this out: small, local clusters favour DSI, whereas long-distance, high-

volume port clusters favour conventional shipping. Decarbonised ship fuel or onboard capture would strengthen DSI; gas-turbine-powered fixed injection would narrow the emissions difference.

Direct injection from a ship is technically credible and economically competitive with conventional shipping wherever the sea is the only practical route to the storage facility. Its distinctive value lies in the elimination of fixed offshore infrastructure, and the flexibility this gives to smaller or early mover projects, rather than a headline cost advantage over pipeline. The strongest cases for DSI are dispersed and modest volume emitters, regions without a pipeline viable option and possibly regions with variable or shallow water depth. The weakest case for DSI is when considering gigatonne-scale injection, long-haul chains served by long centralized pipelines, and when decarbonisation of ship fuel is needed to keep DSI attractive per tonne of CO_2 abated.

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Abbreviations

AACE	Association for the Advancement of Cost Engineering (Class 4 cost-estimate classification)
API 5L (X70)	American Petroleum Institute line-pipe specification; X70 high-strength low-alloy steel grade
BEC	Bare Erected Cost
BECCS	Bio-Energy with Carbon Capture and Storage
BEIS	(UK) Department for Business, Energy & Industrial Strategy
CAPEX	Capital Expenditure
CC	Carbon Capture (e.g. Post-CC)
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCSA	Carbon Capture and Storage Association
CCUS	Carbon Capture, Utilisation and Storage
CETP / CET Partnership	Clean Energy Transition Partnership
CTS	CO_2 Transport and Storage (project)
DP	Dynamic Positioning
DSI	Direct Ship Injection (scenario)
E	Emitter (followed by a number referring to the numbered emitter list in each scenario table)
EN-H_2	National Hydrogen Strategy (Portugal)
ETS	Emissions Trading System
EU	European Union
EUDP	Energy Technology Development and Demonstration Programme (Denmark)
FEED	Front-End Engineering and Design
GBP	British Pound Sterling
GHG	Greenhouse Gas
H2020	Horizon 2020
LCO_2	Liquefied CO_2
LULUCF	Land Use, Land-Use Change and Forestry
MEA	Monoethanolamine (post-combustion capture solvent)
MGO	Marine Gas Oil
MMV	Measurement, Monitoring and Verification
NECP	National Energy and Climate Plan
NPC	Net Present Cost
OPEX	Operating Expenditure
PCI	Project of Common Interest
PF	Pulverised Fuel (e.g. Coal PF Super-C)
PIPE	Pipeline (scenario)
PnA	Plug and Abandonment
PNEC	National Energy and Climate Plan (Portugal)
PP	Power Plant
RCN	Research Council of Norway
RNC 2050	Carbon Neutrality Roadmap 2050 (Portugal)

ROV	Remotely Operated Vehicle
S#	Scenario number
SFOC	Specific Fuel Oil Consumption
SHIP	Conventional CO_2 ship (scenario)
SINTEF	Norwegian research organisation (cost-application source)
SU	Storage Unit (followed by a number referring to the numbered storage-unit list in each scenario table)
TEA	Techno-Economic Assessment / Evaluation
TRL	Technology Readiness Level
UEFISCDI	Executive Agency for Higher Education, Research, Development and Innovation Funding (Romania)
WP	Work Package

Units

Parameter	**Unit**
CO_2 mass (captured / transported / stored / abated)	Mt, $MtCO_2$, tCO_2, t
Annual CO_2 throughput / capture rate	$MtCO_2/yr$
Injection / loading / unloading rate	tCO_2/h, t/h
Capture specific energy (energy penalty factor)	$TJ/MtCO_2$
Liquefaction specific energy	kWh/tCO_2
Specific fuel oil consumption (SFOC)	g/kWh
Electricity price	€/MWh
Grid carbon intensity (electricity CO_2 emissions)	gCO_2e/kWh
Natural-gas emission factor	tCO_2/tNG
Diesel CO_2 emission factor	$tCO_2/tDiesel$
Specific chain / segment cost	$€/tCO_2$
Liquefaction / buffer-storage CAPEX (per annual capacity)	$€/tCO_2/yr$
Loading & unloading CAPEX	€/t/yr
Natural-gas price / fuel cost (Marine diesel oil)	€/t
Steel price	€/t
Crew costs	€/day
Harbour fee	€
Well drilling, P&A, seismic, injection-system CAPEX	€M (million €), €B (billion € = 1000 €M)
Cost reference / monetary base year	€2030
Transport / storage / injection pressure	bar
Temperature (transport, injection, seawater)	°C
Sailing speed	knots
Distance / pipeline length / reservoir depth	km, m
Rail tank-wagon volume	m^3
Capture efficiency, OPEX (% of CAPEX), inflation, discount rate, volume margin, terrain factors	%
Operation period	yr / years
Annual operating time	h (hours)
Technology Readiness Level	TRL (dimensionless, 1–9)

1 Introduction

Carbon Capture and Storage (CCS) is widely recognised as an essential pillar of Europe's decarbonisation strategy. The European Green Deal[1], the Fit for 55[2] package and the Net-Zero Industry Act[3] have collectively set the ambition of climate neutrality by 2050, with an interim target of at least 50 million tonnes of annual CO_2 injection capacity in the EU by 2030. For several hard-to-abate sectors — including cement, steel, refining, chemicals, and waste-to-energy — CCS represents the only mature technological pathway capable of delivering deep emission reductions at the scale and within the timeframe required. Reflecting this strategic role, a growing portfolio of large-scale CCS projects is taking shape across Europe, including Northern Lights in Norway, Porthos and Aramis in the Netherlands, Greensand in Denmark, and several emerging initiatives in the United Kingdom, France, and the Mediterranean. This evolving landscape brings into focus the need to better understand how CO_2 can be transported between capture sites and storage locations, and at what cost.

1.1 Context and motivation

CCS chain costs are inherently site- and region-specific. They depend on the type and scale of the emitter, the distance and route between the capture point and the storage site, the transport mode selected, and the geological characteristics of the reservoir. As a result, published cost figures for CCS chains vary widely and are often difficult to compare directly, since they are based on different scopes, assumptions, boundary conditions, and reference years. This is particularly true when comparing alternative transport solutions. Pipelines, conventional shipping with offshore platform offloading, and direct ship injection into subsea wells each present distinct cost structures, technical maturities, and sensitivities to project parameters such as volume, distance, and water depth. Without a consistent and transparent methodology, it is challenging for project developers, policymakers, and infrastructure planners to assess which transport option is most suitable for a given region and emitter profile. A common analytical framework is therefore needed to enable a like-for-like comparison of CCS chain costs across Europe.

1.2 Objective and scope of the report

This report presents a techno-economic evaluation (TEA) methodology for full CCS chains — covering capture, conditioning, transport, and storage — and applies it to four European regions selected to reflect a range of emitter profiles, transport distances, and storage settings. The central objective is to compare three transport configurations on a consistent basis: pipeline transport, conventional shipping to an offshore platform, and direct ship injection into subsea wells. For each configuration and region, the methodology produces cost metrics expressed in €/tCO_2 for each segment of the chain, as well as a total chain cost, enabling direct comparison between transport modes and across regions.

The scope of the analysis covers the technical sizing, CAPEX, and OPEX of the main equipment and infrastructure required along the chain, together with the reservoir-driven parameters that determine well count and injection pressure on the storage side. The report does not address CO_2 utilisation pathways, policy or subsidy mechanisms, detailed permitting and regulatory processes, or financing

[1] European Commission. (2019). *The European Green Deal* (COM(2019) 640 final).
[2] European Commission. (2021). *'Fit for 55': Delivering the EU's 2030 climate target on the way to climate neutrality* (COM(2021) 550 final).
[3] European Union. (2024). *Regulation (EU) 2024/1735 of the European Parliament and of the Council of 13 June 2024 on establishing a framework of measures for strengthening Europe's net-zero technology manufacturing ecosystem (Net-Zero Industry Act).* Official Journal of the European Union, L, 2024/1735.

structures. The intent is to provide a transparent and reproducible cost basis that can support further studies, project screening, and strategic decisions on the deployment of CCS infrastructure in Europe.

1.3 The StrategyCCUS TEA tool

The techno-economic evaluation presented in this report builds on the methodology and tool developed within the StrategyCCUS project, a Horizon 2020 initiative that ran between 2019 and 2023 with the aim of supporting the deployment of CCUS in Southern and Eastern European regions. The project focused on a set of promising industrial clusters — including the Ebro Basin in Spain, the Paris Basin and Rhône Valley in France, the Lusitanian Basin in Portugal, West Macedonia in Greece, and additional sites in Romania, Poland, and Croatia — and produced a comprehensive assessment of CO_2 sources, transport routes, and storage opportunities across these regions. StrategyCCUS developed a dedicated TEA tool capable of evaluating the full CCS chain, from capture at the emitter through conditioning, transport, and final storage in the reservoir, producing consistent cost metrics for each segment and for the chain as a whole.

The tool is not publicly available and remains restricted to project partners. For the present work, the tool has been updated to extend its transport module with a more detailed direct ship injection evaluation, complementing the previously available pipeline and conventional ship-to-platform options. This update enables, within the same analytical framework, a like-for-like comparison of all three transport-to-storage configurations across the four European regions covered by this report.

The remainder of this report is organised as follows:

- Chapter 2 presents the methodology underpinning the techno-economic evaluation, starting with the capture cost model (Section 2.1) and the transport cost models (Section 2.2), which cover the general liquid CO_2 transport assessment, conventional shipping, ship with direct injection, pipeline, train, and barge options. Storage cost modelling is described in Section 2.3, followed by the framework for building integrated scenarios and computing full-chain costs in Section 2.4, and the common regional assumptions adopted across the case studies in Section 2.5.
- Chapter 3 to 7 applies this methodology to the four European regions: the Baltic Sea, the Black Sea—Romania, the Black Sea—Ukraine, the North Sea, and the Atlantic Coast of Portugal. Each regional case study introduces the scenario considered, the main characteristics of the emitters, transport routes, and storage sites, and presents the TEA results broken down by capture, transport, storage, and full chain. Where relevant, the regional chapters also discuss recent regulatory and technological developments, long-term cost evolution, additional CO_2 emissions associated with the chain, and perspectives for direct ship injection.
- Chapter 8, discusses the future perspective of the direct injection from ship DSI technology
- and chapter 9 outlines the main conclusions of the report.

The report integrates also two annexes. Annex A is related to dynamic positioning conditions for ships, specific for each region, and Annex B that details the methodology applied to forecast future emissions in the Portuguese facilities.

The presentation of the regional assessments varies slightly in the structure and format. These differences reflect the specific characteristics of each region, including the number and distribution of emitters, transport configurations, storage options and availability of regional data, as well as input from the local teams responsible for developing and validating each scenario. Nevertheless, all regional assessments follow the same methodological framework and cost assumptions, ensuring that the principal results remain consistent and comparable across regions.

2 Methodology

The methodology for assessing the costs of CCS scenarios follows a bottom-up approach, covering the full CCS chain from CO_2 capture at the emission source to its transport by pipeline and/or ship to a permanent offshore storage site. The assessment is applied to the CTS target regions, with several scenarios defined for each, reflecting different technical configurations, transport options, and storage destinations. Although the analysis is high-level in nature, the bottom-up approach was adopted to retain enough granularity in the cost build-up to identify the main cost drivers and enable consistent comparison between regions and scenarios. The CCS chain is disaggregated into its main components, each designed according to the characteristics of the scenario under analysis. Individual component costs are calculated and then aggregated into total costs, adjusted for inflation and discounted to present value. Figure 1 presents a schematic overview of the main components considered: CO_2 capture, pipeline transport, ship transport and geological storage and the integration of these into the overall cost assessment. Ship transport was further analysed in two configurations, one in which a conventional ship is used for transport to the storage site and, a second one in which the ship has a direct injection capability. Transport by barge and rail were considered only for the Romanian scenario. Each component, along with the underlying assumptions and economic parameters, is described in detail in the following sections.

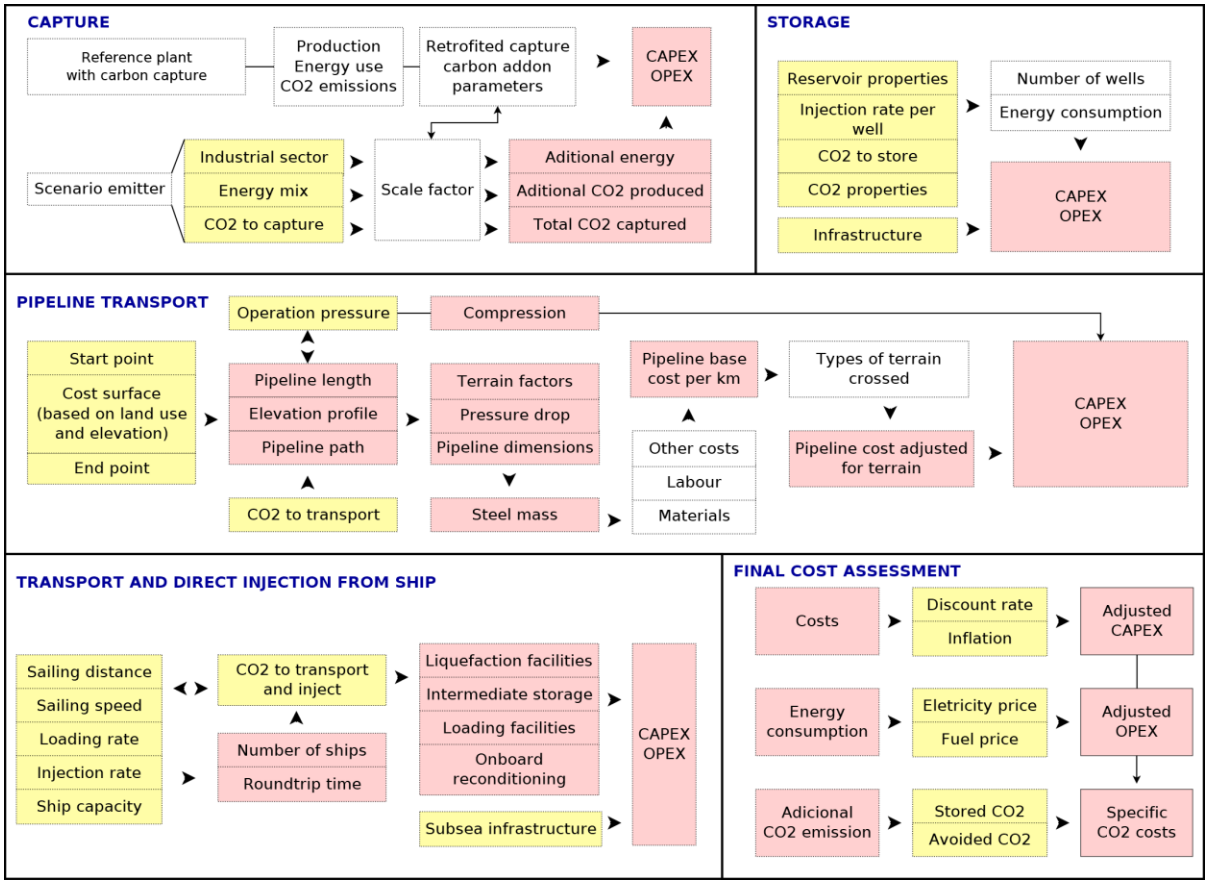


Figure 1. Simplified schematics of the methodology used.

2.1 Capture

The capture assessment estimated the economic costs, additional CO_2 emissions, and energy requirements associated with retrofitting existing CO_2 emitting sources with carbon capture facilities across European regions with distinct industrial and electricity generation characteristics. A single capture technology was applied to all stationary emission sources to enable consistent cross-regional comparison. Post-combustion monoethanolamine *(*MEA*)* based CO_2 capture was selected for its broad applicability and high technology readiness level (TRL), despite its significant energy consumption, providing a consistent basis for quantifying additional energy demand and capture-related emissions critical for evaluating CO_2 transport and storage needs.

Reference cases were established for each industrial sector, defining production capacity, CO_2 emissions, and characterizing retrofit capture systems in terms of CAPEX and fixed OPEX (covering fixed costs such as maintenance and labour). Each scenario is assessed by scaling these reference cases to the facilities under analysis using a scaling exponent of 0.6, incorporating site-specific information — such as local energy mix — where available. Variable OPEX was estimated as a function of energy demand for capture.

Since flue gas composition, temperature, and outlet pressure differ significantly between industries, sector-specific energy penalty factors are applied and calculations performed individually for each emitter (Table 1). This factor represents the energy required per tonne of CO_2 captured.

Table 1. Considered industries and specific energy required to capture CO_2.

Industry	Energy factor, TJ/MtCO_2	Energy factor, TWh/MtCO_2
Steel	3800	1.06
Refinery	4200	1.17
Cement	3190	0.89
Chemistry	4000	1.11
Incinerator	3400	0.94
Pulp & Paper	4000	1.11
Glass	3950	1.10
Coal PF Super-C Post-CC	4000	1.11
Cogeneration	3500	0.97
Lignite Post-CC	4200	1.17
CCGT Post-CC	3600	1.00

The primary energy demand in this process comes from solvent regeneration, where thermal energy is required to release absorbed CO_2 from the amine solution. Additional energy is required for CO_2 compression and cooling prior to transport or storage. Thermal energy for solvent regeneration is supplied by natural gas which generates additional CO_2. An emission factor of 2.69 tCO_2/tNG was considered.

A capture efficiency of 95% was applied across all cases. Total CO_2 captured is therefore calculated as 95% of the combined emissions from the original flue gas and the natural gas used for process heat.

2.2 Transport

Transport of CO_2 was evaluated by analysing each individual connection of the transport network within a given scenario:

i) Network design: For each scenario, the transport network is designed based on the locations of CO_2 emitters, storage sites, and the available transport options. Where relevant, to produce a

coherent and less redundant network, collection hubs are introduced to aggregate CO_2 from multiple sources.

ii) Connection sizing: Each individual link of the network is designed according to CO_2 mass flow rate, transport distance, and the associated logistical constraints.

iii) Techno-economic assessment: CAPEX, OPEX, energy consumption, and additional CO_2 emissions arising from transport are quantified for each connection.

Three transport modes were assessed in detail: pipeline, conventional ship, and ship with direct injection. Two additional options, inland barge and rail (both only applied in the Romanian scenarios), were evaluated at a lower level of detail. Among all modes considered, only the pipeline transports CO_2 in dense phase; the others operate with CO_2 in liquid phase.

When evaluating the transport of CO_2 in its liquid phase, the same set of assumptions and cost elements was applied consistently across all transport modes using liquefied CO_2 (conventional ships, ships with direct injection, barges, and trains). The three key components of liquid CO_2 transport — loading and unloading, liquefaction, and buffer storage — were assessed separately for both CAPEX and OPEX. For the liquefaction process, energy consumption, regional electricity prices, and the carbon intensity of electricity were considered to estimate total energy use, energy costs, and associated CO_2 emissions. With the exception of energy required for offloading at storage sites, the energy demands of loading and unloading operations were deemed negligible and were therefore excluded from the evaluation.

The liquid CO_2 is assumed to be at medium pressure, under conditions of 15 bar and –29 °C. The calculations further assumed that the CO_2 delivered for liquefaction — whether directly from the capture plants or via pipeline — would already be in a pre-pressurised state.

Reference values used in this study and presented in Table 2 were taken from the report *Shipping CO_2 – UK Cost Estimation Study* (2018)[4], converted from GBP to EUR using the 2018 exchange rate, and adjusted to present-day values by applying a factor of 1.4 based on the producer price index from Eurostat.

Table 2. Base values for loading and unloading, liquefaction and buffer storage, adapted from "Shipping CO_2 – UK Cost Estimation Study".

	Value	Unit
Loading and unloading		
CAPEX	2.15	€/t/yr
OPEX	3	% of CAPEX
Rate	1,500–2,500	tCO_2/h
Liquefaction		
Energy	20	kWh/tCO_2
CAPEX	13	€/tCO_2/yr
OPEX	10	% of CAPEX
Buffer storage		
CAPEX	1,200	€/tCO_2
OPEX	5	% of CAPEX
Volume margin	+20%	

[4] *Shipping CO_2 - UK Cost Estimation Study* (Department for Energy Security and Net Zero, and Department for Business, Energy & Industrial Strategy, 2018).

Loading and unloading

Loading and unloading operations, excluding CO_2 injection, were designed around a nominal rate of 1,500 tCO_2/h. For the purposes of ship sizing and operational optimisation, this rate may be increased up to 2,500 tCO_2/h. Although CAPEX is expected to vary with the loading rate, a uniform cost value is assumed across this range. This simplification is justified given that the adopted cost value represents an average derived from the literature and remains adequate for the higher loading rate scenarios.

Liquefaction

The liquefaction stage converts CO_2 delivered either directly from the capture plants or through a pipeline into a liquid phase suitable for transport by ship, barge, or train. Liquefaction is assumed to bring the CO_2 to medium-pressure conditions of 15 bar and –29 °C, consistent with the transport specifications adopted in this study. Since the incoming CO_2 stream is assumed to be already pre-pressurised, the energy demand reflects mainly the additional refrigeration required to reach the target state.

A specific energy consumption of 20 kWh/tCO_2 is assumed for the liquefaction process, in line with values reported in the literature. The corresponding energy costs and indirect CO_2 emissions were calculated using region-specific electricity prices and grid carbon intensities, allowing the assessment to capture geographic variability in operating conditions. CAPEX was set at 13 €/tCO_2/yr of installed capacity, while OPEX (excluding electricity) was estimated at 10% of CAPEX, covering maintenance, consumables, and routine operational expenses. Electricity costs were treated as a separate variable cost component to preserve transparency.

Liquefaction units were assumed to be co-located with the loading terminals, eliminating the need for intermediate transport of CO_2 between the liquefaction plant and the export facility.

Buffer storage

Buffer storage provides the flexibility needed to decouple the continuous arrival of CO_2 from capture plants from the intermittent nature of batch transport operations by ship or train. Buffer tanks were assumed to be installed at the loading terminals, storing CO_2 in the liquid phase at the same conditions adopted for transport (15 bar, –29 °C).

The storage capacity required at each terminal was determined by the expected transport capacity with a volume margin of +20% applied to accommodate operational variability, scheduling delays, and contingency requirements.

CAPEX for buffer storage was estimated at 1,200 €/tCO_2 of installed capacity, reflecting the cost of insulated pressure vessels suitable for medium-pressure liquid CO_2 service. OPEX is assumed to be 5% of CAPEX per year, covering inspection, maintenance, insulation integrity checks, and auxiliary systems such as boil-off management etc. Energy consumption associated with maintaining storage conditions was considered marginal compared to that of liquefaction and was therefore not included as a separate cost item.

2.2.1 Conventional ship

Conventional ship transport refers to the use of vessels that do not feature direct injection capabilities, meaning that CO_2 must be offloaded into intermediate storage or directly into a pipeline at the receiving terminal before being delivered to the storage site. These ships are purpose-designed for CO_2 transport under medium-pressure conditions (15 bar, –29 °C), with cargo capacities ranging from

10,000 to 50,000 tCO_2 per vessel. The appropriate ship size for each connection is determined by the CO_2 mass flow to be transported and the round-trip duration between the loading and unloading ports.

CAPEX

Ship CAPEX, which is strongly correlated with vessel size, was estimated using regressions provided by BREVIK based on the cost model developed as part of the joint industry project *CO_2 Logistics by Ship – Phase 3 (abbreviated the CO_2LOS-project)*[5]. The regressions capture the non-linear scaling of capital cost with cargo capacity, reflecting economies of scale typical of marine vessel construction.

OPEX

Ship operating costs include crew expenses, fuel consumption (MGO), harbour fees, maintenance, insurance, and management. The base values adopted in the assessment are summarised in Table 3.

Table 3. Main OPEX cost parameters considered.

	Value	Unit	Source
Crew costs	8,500	€/day	Adapted from Clarksons/CCSA report[6]
Fuel costs (MGO)	600	€/t	
Harbour fee 10,000 tCO_2 ship	~11,000	€	Adapted Element Energy / BEIS 2018 study[4]
Harbour fee 50,000 tCO_2 ship	~28,000	€	Adapted Element Energy / BEIS 2018 study[4]
SFOC	162–172	g/kWh	Calculated in function of engines power
Diesel CO_2 emissions	3.15	tCO_2/tDiesel	

Fuel consumption was determined as a function of engine power, specific fuel oil consumption (SFOC), and operating time, the latter being set by the ship's cargo capacity and sailing speed. Engine power requirements were derived from the demonstration cases produced by the Brevik/SINTEF cost application, accounting for both ship size and sailing speed.

Sailing speed was constrained to the range of 10–15 knots, with a default value of 10 knots. Higher speeds were only adopted where necessary to fine-tune a given connection, for instance, to reduce the number of ships required to serve a particular route.

Round-trip time was calculated as the sum of loading time, port exit, sailing time to the unloading site, unloading time, and the return sailing leg including port entrance.

Total connection costs

The total cost of a given connection was obtained by aggregating the CAPEX and OPEX of all the components involved: the ship or ships assigned to the route, loading and unloading equipment, buffer storage, and liquefaction. It is assumed that the selected ports already possess terminals suitable for equipment installation and ship docking; consequently, no costs for new terminal infrastructure or quay construction were included in the assessment.

The cost of CO_2 emissions associated with ship operation was not considered, on the assumption that such emissions can be mitigated through the future deployment of onboard CO_2 capture technologies or by switching to alternative, less carbon-intensive marine fuels.

Operational assumptions:

- Net cargo availability: 95% of total cargo capacity, accounting for vapour space, boil-off allowance, and the unpumpable heel remaining in the tanks after offloading.

[5] CLIMIT Project No. 618181.
[6] Georgie Wilson, *Clarksons/CCSA Report on Updated Costs for CO2 Ship Transport*, 2024.

- Annual availability: 90%, equivalent to 7,884 operating hours per year, reflecting scheduled maintenance, dry-docking, and unplanned downtime.
- Ship OPEX components: crew costs, maintenance, insurance, and management overheads, in addition to the variable fuel and harbour fees described above.

2.2.2 Ship with direct injection

Ships with direct injection were costed using the conventional-ship baseline, with additional CAPEX and OPEX added for onboard reconditioning and subsea injection equipment.

The direct injection system components and a high-level cost assessment were provided by NEMO Maritime and OneSubsea on a per-injection-rate basis (Table 4). The scope of this cost estimate includes the shipboard control system, the ship-to-riser connection system, and the onboard reconditioning equipment (heaters and pumps).

Table 4. CAPEX per injection rate for the direct injection system.

Injection rate (tCO_2/h)	CAPEX (€M)
<250	40
250-500	+20
500-750	+20

Onboard reconditioning

Before injection, the CO_2 cargo must be brought from ship storage conditions to the conditions required at the wellhead. Typical injection conditions considered in this study are 10–15 °C and 50 bar, which place the CO_2 in a dense-phase state suitable for stable downhole flow. Reconditioning consists primarily of pressurisation via booster pumps and controlled heating of the CO_2 stream. Where the local seawater temperature is sufficiently high relative to the cargo temperature, seawater is used directly as the heating medium through a dedicated heat exchanger, avoiding the need for an auxiliary heating loop and minimising additional fuel consumption. In colder regions or seasons where seawater alone is insufficient, a supplementary heating system is considered.

Dynamic positioning

During the connection and injection phases, the ship must remain on station above the subsea injection point, which requires dynamic positioning (DP) capability. The DP power demand and the associated fuel consumption is calculated based on the average sea conditions (wind, wave, and current) at each specific injection site (see Annex A).

OPEX drivers

For the direct injection scope, only two OPEX contributions are considered on top of the conventional-ship baseline: the energy required for both onboard reconditioning (pumping and auxiliary heating when needed) and dynamic positioning. Other potential cost items, such as periodic ROV inspections, riser hose maintenance, and subsea component overhauls, assumed to be either negligible at this level of assessment or covered by the storage operator.

Exclusions

The cost figures presented for direct injection cover only the shipboard reconditioning and injection equipment and the subsea interface up to the wellhead connection, as listed above. Items explicitly excluded from this scope are: the injection wells themselves, subsea manifolds and templates, reservoir characterisation and monitoring (MMV), permitting and regulatory costs, decommissioning,

and any onshore infrastructure. These elements are assumed to fall within the scope of the storage site operator and are accounted for separately under the storage tariff.

2.2.3 Pipeline

Pipeline transport was modelled following a four-step procedure:

- Route definition: Pipeline length is determined from the geographical layout of the network, accounting for the position of emitters, collection hubs, and storage sites, as well as terrain and routing constraints.
- Hydraulic sizing: Pipeline diameter is calculated as a function of CO_2 mass flow rate, route length, and operating conditions (inlet pressure, temperature, and allowable pressure drop).
- Cost estimation: CAPEX is derived from materials, labour, and other associated costs, scaled with pipeline length, diameter and types of terrain crossed.
- Energy assessment: Energy consumption for pumping and recompression, where applicable, is quantified based on the elevation and pressure profile along the route.

Operating conditions

Pipelines are assumed to receive CO_2 already pressurised at the capture site, delivered at 80 bar and ambient temperature. Under these conditions, CO_2 is transported in the dense phase, combining liquid-like density with gas-like viscosity. This enables high transport capacity, reduces compression energy per unit mass transported, and avoids two-phase flow regimes that would complicate pipeline operation.

Sizing

All pipelines are deliberately oversized by one level of standard size relative to the design CO_2 mass flow. A larger diameter reduces flow velocity and frictional pressure drop, lowering the pumping energy required to maintain dense-phase transport, at the cost of higher upfront CAPEX. The trade-off favours oversizing because pumping represents a recurring operational cost over the asset lifetime, a wider diameter provides hydraulic headroom to accommodate variability in capture rates and potential network expansions, and it reduces the need for intermediate booster stations. Pipelines are therefore sized for the maximum CO_2 mass flow expected over the full project horizon, rather than average or initial flow, avoiding costly retrofits as captured volumes grow.

Material selection

Pipelines are specified in carbon steel, API 5L grade X70, a high-strength low-alloy steel widely used in long-distance gas and CO_2 transport infrastructure. X70 offers a favourable balance between mechanical strength, weldability, and cost, and is suitable for the operating pressures considered (typically 80–150 bar), provided that CO_2 purity specifications are met. In particular, water content must be kept well below saturation to prevent the formation of carbonic acid and associated internal corrosion.

Cost model

Pipeline CAPEX is estimated as a function of length and diameter, with diameter determined through hydraulic sizing based on mass flow rate and pressure requirements. The cost build-up comprises three components: materials — primarily the steel pipe, scaled with diameter, wall thickness, and length, assuming a steel price of 1,800 €/t; labour — covering trenching, welding, laying, and commissioning; and other costs — including right-of-way acquisition, engineering, project management, valves, and monitoring systems.

Routing and terrain

Pipeline routes were generally designed manually using satellite imagery. However, in the Portuguese region routes were generated using a least-cost path algorithm, that assigns cost weights to four input layers — slope, land use, transport infrastructure, and protected areas (to be avoided by the route) — penalising alignments that traverse costly or constrained terrain.

Baseline costs are scaled from the steel price and labour assumptions above and further adjusted using terrain correction factors for topography, land use, special crossings, and onshore vs. offshore segments. Offshore routes were calculated as straight-line distances and costed at 1.5 times the onshore baseline. Where elevation data was available, terrain slope was incorporated into both the pressure profile and the cost correction. Each factor is applied only to the pipeline length traversing that terrain type, with land use and slope factors applied cumulatively where they overlap. The correction factors are summarised in Table 5.

Table 5. Terrain and land use cost correction factors.

LAND USE	Weight	SLOPE	Weight
Unpopulated	1.0	<10%	1
Urban and associated areas	1.8	10-20%	1.1
Cultivated land	1.1	20-30%	1.2
Forest	1.3	30-70%	3.0
Bare areas	1.1	>70%	9.0
Regularly flooded	1.2		
Water bodies	4.0		
		CROSSINGS	**Weight**
Offshore	1.5	Roads, Pipelines, Railways	3.0

2.2.4 Train

CO_2 transport by rail was modelled using wagons with a capacity of 50 tCO_2, based on standard 60 m^3 tank wagons suitable for liquid CO_2 at typical rail transport conditions of approximately –30 °C and 15 bar. Train frequency and composition were sized to maintain a continuous CO_2 flow from the capture site to the destination terminal, thereby minimising the required buffer storage capacity at both ends of the journey. This operating logic favours a steady-state logistics regime over batch deliveries, reducing intermediate storage costs while ensuring alignment with the upstream capture rate and downstream injection or shipping schedule.

2.2.5 Barge

No dedicated cost model is available for barges, so the same cost model used for ships was applied, given that ship cost correlates strongly with capacity. Although the ship cost model was originally developed for vessels in the 10,000–50,000 tonne range, it is assumed that this correlation with capacity would hold when extrapolated to smaller units.

Barge capacity was set in line with typical European inland barges, which generally carry between 1,500 and 3,000 tonnes. Crew costs were assumed at 4,000 €/day and fuel costs at 1,200 €/t.

2.3 Storage

The storage cost evaluation builds on the reservoir characteristics — including depth, permeability, porosity, thickness, and initial pressure — to determine the required wellhead injection pressure, the injectivity and, consequently, the number of wells needed to accommodate the targeted CO_2 flow rate. These reservoir-driven parameters are combined with a set of standardised cost items to derive CAPEX and OPEX.

On the CAPEX side, the assessment includes well drilling costs, which scale with well depth and the number of wells required; plug and abandonment (PnA) costs, accounting for the eventual permanent sealing of each well at the end of the project life; surface infrastructure startup costs, covering the topside facilities needed to receive and distribute the CO_2 to the injection wells; and seismic campaign costs, covering the geophysical surveys required for site characterisation and baseline definition prior to injection.

On the OPEX side, well maintenance costs are applied on a per-well, per-year basis to reflect routine integrity management and workover activities, while a flat cost is added to consider site operation, monitoring, reporting, and overheads that are largely independent of injection volume.

Three transport-to-storage configurations are evaluated, each with a distinct set of cost items allocated to the storage side. In the pipeline scenario, CO_2 is delivered continuously to the injection site through an offshore pipeline, and an umbilical is required to provide power, control, and chemical injection services to the subsea equipment; this umbilical cost is included within the storage CAPEX. In the conventional ship-to-platform scenario, CO_2 is delivered by shuttle ships to an offshore platform that handles reconditioning and injection into the wells; in this case, the platform itself — including its topside facilities and the associated offloading interface with the shuttle ships — is accounted for under the storage costs. In the direct ship injection scenario, the shuttle ship connects directly to the subsea infrastructure without an intermediate platform, and the cost of the ship-to-subsea connection system (riser, riser bed, hose swivel, jumper, subsea control module, and umbilical connection) is allocated to the storage side. In all three scenarios, the reservoir-driven items described above — well drilling, PnA, surface infrastructure startup, seismic campaigns, well maintenance, and flat administrative costs — remain common to the storage tariff, while the scenario-specific interface costs are added on top to reflect the chosen transport-storage configuration.

2.4 Scenarios and integrated cost evaluation

The regions under study are geographically diverse, and the scenarios developed for each also differ in scope and context. For this reason, results are presented in the format that best suits each region, rather than forced into a single normalised structure.

Because the underlying cost components are drawn from different sources and estimation methods, some inconsistency in granularity across the chain is unavoidable. Overall results are expected to fall within the accuracy range of an AACE Class 4 estimate, typically −30% to +50% relative to actual cost.

2.4.1 Structure of the reported results

Results are reported at two levels:

- **Per CCS component,** covering capture, transport, and storage individually.
- **Full-chain costs,** integrating all components into a scenario-level assessment.

Capture

Results for the capture component are presented at a general level, focusing on the additional CO_2 emissions associated with the capture process and on overall costs. Capture costs are not broken down per emitter or industrial sector, as this lies outside the scope of the study.

The capture assessment was nonetheless necessary for two reasons:

- It accounts for the additional emissions generated by the capture process itself, which directly affect the volumes of CO_2 to be transported and stored.
- It enables a more accurate determination of the mass of CO_2 abated.

Transport and storage

Results for transport and storage are presented in two parts: first, a technical description of the solutions considered for each scenario; second, the corresponding cost estimates. Reported figures correspond to Bare Erected Cost (BEC) in €2030, mostly excluding contingencies, insurance, and financing-related costs. They therefore represent the underlying technical costs.

Integrated cost assessment

All costs are reported as Net Present Costs (NPC) in €2030, computed in two steps: each cost item is first inflated to the year in which it is disbursed, and then discounted back to 2030 using a 5% discount rate.

Inflation

Costs taken from the literature are expressed in their source-year currency and escalated to the year of expenditure using regional inflation rates (2.5% for the Atlantic coast, 4% for the Baltic Sea, North Sea, and Black Sea regions; see regional assumptions in section 2.5). Non-euro sources, such as the Shipping CO_2 – UK Cost Estimation Study, reporting in 2018 GBP, are first converted to euros at the 2018 exchange rate before being escalated.

CAPEX phasing

CAPEX is not treated as a single overnight cost. Each investment item — capture plant, pipeline, ships, wells, platforms — is placed in the specific year(s) it is disbursed, according to equipment type and scenario. Reinvestment for equipment is not included since most equipment are expected to last through the duration of the scenarios.

OPEX

Operating costs are incurred annually over each region's scenario specific operating, inflated at the regional rate, and discounted back to 2030 (Table 6). Romania, Ukraine and the North Sea use 2035–2065; Baltic and Portuguese facilities enter service in phases, from 2031 and from 2035, respectively, and operate to 2065.

Because inflation is applied in the cost build-up and the discount rate on top, the effective real discount rate is approximately 2.4% for the Atlantic coast and 1.0% for the other regions. This relatively low real rate gives long-term OPEX a noticeable weight in the final NPC.

Specific cost per tonne of CO_2 abated

The specific cost is obtained by dividing the NPC by the total undiscounted mass of CO_2 abated over the operating life. CO_2 volumes are treated as physical quantities and are not discounted, so each tonne is counted equally regardless of the year of abatement. The result is expressed in €2030 per tonne of CO_2 abated.

Table 6.Global parameters used in all regions.

Parameter	Value
Reference year	2030
CCS first year	2035*
CCS last year	2065
Operation years	31

* Some Baltic facilities begin operations in 2031 as the first year and run until 2065.

Specific costs of CO_2 per tonne abated

Specific costs are expressed per tonne of CO_2 abated, defined as:

$$CO_2 \text{ abated} = CO_2 \text{ avoided} + CO_2 \text{ removed}$$

where *CO_2 avoided* refers to emissions that would otherwise have been released from a fossil or industrial source but are captured and permanently stored, and *CO_2 removed* refers to atmospheric or biogenic CO_2 that is durably removed from the carbon cycle via BECCS.

2.4.2 Exclusions

Consistent with the scope of this assessment, the **NPC does not include**:

- the cost of capital or any specific financing structure (only the 5% project discount rate is applied);
- annualised capital recovery factors (CAPEX is included as actual disbursements, not as an annuity);
- contingencies beyond standard project operations, insurance, and decommissioning costs;
- revenues from CO_2 pricing or other support mechanisms.

2.5 Regional assumptions

The input parameters fed into the tool differ for each regional scenario. This will be described in the region chapters the text, but an overview is provided in Table 7.

Table 7. Regional assumption values.

Parameter	Baltic Sea	North Sea	Black Sea Romania	Black Sea Ukraine	Atlantic coast	Unit
Electricity price	87	100	87	105	78.7	*€/MWh*
Electricity CO_2 emissions	170	30	229	1,084	13*	*gCO_2e/kWh*
Inflation	4	4	4	4	2.5	*%*
Discount rate	5	3	5	5	5	*%*
Natural gas price	600	426	426	426	750	*€/t*
Seismic campaigns	6	4	6	6	6	-
Seismic campaign cost	10	103	10	12	10	*€M*
Well drilling[7]	26.8	20.0–40.0	23.3–26.8	26.8	23.3	*€M*
Well plug and abandonment	6.4	6.4	6.4	6.4	6.4	*€M*

*Values for Portugal were considered to decrease from 56 g/kWh in 2035 to 0 g/kWh in 2065. With the average value for that time interval being 13 g/kWh.

[7] Midtgaard, H., Miriyev, A., Neugebauer, M., & Petersen, R. (2025). CTS D4.1—Well Designs & Cost Estimates.

3 Baltic Sea

The Baltic scenario brings together the main industrial sources in Estonia, Latvia and Lithuania with a shared offshore storage solution in Latvia. The system relies on the combination of pipeline and maritime transport to connect dispersed emitters to the E6 structure (Figure 2). The transport configuration reflects the geographical distribution of emissions in the region and provides a practical basis for the coordinated development of CCS across the Baltic countries, allowing CO_2 stream to be progressively integrated as capture is deployed.

The following sections describe and update the scenario previously defined in D2.1[8] by considering higher CO_2 capture volumes as a result of excluding CO_2 use options and including extra industrial sources, including sources producing biogenic CO_2.

3.1 Scenario overview

Since the production of the scenario in D2.1, the regulatory framework for CCS has been clarified, with a more positive context for the storage of CO_2 in the Baltic Sea. On 9th October 2025, the Latvian Parliament approved amendments to the Law on Pollution, lifting the ban on permanent CO_2 storage in geological formations. This follows another major milestone on 3rd April 2025, when the Latvian Parliament amended the Law on Subterranean Depths, setting out key elements for geological CO_2 storage, including site exploration, licensing, operation, closure, and long-term stewardship. These amendments, which entered into force on the 1st July 2025, also require the Cabinet of Ministers to develop detailed regulations on operator responsibilities, third-party access, and dispute-resolution procedures. After these changes, it can be said that Latvia transposed the EU CCS Directive in full capacity, ensuring safe and regulated CO_2 storage[9].

The Baltic scenario involves CO_2 capture in industrial sources from Estonia, Latvia, and Lithuania, transport by onshore pipelines and ship to offshore CO_2 storage site in Latvia, at the E6 structure, in the sandstone reservoir of the Cambrian Wuliuan Deimena Formation. CO_2 capture is organised into regional clusters: Estonian cluster; Latvian cluster, and Latvian–Lithuanian cluster.

These clusters include 16 emitters from multiple industrial sectors, including power generation, shale oil production, cement, refining, ammonia production, waste-to-energy, and paper industries. With respect to the preliminary scenario in D2.1, the mass of CO_2 available to be captured, transported and stored has been revisited given that:

- a 0.9 $MtCO_2/yr$ CO_2 utilisation option considered in D2.1 has been discarded;
- the time frame for deployment of CO_2 capture was set to 2031 for Latvian and Lithuanian cement plants, 2035 for power plants, shale oil and chemical plants, and 2040 for Waste-to-energy and paper plants, mainly producing bio-emissions.

The transport system is a multimodal network. CO_2 will be transported by pipelines to four ports, and then by ships from the ports to the E6 storage site. The planned storage site is in the Cambrian Wuliuan Deimena Formation sandstone reservoir, in offshore Latvia at a depth of more than 850 m. A 53-meter-thick sandstone reservoir is covered by 46-meter-thick shales as the primary cap rock of the Lower

[8] Shogenova, A., Shogenov, K., & Usta, M. (2025). CTS D2.1—Report on clusters created.
[9] Bellona EU. (2025, October 9). Latvian Parliament lifts ban on CO2 storage in geological formations. https://eu.bellona.org/2025/10/09/latvian-parliament-lifts-ban-on-co%E2%82%82-storage-in-geological-formations/ (Accessed 4/08/2026).

Ordovician Zebre Formation, and by Ordovician and Silurian about 300-m-thick secondary clayey carbonate cap rocks.



Figure 2. Baltic offshore cross-border scenario. The transparent yellow circles represent the clusters and sub-clusters. Estonian Cluster (1), with Ida-Viru (northeastern) sub-cluster leading to Sillamäe Port and Tallinn-Harju sub-cluster connected to Muuga Port. Latvian Cluster: (2) associated with the Riga Port. Latvian-Lithuanian Cluster linked to Klaipeda Port: (3).

3.1.1 CO_2 Capture

The Baltic Sea scenario is organised into three main regional clusters, grouping emitters based on geographic proximity and access to transport infrastructure (Figure 2).

Estonian Cluster

The Estonian cluster is divided into two sub-clusters:

(1) ***Ida-Viru sub-cluster (North-East Estonia):*** It includes five large emitters (power plants and shale oil facilities), which produced in 2023 about 3.5 $MtCO_2$. This sub-cluster represents the largest concentration of emissions in the Baltic region.
(2) ***Tallinn-Harju sub-cluster***: Includes three emitters (energy and waste-to-energy facilities), which produced in 2023 about 0.43 $MtCO_2$.

Thus, the total CO_2 available for capture in Estonia is 3.92 $MtCO_2$/yr. CO_2 capture will start in 2035 at the Utilitas Tallinn Power Plant and in 2040 at the Horizon Paper Factory and Iru Waste-to-Energy plants, and will be completed in 2065 by all plants. These sub-clusters are connected to the ports of Sillamäe and Muuga via dedicated pipeline systems.

Latvian Cluster

The Latvian cluster consists of two major power plants (TEC-1 and TEC-2), which produced in 2023 about 0.7 $MtCO_2$. These facilities are connected to the Port of Riga via pipeline infrastructure.

Latvian–Lithuanian Cluster

This cluster is composed of four sub-clusters (West Lithuanian, North-Lithuanian, Latvian and Kaunas) with six emitters across multiple sectors, including cement production, oil refining, ammonia production, and waste-to-energy. Total CO_2 produced in the Latvian-Lithuanian Cluster in 2023 was 4.76 Mt. The cluster is connected to the Port of Klaipėda, which serves as the main maritime hub for this region.

Figure 3 and Figure 4 show the distribution of CO_2 emissions per source, type and per cluster / country.

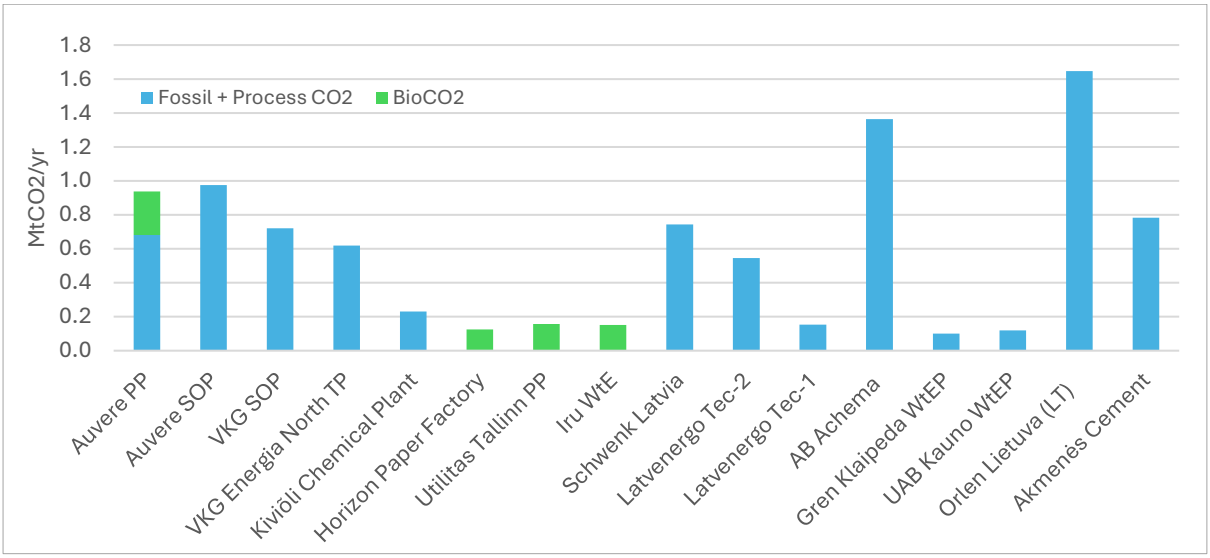


Figure 3. Emissions considered for capture and storage per industrial facility for the Baltic scenario.

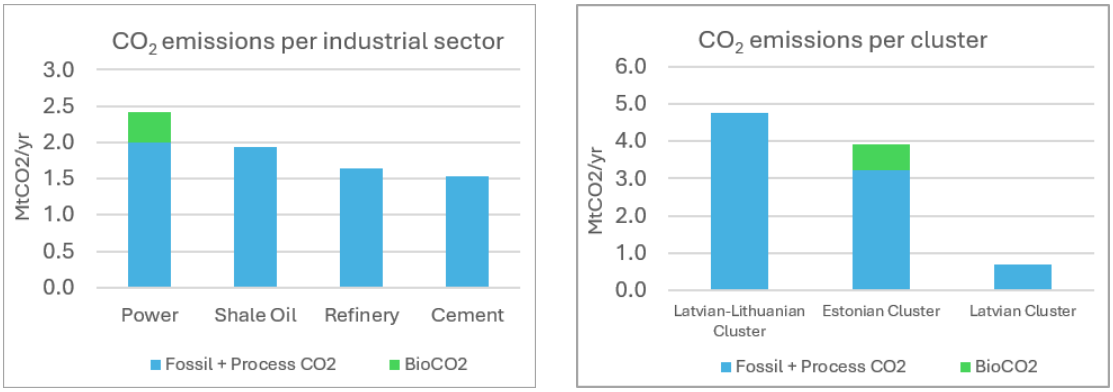


Figure 4. Emissions considered for capture and storage per industrial sector and per cluster for the Baltic scenario.

Total CO_2 produced in the Baltic Scenario in 2023 is 9.38 Mt, and unlike in the scenario developed in D2.1[8], the CO_2 use option was not considered, increasing by 0.9 $MtCO_2$/yr the amount of CO_2 available for storage. CO_2 capture deployment is phased between 2031 and 2040, enabling gradual integration of emitters into the CCS network.

3.1.2 CO_2 Storage site

The Baltic scenario relies on the E6 offshore geological structure in the Latvian sector of the Baltic Sea as the primary CO_2 storage site (Figure 5). The Cambrian Wuliuan Deimena Formation sandstone reservoir in the E6 structure offshore Latvia is at a depth of more than 850 m. A 53-meter-thick sandstone reservoir is covered by 46-meter-thick shales as the primary cap rock of the Lower Ordovician Zebre Formation and Ordovician and Silurian about 300-m thick secondary clayey carbonate cap rocks. The presence of a 10 m-thick oil layer in the Upper Ordovician Saldus Formation provides additional evidence of the E6 structure's excellent sealing properties.

The reservoir in the Cambrian Wuliuan Deimena Formation (848–901 m depth at the well E6-1/84) in the E6 structure is assessed as the largest storage site among all the structures studied for CO_2 storage in the Baltic Region and it represents one of the most advanced and well-characterised CO_2 storage sites in the Baltic region. It is considered a key enabler for cross-border CCS deployment. The storage capacity of the E6 structure was quantified for two distinct compartments, designated as Part A and Part B. Conservative and optimistic average CO_2 storage capacity of the Deimena Formation sandstone reservoir in Part A was estimated at 146–365 million tonnes (Mt), respectively (Table 8). The CO_2 storage capacity of the total Cambrian reservoir (parts A and B) is 152–377 Mt[10], since the part B compartment has residual storage capacity. The estimated optimistic storage capacity of approximately 365 $MtCO_2$ was considered for the Baltic Scenario, in the Part A compartment, which is hereafter referred to as E6-A.

[10] Shogenov, K., Shogenova, A., & Vizika-Kavvadias, O. (2013). Potential structures for CO2 geological storage in the Baltic Sea: Case study offshore Latvia. Bulletin of the Geological Society of Finland, 85(1), 65–81.

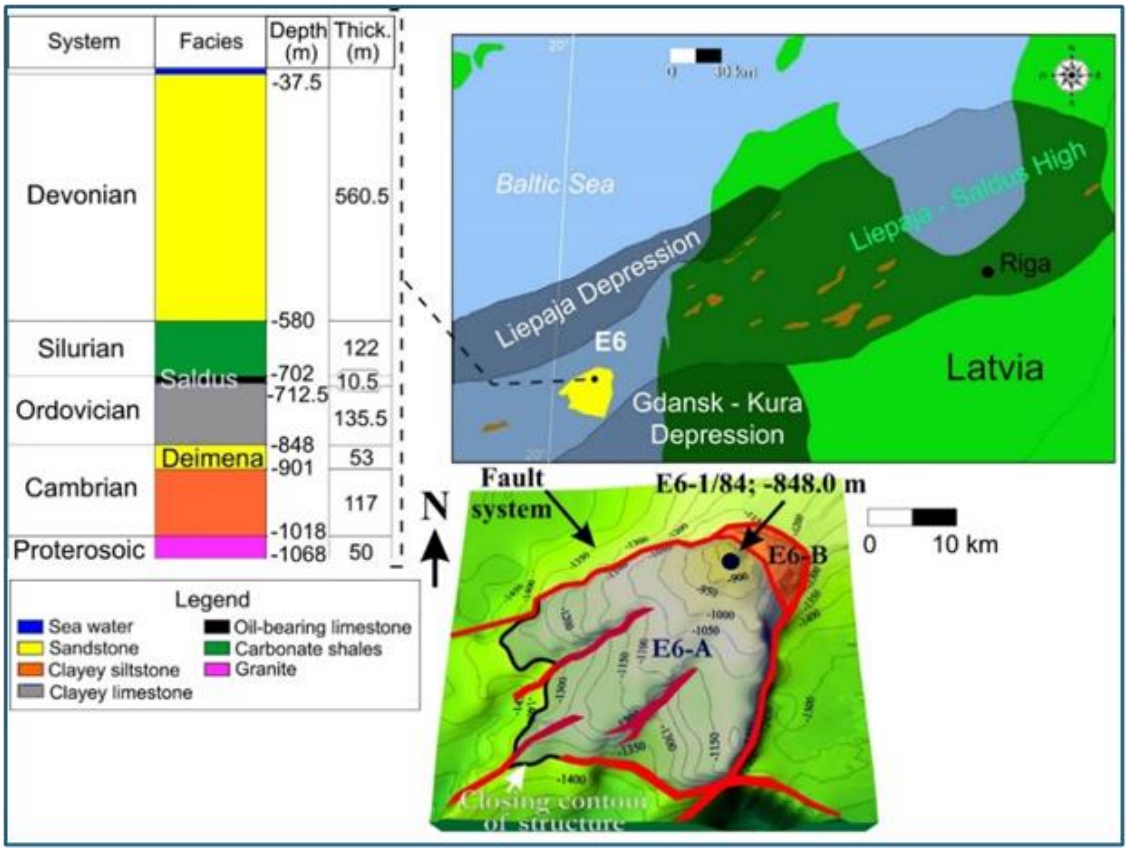


Figure 5. The E6 Latvian offshore underground geological structure, prospective for CO_2 storage in the Cambrian aquifer (yellow), with the location of the well E6-1/84 (red dot) and lithological cross-section, and the 3D geological model of the top of the Cambrian Deimena Formation of the E6 structure. The smaller E6-B compartment is indicated by transparent red[11], [12].

Table 8. Reservoir parameters of the Deimena Formation sandstone reservoir in the CO_2 storage site E6-A selected for the Baltic scenario.

Parameters E6	Value	Unit
Depth of reservoir top [a]	848-901	m
Reservoir thickness	53	M
Trap area	553	km^2
Net to gross ratio	90	%
CO_2 density	658	kg/m^3
Salinity	99	g/L
Permeability[c]	10-440 (160)	mD ($10^{-16}m^2$)
Porosity[c]	14-33/21	%
Temperature	36	°C
Storage efficiency factor[b]	10/4	%
Optimistic CO_2 storage capacity[c]	243-582/365	Mt
Conservative CO_2 storage capacity[c]	97-233/146	Mt

[a] (min-max); [b] (Optimistic/Conservative); [c] (min-max/avg.)

[11] Shogenov, K., Shogenova, A., Gei, D., & Forlin, E. (2017). Synergy of CO2 storage and oil recovery in different geological formations: Case study in the Baltic Sea. Energy Procedia, 114, 7047–7054. https://doi.org/10.1016/j.egypro.2017.03.1846.
[12] Shogenov, K., & Shogenova, A. (2021). Innovative synergy CCUS and renewable energy project offshore Baltic using CO2 emissions from the cement industry. In 15th International Conference on Greenhouse Gas Control Technologies (GHGT-15). Elsevier. https://doi.org/10.2139/ssrn.3812387.

Table 9. Characteristics of CO_2 emitters and distances to ports and from ports to the E6 storage site.

Country and Cluster		N	Plant Name	Region/Town	Sector	CO_2 emitted in 2023, tCO_2/yr	Pipeline distance to Port (km)	Ship Distance from port to E6, km
ESTONIA	**Ida-Viru (NE) cluster to Sillamäe port**	1	Auvere PP	Ida-Viru /Auvere	Power	937 197	**25.2** (From SOP to the port, **1.3 km** between Auvere plants along the road, **26.5 km in total**)	
		2	Auvere SOP	Ida-Viru /Auvere	Shale Oil Plant	975 506		
		3	VKG SOP	Ida-Viru /Kohtla-Järve	Shale Oil Plant	721 077	**19.8** (from SOP to the port, **1 km** between VKG plants using railway, **20.8 in total**)	
		4	VKG Energia North TP	Ida-Viru /Kohtla-Järve	Power	619 974		
		5	Kiviõli Chemical Plant	Ida-Viru/ Kiviõli	Shale Oil Plant	231 536	**37.3** (from the plant to VKG hub, from VKG hub **19.8 km**. **In total 57.1 km**)	
					Total	**3 485 290**	**84.6**	751
	Tallinn-Harju cluster to Muuga Port	6	Horizon Paper Factory	Harju/Kehra	Paper	125 341	**32.7**	
		7	Utilitas Tallinn PP	Harju/Tallinn	Power	156 219	**3.7** (from the plant to Iru WtE)	
		8	Iru WtE	Mardu/Iru	WtE	151 776	**9.6** (from the plant to port)	
		Total				**433 336**	**46**	575
					Total for Estonian clusters	**3 918 626**	**150.4**	
Latvian Cluster (Riga port)		1	Latvenergo Tec-2	Salaspils	Power	546 285	**15.1** (from Tec-2 to Tec-1)	
		2	Latvenergo Tec-1	Riga	Power	154 079	**7.5** (from Tec-1 to port)	
					Total for Latvian Cluster	**700 364**	**22.6**	402

Country and Cluster		N	Plant Name	Region/Town	Sector	CO_2 emitted in 2023, tCO_2/yr	Pipeline distance to Port (km)	Ship Distance from port to E6, km
Latvian - Lithuanian Cluster (Klaipeda Port)	West Lithuanian sub-cluster	1	Gren Klaipeda WtE	Klaipeda	WtE	100 151	**11.2** (from Gren WtE to Port)	
	North Lithuanian sub-cluster	2	Orlen Lietuva (LT)	Telšiai	Refinery	1 646 257	**116** (Orlen LT to Gren Klaipeda WtE)	
		3	Akmenės Cement	Akmene	Cement	783 849	**51.23** (Akmenes Cementas to Orlen LT)	
	Latvian sub-cluster	4	Schwenk Latvia	Saldus/Broceni	Cement	744 135	**73.44** (from Schwenk to Orlen)	
	Kaunas sub-cluster	5	AB Achema	Jonavos Region	Ammonia	1 363 398	**230.5** (from Achema to Klaipeda Port)	
		6	UAB Kauno WtEP	Vilnius	WtE	119 661	**95** (from UAB Kauno to Achema)	
		Total for Latvian - Lithuanian Cluster				**4 757 451**	**577.37**	90.5
Total for Baltic Scenario						**9 376 441**	**730.57**	**1818.5**

3.1.3 CO_2 Transport

The transport system is designed as a multimodal network that combines onshore pipelines and maritime transport with conventional ship and direct injection from ship (Figure 2 and Table 9). The onshore component is constant in the TEA analysis, but the offshore component, although always by ship, considers the possibility of using ships with direct injection capability.

Pipeline Transport

CO_2 is transported from industrial emitters to four regional ports through a network of pipelines covering a total distance of approximately 730 km:

- In NE Estonia, around 84.6 km of pipelines are required to transport CO_2 to NE Sillamäe Port.
- In the Tallinn-Harju cluster, 46 km of pipelines are needed to transport CO_2 to Muuga Port (part of Tallinn Port).
- From the Latvian cluster, CO_2 produced by two Latvenergo Natural Gas power plants will be transported to Riga Port via 22.6 km of pipelines.
- In the Latvian-Lithuanian cluster, CO_2 captured by Schwenk Cement Latvia in Broceni and by 6 plants in Lithuania will be transported via 577.4 km of pipelines to Klaipeda.

Maritime Transport

From four Baltic ports, CO_2 is to be transported to the E6 Latvian offshore storage site via approximately 1818.5 km of shipping routes. Key transport routes include: (1) from the port of Sillamäe to the E6 (751 km), (2) from the port of Muuga to the E6 (575 km), (3) from the port of Riga to the E6 (402 km), (4) from the port of Klaipėda to the E6 (90.5 km). Table 9 indicates the main transport distances between clusters, ports and the storage site.

Two alternative scenarios are considered, a first one designated **SHIP scenario** in which the maritime transport is made using conventional ships that offload to a platform from which injection is conducted; and alternative scenario in which it is admitted that ships with capability to connect to the well and conduct direct injection are used – **DSI scenario**.

It should be noted that in Lithuania, KN Energies located in Klaipeda Port, already signed FEED (front-end engineering and design) contract with Aker Solutions for construction of multimodal LCO_2 import/export terminal in the Port of Klaipeda, as a part of the EU PCI–CCS Baltic Consortium – (cross-border CO_2 transport via pipeline and rail/truck between Latvia and Lithuania with a multi-modal LCO_2 terminal based in Klaipeda)[13],[14]. The final investment decision will be made by the end of 2027. The CO_2 terminal is expected to begin commercial operations in 2030[15].

3.2 Techno-economic assessment results

3.2.1 Capture

Figure 6 shows the expected annual amount of CO_2 captured at each facility in the Baltic Sea region, including the additional CO_2 generated by the capture process itself and assumed captured along with the flue-gas CO_2. Deployment unfolds in three phases, at 5-year intervals for ease of analysis. Three

[13] CCS Baltic - CCS Baltic Consortium project.

[14] FEED agreement signed for the planned CO_2 transshipment terminal in Klaipėda - CCS Baltic Consortium project.

[15] KN Energies signs Grant Agreement with the European Commission - CCS Baltic Consortium project.

facilities start in 2031, the network expands to 12 facilities in 2035, and all 16 are operating from 2040 onwards. All facilities remain capturing CO_2 until 2065.

At full deployment 11.13 $MtCO_2$/yr is captured - higher than the underlying industrial baseline due to the emissions resulting from the capture process. Capture is heavily concentrated in four large sources that account for about 5.95 $MtCO_2$/yr, just over half of the total. Identification of sources and scenario values are provided in Table 9 and Figure 6.

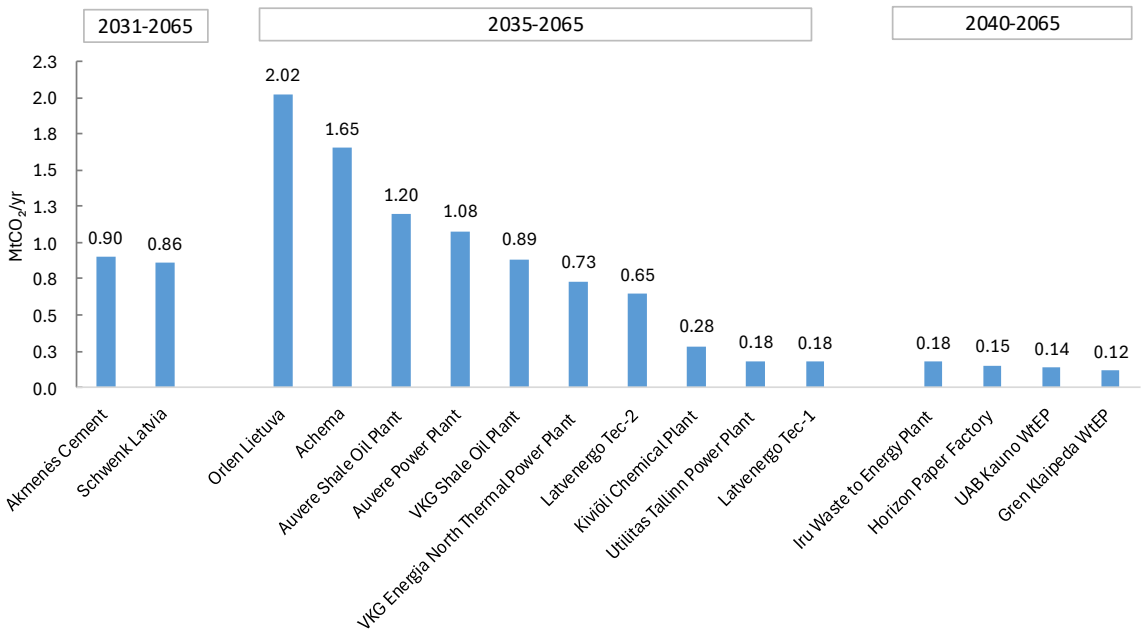


Figure 6. Baltic Sea. Annual CO_2 mass captured per emitter.

Considering the current emissions and over the scenario timeframe (2031–2065), the 16 industrial facilities would release 294.3 $MtCO_2$ to the atmosphere in a no-CCS baseline. With CCS, and across the scenario period, a total of 351.8 $MtCO_2$ is captured and permanently stored, of which 72.2 $MtCO_2$ corresponds to process emissions from the capture step. From the total amount stored, 18.8 $MtCO_2$ is biogenic CO_2. Residual uncaptured emissions from the 16 industrial facilities fall to 14.7 $MtCO_2$ over the full period, implying an emission reduction of 279.6 $MtCO_2$ at the capture stage (Table 10).

Table 10. Baltic Sea. CO_2 mass balance from the CCS chain at the capture stage.

CO_2 mass balance (2031–2065)		
Baseline industrial emissions (no CCS)	294.3	$MtCO_2$
CO_2 captured	351.8	$MtCO_2$
Biogenic CO_2 captured	18.8	$MtCO_2$
Process emissions from capture	72.2	$MtCO_2$
CO_2 stored	351.8	$MtCO_2$
Net industrial emissions with CCS	14.7	$MtCO_2$
Emission reduction (vs baseline) at the capture stage	279.6	$MtCO_2$

3.2.2 Transport

3.2.2.1 Scenario I – Conventional CO_2 ship (SHIP)

Pipeline CO_2 transport

The onshore network combines short feeder lines with long connections to the four export ports, with individual throughputs ranging from 0.1 to 5.7 $MtCO_2$/yr. The principal design requirement is to

maintain dense-phase conditions across this heterogeneous network; additional pumping is required only on the longer segments. Table 11 reports the dimensions, pressures and cumulative flows for each connection.

Table 11. Baltic Sea. SHIP scenario pipelines characteristics.

	Range	Unit
Total CO_2 transported per pipeline (scenario)	3.6—182.2	*Mt*
Annual CO_2 transported per pipeline	0.1—5.7	*$MtCO_2/yr$*
Outside diameter	127—508	*mm*
Inside diameter	114.5—482.6	*mm*
Wall thickness	6.3—12.7	*mm*
Booster compression	20	*bar*
Inlet pressure	100	*bar*
Outlet pressure	88.4—99.2	*bar*

Total capital expenditure reaches approximately 561.8 €M, of which 555.3 €M corresponds to the pipelines and 6.5 €M to pumping equipment (Table 12). Operating costs amount to around 15.2 €M/yr, split between 13.5 €M/yr for the pipelines and 1.7 €M/yr for pumping. Pipelines are therefore the principal cost driver across both investment and operating expenditure, while pumping plays a secondary, but relevant role due to the long distances involved.

Table 12. Baltic Sea. CAPEX and OPEX of pipelines. (Values are undiscounted and represent costs in 2030 terms).

	Pipelines	**Pumping**	
CAPEX	555.3	6.5	€M
OPEX	13.5	1.7	€M/yr

Conventional ship CO_2 transport

Four routes connect Sillamäe, Muuga, Riga and Klaipėda to the E6 storage site. Vessel capacity and sailing frequency are determined by the combination of route distance and annual CO_2 flow: S#01 is the longest connection, whereas S#04 is the shortest but carries the largest annual volume. Loading, unloading and buffer-storage capacities were sized to maintain route continuity and comply with the injection constraints. The detailed parameters are provided in Table 13.

Table 13. Baltic Sea. Conventional ship CO_2 transport characteristics.

Ship	S#01	S#02	S#03	S#04	*Unit*
Total CO_2 transported	129.60	14.28	25.66	182.21	*Mt*
Max. CO_2 transported	4.18	0.51	0.80	5.7	*$MtCO_2/yr$*
Sailing distance	751	575	402	91	*km*
Number of ships	2	1	1	2	
Ship size	50,000	8,000	12,000	30,000	*tCO_2*
Loading rate	2,500	2,500	2,500	2,500	*tCO_2/h*
Unloading rate	600	250	250	750	*tCO_2/h*
Sailing speed	14	10	11	14	*knot*
Number of roundtrips	45	68	73	108	*per year*
Buffer storage	114,000	9,120	13,680	34,200	*tCO_2*

SHIP requires approximately 1,475.1 €M of transport CAPEX and 87.9 €M/yr of OPEX. Vessel acquisition dominates the investment, while liquefaction and ship operation are the main recurring

costs. The configuration therefore combines a vessel-led initial investment with operating expenditure driven by CO_2 conditioning and maritime transport (Figure 7).

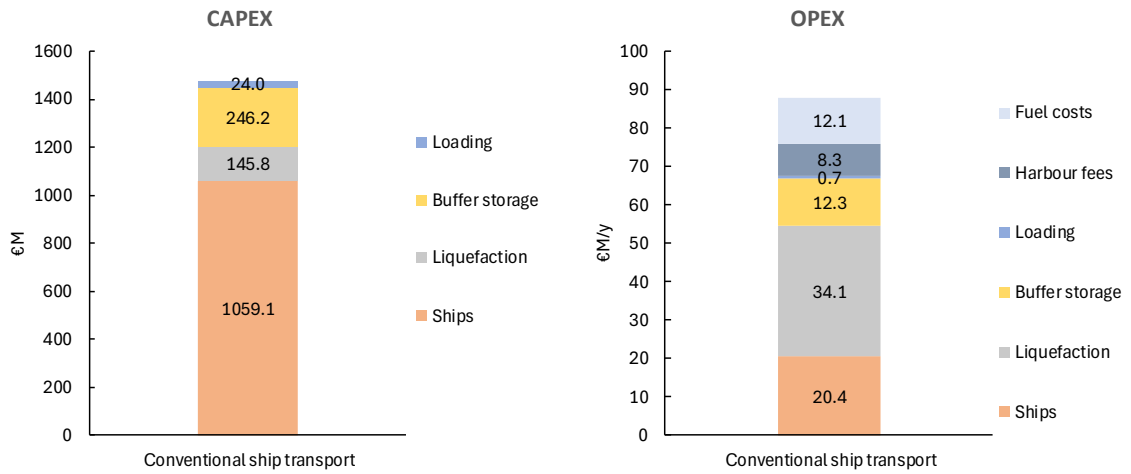


Figure 7. Baltic Sea. CAPEX and OPEX of SHIP scenario. (Values are undiscounted and represent costs in 2030 terms).

3.2.2.2 *Scenario II – Direct ship injection (DSI)*

The Direct Ship Injection (DSI) scenario removes the fixed offshore unloading platform but requires additional equipment on the vessels for CO_2 reconditioning and injection. Transport CAPEX increases to approximately 1,875.1 €M and OPEX to 111.9 €M/yr, with the difference relative to SHIP concentrated in unloading equipment and fuel. DSI therefore shifts expenditure from fixed storage infrastructure to the maritime transport and injection system (Figure 8).

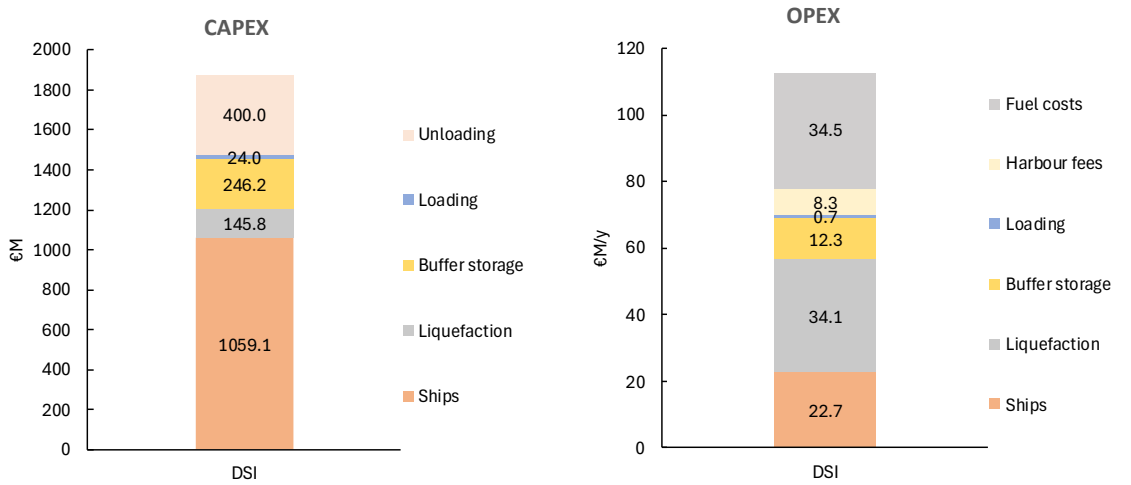


Figure 8. Baltic Sea. CAPEX and OPEX of DSI scenario. (Values are undiscounted and represent costs in 2030 terms).

3.2.3 Storage

In the Baltic Sea case, CO_2 storage is allocated to a single storage unit (SU#01), with sufficient capacity to accommodate the 351.8 $MtCO_2$ injecting over eight wells (Table 14). Assuming continuous operation, the per-well injection rate is 160 tCO_2/h, while in batch-injection, this injection rate will increase to around double or more, depending on the duty cycle.

Table 14. Baltic Sea. Storage parameters.

	E6 (SU#01)	Unit
Annual injection rate	11.21	*$MtCO_2/yr$*
Total CO_2 stored	351.8	*$MtCO_2$*
Number of injection wells (active)	8	
Average injection rate per well (if continuous)	160	*t/h*

The two configurations use the same storage unit, eight injection wells and seismic programme. The cost difference is therefore limited to offshore infrastructure: SHIP requires a permanent receiving platform and has storage CAPEX of 851.2 €M, whereas DSI reduces this to 451.2 €M by injecting directly from the vessels. Storage OPEX is identical at 22 €M/yr excluding energy. The storage comparison is consequently a choice between fixed platform infrastructure and direct offshore injection, rather than a difference in reservoir development (Figure 9).

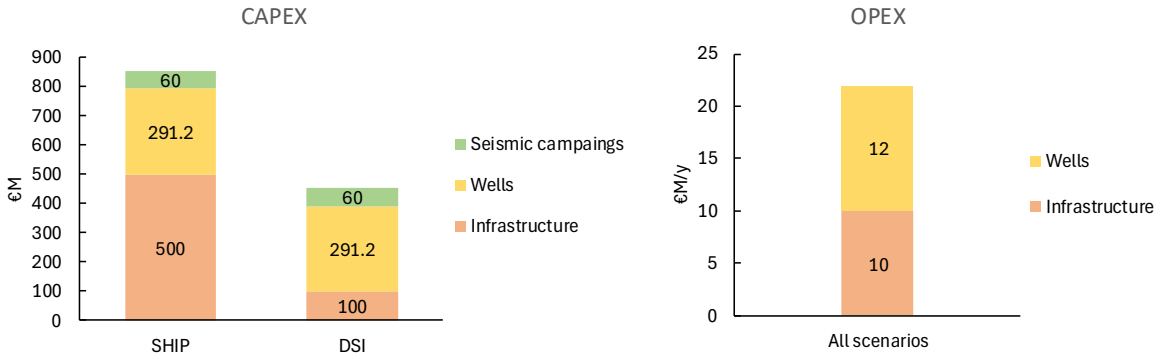


Figure 9. Baltic Sea. Storage costs excluding energy use. OPEX is identical across the two scenarios and is therefore shown as a single bar. (Values are undiscounted and represent costs in 2030 terms).

3.2.4 Energy consumption

Total energy demand is dominated by the CO_2 capture process, with the additional energy required for transport and injection being much smaller, and essentially identical in the two scenarios (Figure 10). Because both configurations rely on the same ship-based logistics, their transport energy profiles are effectively the same. The transport energy requirement is 25 kWh/tCO_2 stored..

Injection energy is required for both ship-based cases, since CO_2 delivered by ship requires additional conditioning before injection, and again values are similar (Figure 10) at roughly 12 kWh/tCO_2 stored. The transport and injection energy demand totals about 37 kWh/tCO_2 stored in both scenarios, driven by the combined effect of upstream liquefaction, ship fuel use, and dedicated injection energy.

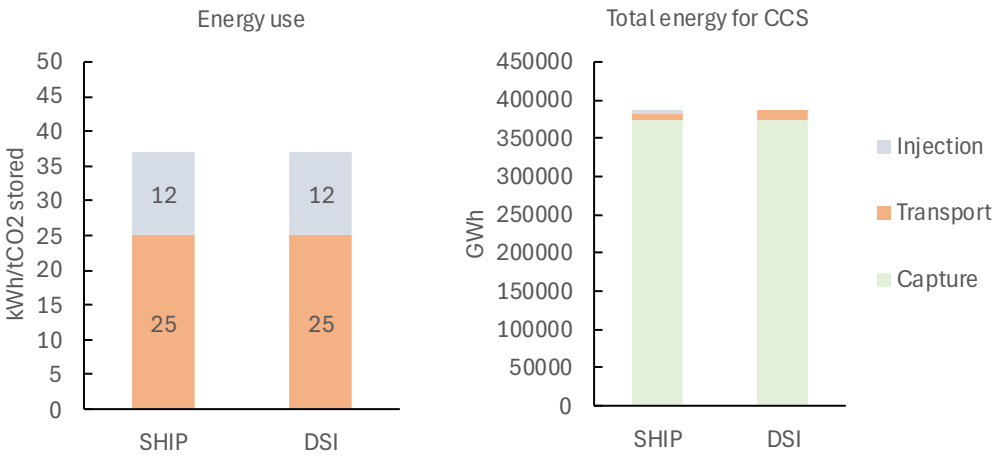


Figure 10. Baltic Sea. Left: transport and injection energy use per tonne of CO_2 stored. Right: total energy demand across the full scenario duration.

No pipeline configuration is evaluated here: only SHIP and DSI are assessed, reflecting the maritime nature of the Baltic Sea logistics chain and the absence of a viable offshore pipeline corridor to the storage site.

3.2.5 Transport and storage additional CO_2 emissions

Over the 2031–2065 period, 351.8 $MtCO_2$ is captured and stored, of which 79.2–79.6 $MtCO_2$ are additional emissions from the capture process and from transport and storage components (Table 15). The differences between the two configurations are minimal over the time frame of the project, and result from the reconditioning at the platform in SHIP imposing slightly higher emissions than direct ship injection. Both options preserve more than 97% of the capture-stage abatement, confirming that the choice of downstream logistics does not have a meaningful impact on the overall performance of the CCS chain.

Table 15. Baltic Sea. Net CCS abatement by scenario, including transport and injection emissions.

	Transport & injection emissions	Net CO_2 Abated	*Unit*
SHIP	7.4	272.1	*$MtCO_2$*
DSI	7.0	272.5	*$MtCO_2$*

3.2.6 Long-term costs evaluation

Capture is common to the two configurations and represents approximately 75–76% of discounted full-chain cost. SHIP therefore remains the lower-cost option, at 26,061 €M or 95.8 €/tCO_2 abated, compared with 26,436 €M or 97.0 €/tCO_2 for DSI, but the full-chain difference is limited. The choice between the configurations is determined by the transport and storage components rather than by capture. The net effect is a modest cost advantage for SHIP, driven mainly by lower transport OPEX (Figure 11).

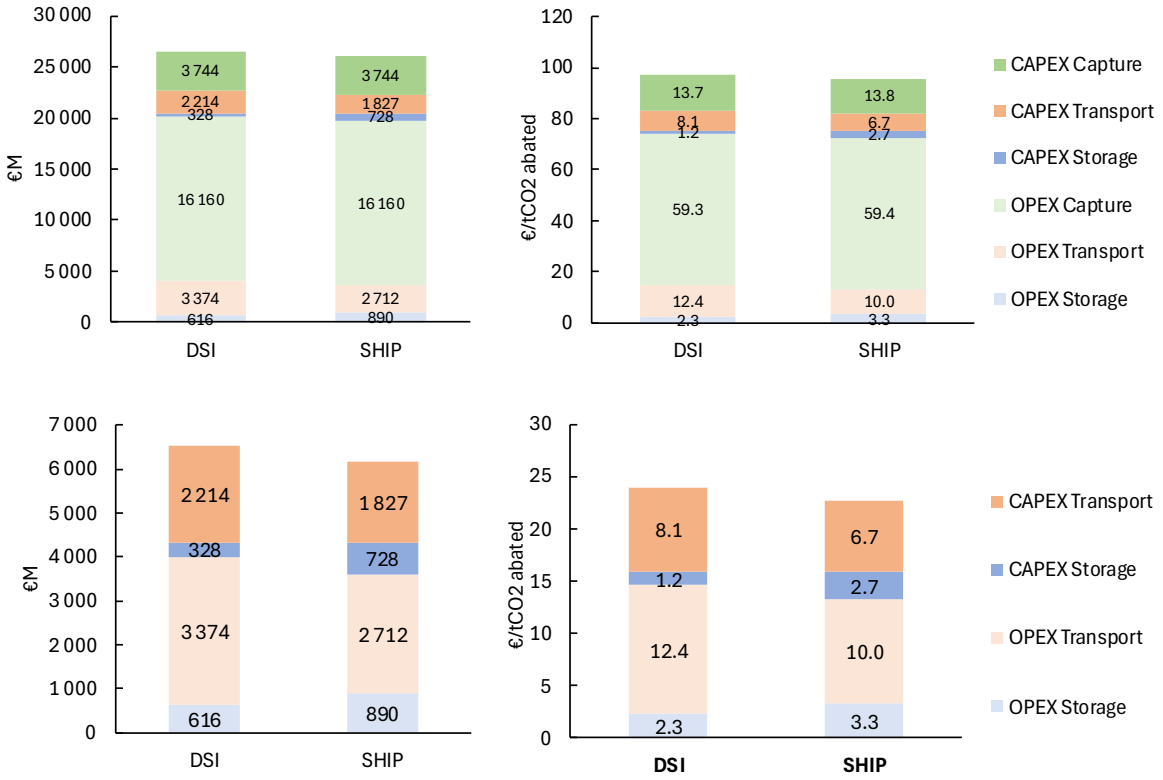


Figure 11. Baltic Sea. Long-term scenarios cost assessment: absolute and specific costs per tonne of CO_2 abated (discounted, in real 2030 €).

Transport and storage comparison

Transport and storage costs are 6,157 €M for SHIP and 6,532 €M for DSI, corresponding to 22.6 €/tCO_2 abated and 24.0 €/tCO_2abated. DSI is therefore approximately 6% more expensive, although both configurations remain within the same cost range. The difference reflects their cost structure. DSI avoids the permanent offshore platform and reduces storage CAPEX, but this saving is offset by higher expenditure on vessel equipment, fuel and offshore injection operations. Figure 12 shows this CAPEX-to-OPEX shift per tonne abated and per tonne stored.

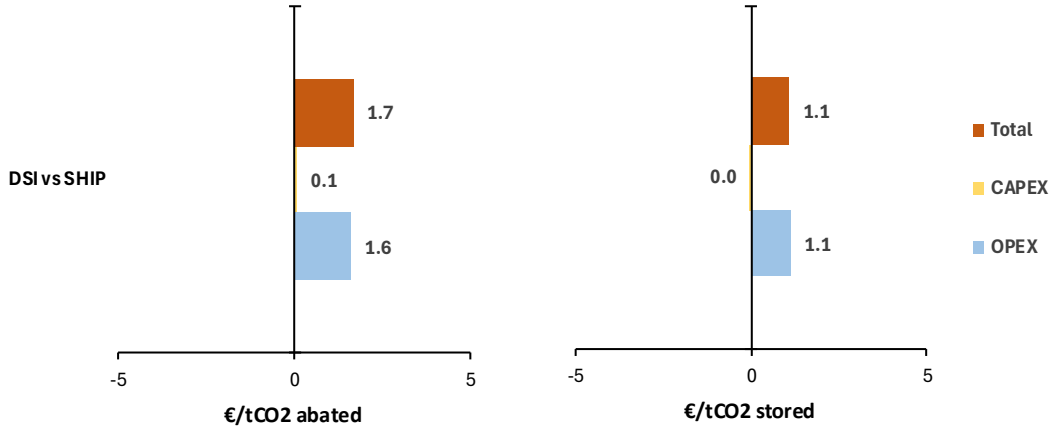


Figure 12. Baltic Sea. Transport and storage cost increment from SHIP to DSI per tonne CO_2 abated (left) and per tonne CO_2 stored (right).

3.2.7 Baltic Sea – conclusions

The techno-economic assessment of a CCS chain serving 16 industrial emitters in the Baltic Sea region, deployed in three phases between 2031 and 2065, supports the following conclusions.

The scenario captures and permanently stores 351.8 $MtCO_2$, reducing baseline industrial emissions from 294.3 $MtCO_2$ to 14.7 $MtCO_2$ of residual emissions. From the stored mass, 18.8 $MtCO_2$ is biogenic CO_2 (delivering net carbon removal at facilities with biogenic feedstocks) and 72.2 $MtCO_2$ corresponds to additional process emissions generated by the capture step itself and routed to storage.

A small number of anchor emitters underpin the economic viability of the shared transport and storage network, since capture is highly concentrated: four facilities (Orlen Lietuva, AB Achema, Auvere SOP, Auvere PP) account for roughly half of the annual captured volume (about 5.95 $MtCO_2$/yr of the 11.13 $MtCO_2$/yr total once fully ramped up). Capture CAPEX (3,744 €M) and capture OPEX (16,160 €M) together represent around 76% of the discounted full-chain cost under SHIP and 75% under DSI, making anchor emitters and capture performance the principal economic drivers.

SHIP is the lower-cost transport and storage configuration: its transport and storage costs total around 6,157 €M versus 6,532 €M for DSI, a premium of about 6% for the direct ship injection configuration (or ~1.7 €/tCO_2 abated). DSI's transport-and-storage premium is OPEX-driven, but DSI reduces undiscounted storage CAPEX by about 47%, from 851.2 €M to 451.2 €M, by removing the offshore receiving platform. On a per-tonne-abated basis, OPEX accounts for +1.6 €/tCO_2 of the +1.7 €/tCO_2 total gap, while CAPEX is essentially neutral (+0.1 €/tCO_2). The relatively small overall difference should be interpreted in the context of the energy-cost assumptions, particularly those associated with offshore CO_2 reconditioning and injection. Changes in electricity prices, marine-fuel costs, or the efficiency of the reconditioning and injection systems could materially affect the retrieved cost difference.

The entire CO_2 stream is allocated to a single storage unit (SU#01), with 8 active injection wells delivering a per-well injection rate of about 160 tCO_2/h under continuous operation, scaling proportionally under batch (ship-based) duty cycles. Storage is, therefore, a genuine differentiator here: SHIP requires a permanent offshore receiving platform and associated subsea distribution equipment, whereas DSI removes that need by having vessels inject directly into the formation. Storage CAPEX differs significantly between the two options (851.2 €M for SHIP versus 451.2 €M for DSI in undiscounted 2030 terms), driven entirely by offshore infrastructure, while well costs and seismic campaigns) are identical. Storage OPEX is the same in both configurations at 22 €M/yr.

Across the full chain, capture dominates energy consumption (~380,000 GWh over the project lifetime). The non-capture energy demand is effectively identical between the two configurations at about 37 kWh/tCO_2 stored.

Both configurations rely on the same ship-based logistics, so their energy profiles and associated emissions broadly align. CO_2 emissions from transport and injection stages amount to 7.4 $MtCO_2$ under SHIP and 7.0 $MtCO_2$ under DSI, yielding net abatements of 272.1 and 272.5 $MtCO_2$ respectively, a 97% effective net abatement over the 2031–2065 horizon, with DSI retaining a small but consistent edge by avoiding the additional handling step at an offshore receiving platform.

Although SHIP presents the lower cost in the baseline case, the two configurations, SHIP and DSI, are regarded as broadly competitive, under the assumptions adopted, for the Baltic Sea scenario. Given the small cost difference and its sensitivity to energy-related OPEX assumptions, the preferred

configuration is likely to depend not only on cost, but also on infrastructure requirements, energy prices, flexibility, permitting and project-specific risk allocation.

Therefore, DSI should not be ruled out and is a valid option for the Baltic Sea: although marginally more expensive, it removes the need for a permanent offshore receiving platform, which may be attractive from a phasing, permitting, or risk-allocation perspective. DSI also delivers a slightly higher net abatement (by ~0.4 $MtCO_2$) thanks to lower chain emissions. The choice between the two is essentially a trade-off between upfront investment in dedicated offshore storage infrastructure (SHIP) and recurring operating expenditure on marine transport and offshore injection (DSI), at broadly similar total cost.

That said, the overall feasibility and bankability of the project will rest far more on the capture stage than on the transport choice. Capture accounts for roughly three quarters of discounted full-chain cost and the vast majority of energy use, and is concentrated in a handful of anchor emitters whose participation is critical to the economics of the shared infrastructure. Transport and storage costs, while material for infrastructure operators (6,100–6,500 €M discounted), shift the overall economics only marginally.

4 Black Sea – Romania

The Romanian scenario combines capture in industrial clusters mostly aligned along navigable rivers, which create opportunities for multimodal transport, with offshore storage in the Black Sea. The transport network allows different offshore transport options to be tested in the TEA, to understand the cost-effectiveness of DSI versus conventional ship and versus offshore pipeline. The scenarios have not suffered any major change since defined in D2.1[8] and the interested reader is referred to that report for further details.

4.1 Scenario overview

Romania is committed to decarbonize according to the targets established by the European Union. The targets are specified in the Integrated National Energy and Climate Plan of Romania 2025–2030[16] (NECP, update October 2024). According to this document, the net GHG (including LULUCF) emission reduction target for Romania is set at 85% by 2030, compared to 1990 levels. Romania has made significant progress, achieving in 2022 85% of its 2030 target for net GHG emission reduction, with a projection of reaching 93% reduction by 2025. The long-term goal is to achieve a 96% net GHG emission reduction by 2040 and complete net GHG emission reduction by 2050: 105% lowering net GHG emissions in 2050 compared to 1990 level. CCUS is explicitly but briefly mentioned in the NECP. It is not mentioned as a key technology.

The Romanian scenario (Figure 13) involves CO_2 capture from industrial installations from Călărași and Constanța (including Medgidia) and offshore storage in potential deep saline aquifers and depleted hydrocarbon fields in the Black Sea, within the Romanian exclusive economic zone. The scenario involves different transport modes, including rail, river transport, short onshore pipelines and three different offshore transport modes that are compared through TEA: offshore pipeline (hereafter PIPE scenario), conventional ships (SHIP) and ships with direct injection capability (DSI).

4.1.1 CO_2 Capture

For the capture part, all the emitters considered and presented in D2.1[8] have been selected for the techno-economic analysis. The scenario consists of 2 capture clusters, Călărași and Constanța.

Călărași cluster consists of 2 installations totalling 0.15 $MtCO_2$ in 2023:

I. S.C. Silcotub S.A., a steel producer**;**
II. S.C. Saint- Gobain Glass România S.R.L., a glass factory.

Constanța cluster, 5 industrial installations have been selected:

i. ROMCIM S.A., a cement plant in Medgidia;
ii. S.C. Termocentrale Constanta S.R.L., a thermo-energetic plant in Constanța;
iii. Rompetrol Energy S.A. – formerly Midia thermo-energy plant;
iv. S.C. Rompetrol Rafinare S.A. – Petromidia – a refinery, and;
v. S.C. Celco S.A , a lime production facility.

In total, the 5 industrial installations emitted 2.03 $MtCO_2$ in 2023. In both clusters, for purposes of the TEA, it is assumed that the selected facilities will continue to emit the same amount of CO_2 as emitted in 2023.

[16]Guvernul României. (2024). Planul Național Integrat în domeniul Energiei și Schimbărilor Climatice 2025–2030: Actualizare 2024 [Integrated National Energy and Climate Plan of Romania 2025–2030: Update].

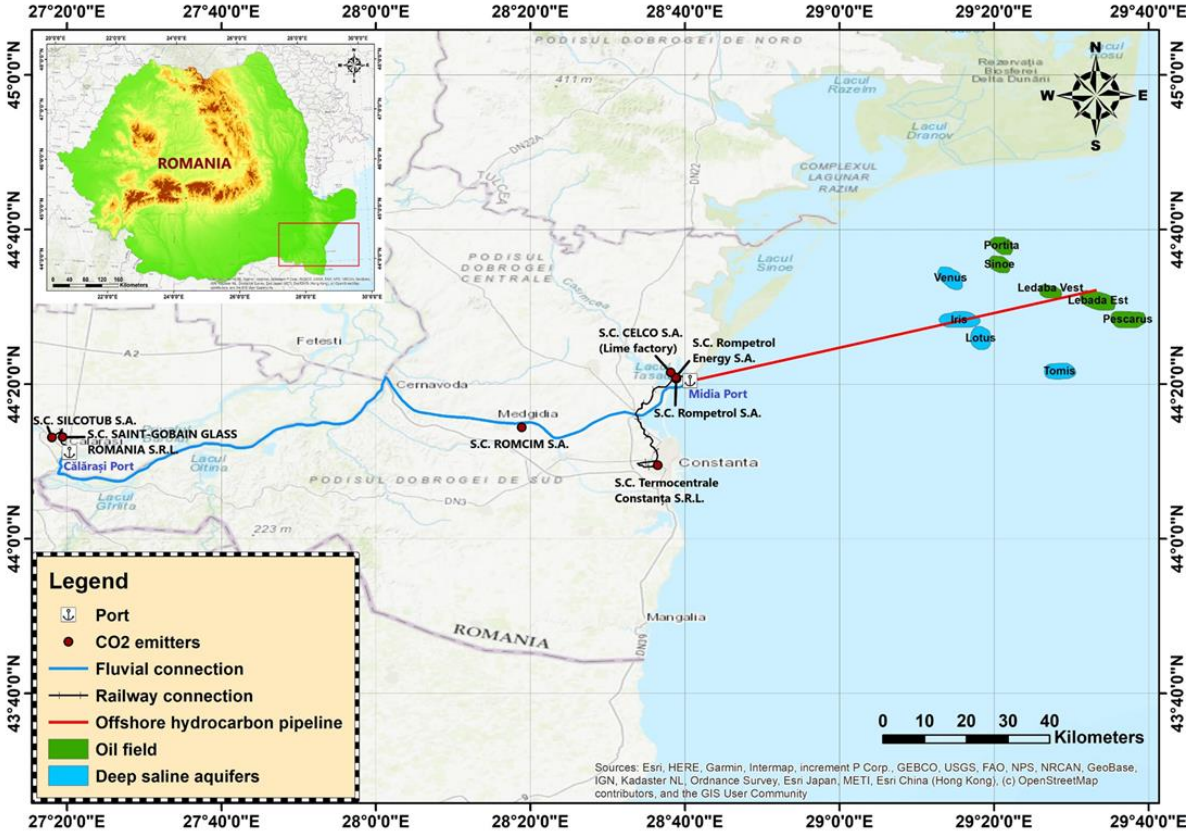


Figure 13. Romanian scenario, showing sources, transport modes and possible offshore reservoirs. The depicted offshore pipeline refers to an existing hydrocarbon pipeline and not to the scenario using a CO_2 offshore pipeline to the Lotus saline aquifer.

4.1.2 CO_2 Storage site

The offshore storage solutions available for the Romanian scenario are four deep saline aquifers (designated Iris, Venus, Tomis, Lotus) and three nearly depleted hydrocarbon fields (Lebada Est, Lebada Vest, Sinoe). These were described in detail in D2.1. The deep saline aquifers have a total estimated capacity 108 $MtCO_2$, while the selected hydrocarbon fields could potentially store 59 $MtCO_2$. Due to the limited amount of data available, these capacity estimations follow the methodology used in the EUGeoCapacity project[17] and are detailed in D2.1, so the associated uncertainties are relatively high.

For the TEA, only 3 sites have been selected, **Iris**, **Lotus** and **Tomis**. The reservoir parameters used for TEA are presented in Table 16.

For the Iris structure, an Albian formation has been selected as the best reservoir for CO_2 storage, composed of quarzitic sandstones with calcareous cement[18]. The seal for the Albian reservoir is represented by the Senonian marly formations. The storage reservoir for Lotus site is represented also by the Albian formation, consisting in calcareous sandstones with thin intercalations of silty clays,

[17] Vangkilde-Pedersen, T., Anthonsen, K., Smith, N., Kirk, K., Frykman, P., Van der Meer, B., Le Gallo, Y., Bossie-Codreanu, D., Wojcicki, A., Le Nindre, Y., Hendriks, C., Dalhoff, F., & Christensen, N. (2009). Assessing European capacity for geological storage of carbon dioxide: The EU GeoCapacity project. Energy Procedia, 1, 2663–2670.

[18] Ionescu, G, Sisman, M, Cataraiani, R, 2002. Source and Reservoir Rocks and Trapping Mechanisms on the Romanian Black Sea Shelf In: Dinu, C. and Mocanu, V. (Editors). Geology and Tectonics of the Romanian Black Sea Shelf and its Hydrocarbon Potential, B.G.F. Special Volume no. 2, pp. 67-85.

protected by a layer of compact blackish clays. The Tomis site has the largest potential for CO_2 storage also in the Albian Formation. The reservoir is comprised of grey sandstones with calcareous cement. The seal is represented by a thin layer of compact blackish Cenomanian marls.

Table 16. Reservoir parameters for the CO2 storage sites.

	Iris	Lotus	Tomis	Unit
Depth of reservoir top	2600	1523	2700	*m*
Reservoir thickness	50	85		*m*
Reservoir Volume	4.50e+10	7.65e+10		m^3
Initial reservoir pore volume	6.75e+09	1.15e+10		m^3
CO_2 density (average)	905.5	662.42	650	kg/m^3
Permeability	170	170	170	$mD\ (10^{-15}m^2)$
Porosity	15–20	15–20	15–20	%
Temperature	35		105	°C
Storage efficiency factor	20	20	20	%
CO_2 storage capacity	28.73	29	33	Mt

4.1.3 CO_2 Transport

The transport of CO_2 is designed as multimodal involving onshore rail, fluvial ship transport and maritime transport for the final segment linking to the offshore storage site. In this final segment for offshore transport, three alternatives are studied and compared through the TEA, namely (i) offshore pipeline, (ii) conventional ship and (iii) direct ship injection (DSI).

Therefore, in the Romanian scenario, the onshore part is common, up to the main hub in Midia port (H#03) and it involves:

- rail connections (from Călărași emitters to Călărași port - H#01, from Constanța emitters E#03, E#02 to Midia H#03);
- fluvial transport (from Călărași port – H#01 to Midia port H#03 and from Medgidia port – H#02 to Midia port H#03) and;
- short pipeline connections (from E#01 to Medgidia port H#02 and from Constanța emitters E#04 and E#07 to Midia port H#03).

The modes and distances for the onshore transport part of the scenario are presented in Table 17.

Table 17. Onshore transport characteristics.

Start local ID	End Local ID	Transport mode	Real distance (km)
E#05	H#01	rail	9
E#06	H#01	rail	6
H#01	H#03	Fluvial ship	130
E#01	H#02	Onshore pipeline	>2
H#02	H#03	Fluvial ship	55
E#02	H#03	rail	30
E#03	H#03	rail	30
E#07	H#03	Onshore pipeline	5.0
E#04	H#03	Onshore pipeline	5.0

Depending on the option chosen for the offshore transport, the Romanian main scenario was divided into three sub-scenarios, analysed separately.

In the PIPE scenario from Midia central hub, an offshore pipeline goes to Lotus (SU#02). From there, CO_2 is redirected through a pipeline distribution system to the other 2 storage sites. For this scenario, it is assumed that the pressure for the injection comes from the onshore transport segment. The offshore pipelines are oversized to minimize pressure loss.

In the SHIP, scenario the ship arrives also at Lotus (SU#02), where a new platform is designed. From this point, the CO_2 is redirected through pipelines to the two other storage sites. The injection pumps and components are placed on the platform.

In the DSI scenario, no platform is necessary due to the flexibility of the solution. The CO_2 is directly transported by the DSI vessel to Lotus (SU#02) and then distributed through pipelines to other storage sites. Reconditioning and pumping of CO_2 is made onboard.

4.2 Techno-economic assessment results

4.2.1 Capture

The seven emitters in the scenario released 2.2 $MtCO_2$/yr in 2023. Figure 14 shows the annual amount of CO_2 captured at each facility, including the additional CO_2 generated by the capture process and captured along with the flue-gas CO_2. In total, 2.6 $MtCO_2$/yr is captured, higher than the 2.2 $MtCO_2$/yr of baseline industrial emissions because the capture process itself generates additional CO_2 which is also captured and routed to storage. Two emitters — E#07 (oil refinery) and E#01 (cement plant) — account for 2.01 $MtCO_2$/yr, or ~77% of the total captured. The remaining five emitters together account for 0.58 $MtCO_2$/yr.

By cluster, the Călărași cluster captures 0.21 $MtCO_2$/yr, while the Constanța cluster captures 2.39 $MtCO_2$/yr.

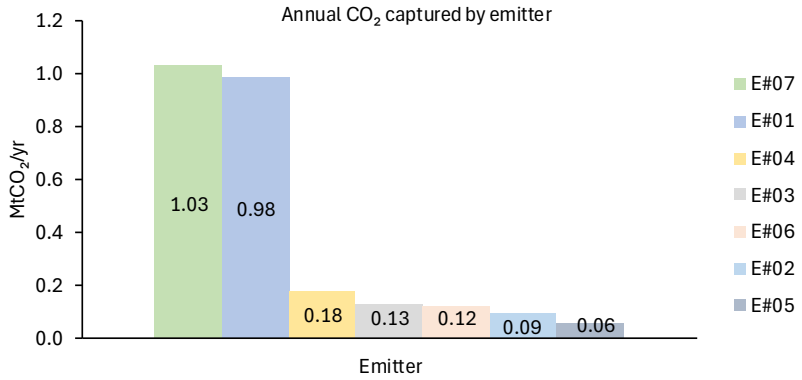


Figure 14. Black Sea – Romania. Annual CO_2 mass captured per emitter.

At the 2023 emissions rate, and over the scenario timeframe, the seven facilities would emit 67.7 $MtCO_2$ to the atmosphere in the absence of CCS (Table 18). With CCS implemented, the model accounts for the additional CO_2 generated by the capture process itself, for example from energy supply, which is also captured. Total CO_2 captured and stored over the scenario period is therefore 80.4 $MtCO_2$, comprising 64.3 $MtCO_2$ captured from industrial flue gases and 16.1 $MtCO_2$ of capture-process CO_2. No biogenic CO_2 is captured in this scenario. After CCS implementation, residual uncaptured atmospheric emissions from the industrial facilities are reduced to 3.4 $MtCO_2$ over the scenario period, corresponding to an emission reduction of 64.3 $MtCO_2$ relative to the no-CCS baseline.

Table 18. Black Sea – Romania. CO_2 mass balance from the CCS chain at the capture stage.

CO_2 mass balance (2035–2065)		
Baseline industrial emissions (no CCS)	67.7	$MtCO_2$
CO_2 captured	80.4	$MtCO_2$
Biogenic CO_2 captured	0	$MtCO_2$
Process emissions from capture	16.1	$MtCO_2$
CO_2 stored	80.4	$MtCO_2$
Net industrial emissions with CCS	3.4	$MtCO_2$
Emission reduction (vs baseline) at the capture stage	64.3	$MtCO_2$

4.2.2 Transport

The Black Sea–Romania scenarios involve a complex transport network comprising pipelines, rail, barge, and ship, which results in a multi-step CO_2 conditioning and reconditioning chain along the transport route.

Across all three scenarios, the onshore network and transport modes are identical. The key difference lies in the link between the onshore collection hub (Midia Port) and the offshore distribution hub (SU#02, Lotus). In the PIPE scenario, this link is provided by a pipeline. In the SHIP scenario, CO_2 is transported by a conventional CO_2 carrier and offloaded via an offshore platform. In the DSI scenario, CO_2 is transported by a ship that injects it directly offshore.

To avoid repetition, results for every connection are not shown in each scenario. The PIPE scenario presents all connections and transport modes, whereas the SHIP and DSI scenarios focus solely on the offshore link results (conventional ship and direct-injection ship, respectively).

4.2.2.1 *Scenario I – Pipeline (PIPE)*

Pipeline CO_2 transport

The PIPE scenario includes six pipeline connections, comprising three onshore and three offshore pipelines, with a combined length of approximately 83 km. The onshore pipelines are short-distance feeder lines, totalling around 10 km. The offshore pipelines total approximately 73 km, including a 51 km main pipeline between Midia Port and SU#02, and two shorter connections from SU#02 — Lotus — to SU#01 — Iris — and SU#03 — Tomis.

Table 19 presents the main characteristics of the pipelines in the scenarios. For the small onshore feeder pipelines, a transport pressure of 90 bar is considered, requiring up to 10 bar of additional pumping (in relation to the assumed 80 bar delivered from capture). For the main offshore pipeline, pumping is applied onshore, with no intermediate booster station. The inlet pressure for transport is 120 bar. Across the pipeline network, inlet pressures range from 90 to 120 bar, while outlet pressures range from 86 to 110 bar. Booster compression requirements, at the start of each pipeline, range from 0 to 40 bar, depending on the pipeline segment.

Per pipeline, total CO_2 transported over the scenario period ranges from 5.4 to 80.4 $MtCO_2$, while annual transported volumes range from 0.2 to 2.6 $MtCO_2$/yr. Individual pipeline lengths range from 1.3 to 51 km. Pipe dimensions also vary, with outside diameters of 121–356 mm and wall thicknesses of 3.4–9.5 mm.

Table 19. Black Sea – Romania. PIPE scenario pipelines characteristics.

	Range	Unit
Total CO_2 transported per pipeline (scenario)	5.4–80.4	*Mt*
Annual CO_2 transported per pipeline	0.2–2.6	*$MtCO_2$/yr*
Pipeline length (individual pipelines)	1.3–51	*km*
Outside diameter	121–356	*mm*
Inside diameter	115–337	*mm*
Wall thickness	3.4–9.5	*mm*
Booster compression	0–40	*bar*
Inlet pressure	90–120	*bar*
Outlet pressure	86–110	*bar*

Pipeline transport requires 67.0 €M of CAPEX and 2.0 €M/yr of OPEX. Almost all initial expenditure lies in the pipelines, while pumping remains limited because the CO_2 is delivered pre-pressurised. The component breakdown is provided in Table 20.

Table 20. Black Sea – Romania. CAPEX and OPEX of pipelines. (Values are undiscounted and represent costs in 2030 terms).

	Pipelines	Pumping	
CAPEX	65.0	2.0	€M
OPEX	1.5	0.5	€M/yr

Barge CO_2 transport

Fluvial transport is considered because several CO_2 sources are located close to navigable waterways. Two barge connections are included in the scenario (Table 21). The first connection, B#01, transports CO_2 from Călărași to Midia over a sailing distance of 130 km, using the Danube River, the Danube–Black Sea Canal, and the Poarta Albă–Midia Năvodari Canal. The second connection, B#02, transports CO_2 from Medgidia to Midia over a sailing distance of 55 km, using the Danube–Black Sea Canal and the Poarta Albă–Midia Năvodari Canal.

Over the scenario period, B#01 transports a total of 5.4 $MtCO_2$, with a maximum annual transport rate of 0.2 $MtCO_2$/yr. This connection requires one 2,000 tCO_2 barge and approximately 92 trips per year. B#02 transports a larger total volume of 30.5 $MtCO_2$, with a maximum annual transport rate of 1.0 $MtCO_2$/yr. As a result, this connection requires two 2,000 tCO_2 barges and approximately 259 trips per year.

For both connections, the assumed loading and unloading rates are 1,500 tCO_2/h, and the sailing speed is 6 knots. Buffer storage is also included at the terminals, with 2,280 tCO_2 for B01 and 4,560 tCO_2 for B02. At Midia, CO_2 conditioning is required before transfer to the offshore pipeline system, where CO_2 is transported in dense phase.

Table 21. Black Sea – Romania. Barges CO_2 transport characteristics.

BARGES	B01	B02	Unit
Total CO_2 transported	5.4	30.5	*Mt*
Max. CO_2 transported	0.2	1.0	*$MtCO_2$/yr*
Sailing distance	130	55	*km*
Number of barges	1	2	
Barge size	2,000	2,000	*tCO_2*
Loading rate	1,500	1,500	*tCO_2/h*
Unloading rate	1,500	1,500	*tCO_2/h*
Sailing speed	6	6	*knot*
Buffer storage	2,280	4,560	*tCO_2*
Number of trips	92	259	*per year*

The two barge connections are driven mainly by barge acquisition and liquefaction costs. Their role is to connect inland sources located near navigable waterways to Midia, but this flexibility introduces additional conditioning and terminal handling compared with direct pipeline collection (Figure 15).

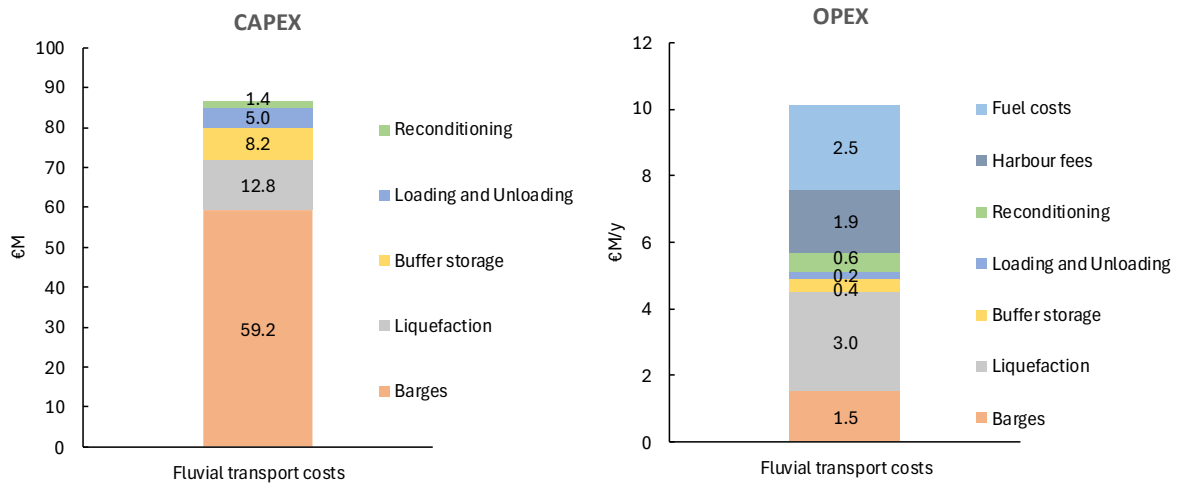


Figure 15. Black Sea – Romania. CAPEX and OPEX of barges. (Values are undiscounted and represent costs in 2030 terms).

Train CO_2 transport

Four rail connections were assessed to transport a total of 0.4 $MtCO_2$/yr. These are short routes, 6–30 km in length. Given the short distances and relatively small volumes, the model assumes a higher number of trips using smaller trainsets, with 2–4 cryogenic tank wagons, each carrying 50 tCO_2. In practice, it may be preferable to reduce the number of trips by increasing the number of wagons per train. However, this would require larger buffer storage capacity and would increase the frequency of downstream loading/unloading operations.

Liquefaction and rail assets dominate the investment, while liquefaction is the main operating cost. The high trip frequency should be considered indicative, as longer trainsets could reduce the number of trips at the expense of larger buffer storage and handling capacity (Figure 16).

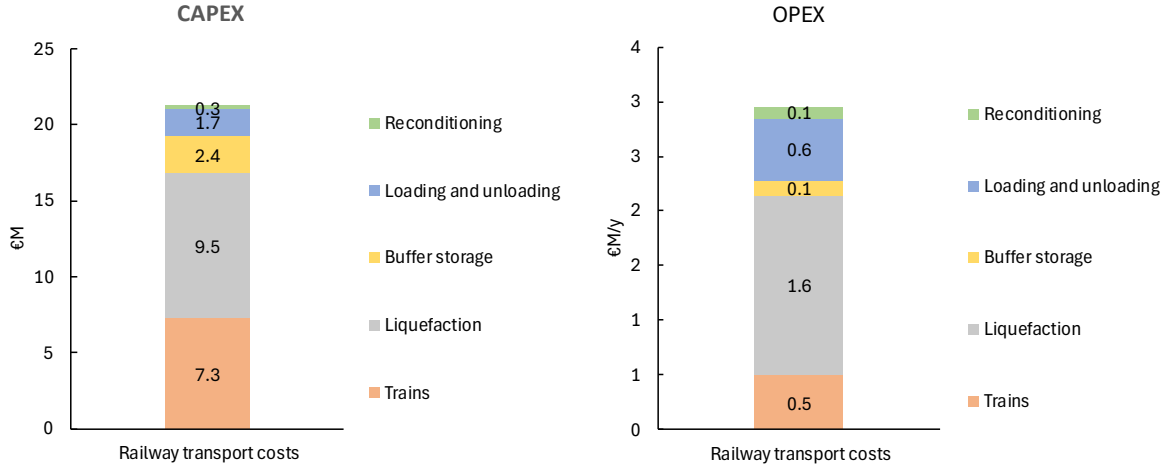


Figure 16. Black Sea – Romania. CAPEX and OPEX of transport by train. (Values are undiscounted and represent costs in 2030 terms).

4.2.2.2 Scenario II – Conventional CO_2 ship (SHIP)

Route S#01 describes a short-distance conventional CO_2 shipping link (Table 22). One 25,000 tCO_2 vessel operates over a 51 km sailing distance at 10 knots, completing ~110 roundtrips per year. The route is sized for up to 2.6 $MtCO_2$/yr of CO_2 transport, corresponding to 80.4 $MtCO_2$ transported over

the 31 years scenario period. Terminal transfer capacities are 3,000 tCO_2/h for loading and 600 tCO_2/h for offshore unloading and injection, making unloading the slower (potentially limiting) operation. A 28,500 tCO_2 buffer storage capacity is considered to buffer variations in flow and coordinate continuous CO_2 supply with the vessel's batch shipping schedule.

Table 22. Black Sea – Romania. Conventional ship CO2 transport characteristics.

Ship	S#01	*Unit*
Total CO_2 transported	80.4	*Mt*
Max. CO_2 transported	2.6	*$MtCO_2/yr$*
Sailing distance	51	*km*
Number of ships	1	
Ship size	25,000	*tCO_2*
Loading rate	3,000	*tCO_2/h*
Unloading rate	600	*tCO_2/h*
Sailing speed	10	*knot*
Number of roundtrips	110	*per year*
Buffer storage	28,500	*tCO_2*

The SHIP link between Midia and Lotus requires approximately 204 €M of CAPEX and 11.4 €M/yr of OPEX. Vessels dominate the investment, while liquefaction and ship operation are the main recurring costs. Since part of the CO_2 arrives at Midia already liquefied by rail or barge, terminal liquefaction applies only to the remaining flow (Figure 17).

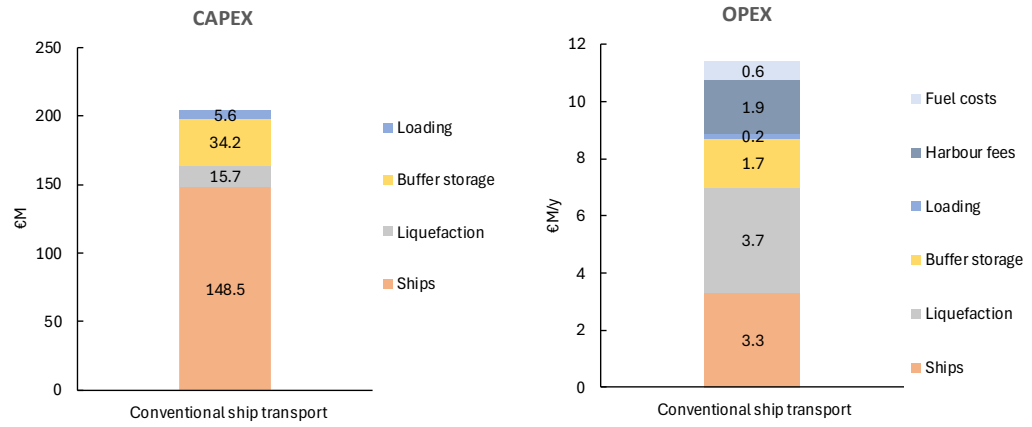


Figure 17. Black Sea – Romania. CAPEX and OPEX of SHIP scenario. (Values are undiscounted and represent costs in 2030 terms).

4.2.2.3 Scenario III – Direct ship injection (DSI)

DSI adds onboard reconditioning and injection equipment to the same maritime transport concept, increasing CAPEX to approximately 284 €M and OPEX to 14.5 €M/yr. The difference from SHIP is

therefore associated mainly with unloading-equipment investment and fuel use, rather than with changes to the upstream collection network (Figure 18).

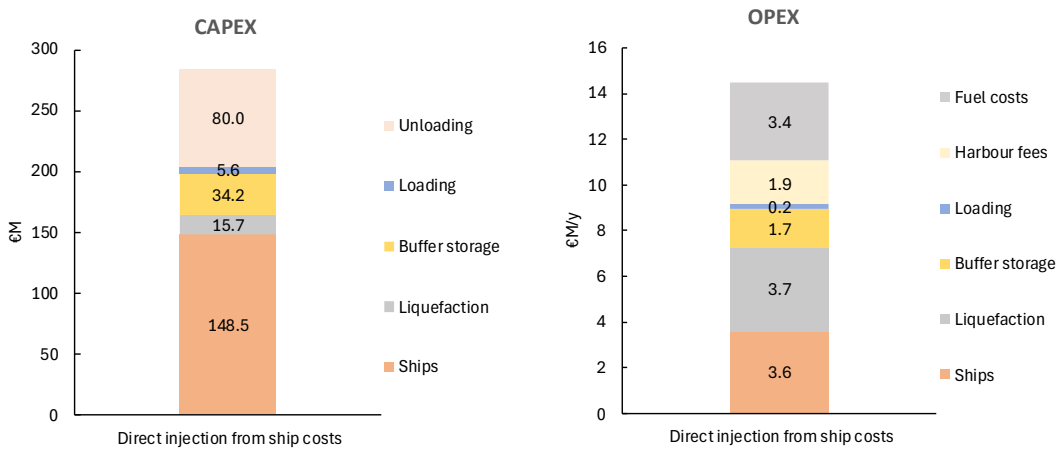


Figure 18. Black Sea – Romania scenario. CAPEX and OPEX of DSI scenario. (Values are undiscounted and represent costs in 2030 terms).

4.2.3 Storage

The storage developments are sized around three injection units (SU01 Iris, SU02 Lotus and SU03 Tomis, Table 23), each using one well and delivering a continuous injection rate of ~98–104 t/h, which corresponds to annual injection rates of 0.83–0.91 $MtCO_2$/yr and totals of 25.7–28.1 $MtCO_2$ stored over the project period.

Table 23. Black Sea – Romania. Storage parameters.

	Iris (SU#01)	Lotus (SU#02)	Tomis (SU#03)	Unit
Annual injection rate	0.86	0.83	0.91	*$MtCO_2$/yr*
Total CO_2 stored	26.5	25.7	28.1	*$MtCO_2$*
Number of injection wells (active)	1	1	1	
Average injection rate per well (if continuous)	98	95	104	*t/h*

In the cost breakdown (Figure 19), CAPEX is dominated by infrastructure, while wells (116.4 €M) and seismic campaigns (60 €M) are common to all cases. Infrastructure varies by scenario — 272 €M for PIPE, 521 €M for SHIP and 250 €M for DSI — driving total storage CAPEX to 448 €M, 697 €M and 426 €M, respectively. The principal CAPEX driver in SHIP is the offshore platform required for injection.

Annual OPEX excluding energy costs is identical across the three scenarios at 34.5 €M/yr, consisting of 30 €M/yr for infrastructure and 4.5 €M/yr for wells. Scenario-specific injection energy is accounted for separately in the long-term assessment; the undiscounted storage-cost differences in the following Figure 19 therefore arise mainly from upfront infrastructure.

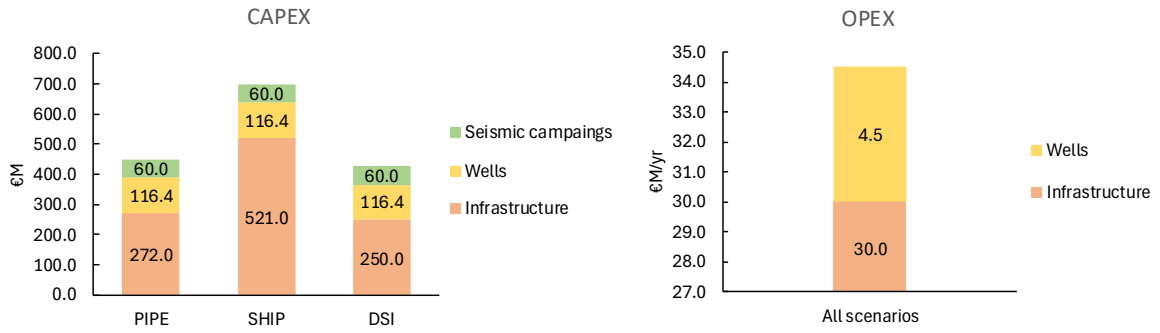


Figure 19. Black Sea – Romania. Storage costs excluding energy use. OPEX is identical across the three scenarios and is therefore shown as a single bar. (Values are undiscounted and represent costs in 2030 terms).

4.2.4 Energy consumption

Total energy demand is dominated by the CO_2 capture process (Figure 20). In comparison, the additional energy required for transport and injection is much smaller, but it differs across the three configurations.

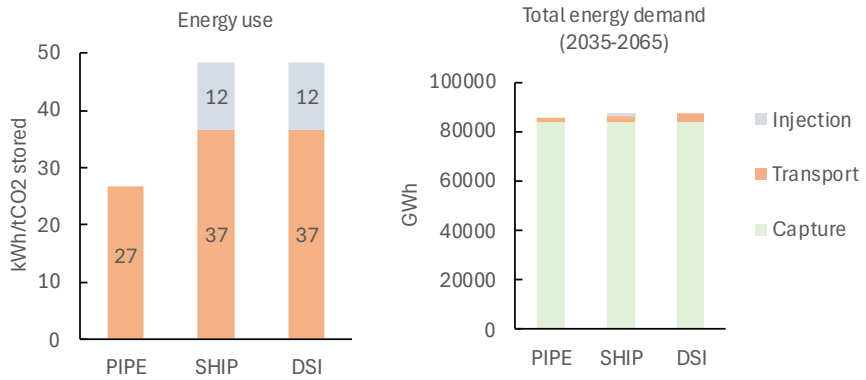


Figure 20. Black Sea – Romania. Left: transport and injection energy use per tonne of CO_2 stored. Right: total energy demand across the full scenario duration.

For PIPE, the transport energy requirement is about 27 kWh/tCO_2 stored. Although the pipeline itself requires very little energy, the upstream collection chain involves liquefaction and reconditioning steps to enable rail and barge transport from the inland emitters to the Midia Port hub, where the CO_2 is then reconditioned to dense phase for offshore pipeline transport. These conditioning steps and barges fuel account for the bulk of PIPE's transport energy demand.

SHIP and DSI require somewhat higher transport energy, at around 37 kWh/tCO_2 stored each. They share the same upstream rail and barge liquefaction and reconditioning steps as PIPE, but add a further liquefaction stage at Midia Port to prepare the CO_2 for ship transport, instead of the dense-phase reconditioning used in PIPE. This additional liquefaction duty, together with diesel consumption during the maritime voyage, raises ship-based transport energy by roughly 10 kWh/tCO_2 relative to PIPE.

Injection energy is required for the ship-based cases only. Figure 20 shows injection energy of roughly 12 kWh/tCO_2 stored for both SHIP and DSI, while PIPE assumes no additional injection energy, because the pipeline delivery conditions provide sufficient pressure for injection at the storage site. Overall, the ship-based configurations have higher non-capture energy demand than PIPE — about 49 vs 27 kWh/tCO_2 stored — due to the combined effect of additional CO_2 liquefaction at Midia, ship fuel use, and dedicated injection energy.

4.2.5 Transport and storage additional CO_2 emissions

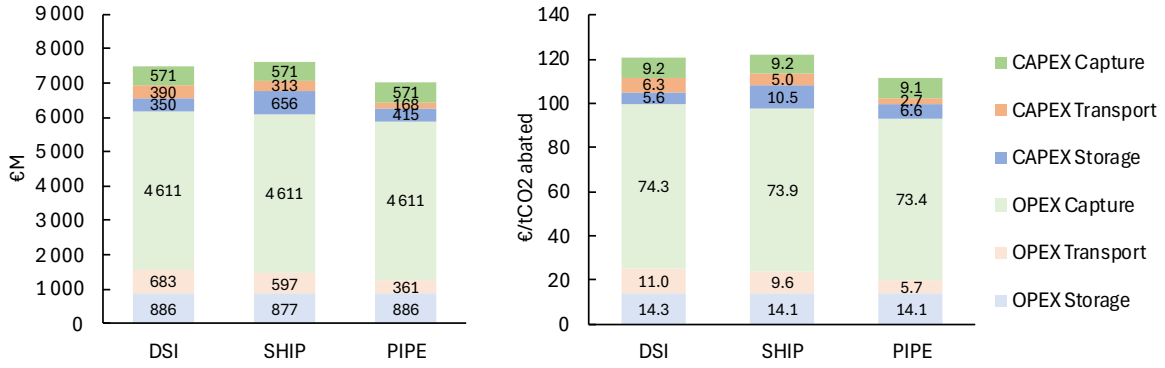
Over the 2035–2065 period, 80.4 $MtCO_2$ are captured and stored, of which 16.1 $MtCO_2$ are additional emissions from the capture process, yielding a net reduction of 64.3 $MtCO_2$ versus the 67.7 $MtCO_2$ expected emissions if CCS is not deployed. Table 24 extends the analysis downstream by accounting for the additional CO_2 emitted from transport and injection processes. The PIPE scenario adds the lowest burden, with only 1.5 $MtCO_2$ of extra emissions and a final abatement of 62.8 $MtCO_2$, followed by SHIP (1.9 $MtCO_2$ emitted, 62.4 $MtCO_2$ abated) and DSI (2.2 $MtCO_2$ emitted, 62.1 $MtCO_2$ abated). The differences between scenarios are small in absolute terms but consistent: shipping and direct ship injection introduce slightly higher chain emissions than pipeline transport, marginally eroding the net climate benefit. Even so, all three options preserve more than 96% of the capture-stage abatement once transport and injection are included, confirming that the choice of downstream logistics has only a limited impact on the overall performance of the CCS chain, with pipelines retaining a small but consistent edge.

Table 24. Black Sea – Romania. Net CCS abatement by scenario, including transport and injection emissions.

	Transport & injection emissions	Net CO_2 Abated	*Unit*
PIPE	1.5	62.8	*$MtCO_2$*
SHIP	1.9	62.4	*$MtCO_2$*
DSI	2.2	62.1	*$MtCO_2$*

4.2.6 Long-term costs evaluation

Capture is common to the three configurations and represents approximately 68–74% of discounted full-chain cost. PIPE has the lowest total cost, at 7,012 €M or 111.6 €/tCO_2 abated, followed by DSI at 7,491 €M or 120.7 €/tCO_2 and SHIP at 7,625 €M or 122.3 €/tCO_2. The full-chain spread is about 9%; when capture costs are excluded, the cost gap between the configurations are clearer (Figure 21).



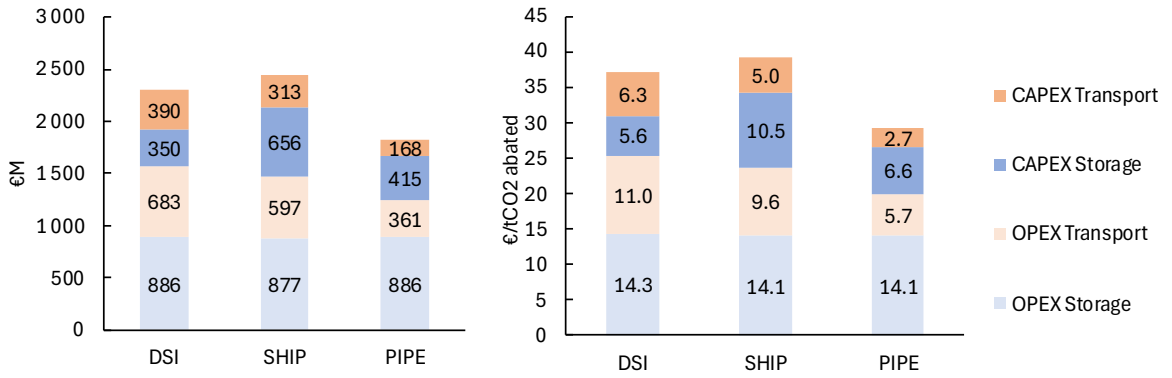


Figure 21. Black Sea – Romania. Long-term scenarios cost assessment: absolute and specific costs per tonne of CO2 abated (discounted, in real 2030 €).

Transport and storage comparison

Excluding capture, PIPE costs 1,830 €M or 29.1 €/tCO_2 abated, compared with 2,309 €M or 37.2 €/tCO_2 for DSI and 2,443 €M or 39.2 €/tCO_2 for SHIP. The ship-based configurations are therefore approximately 28–35% more expensive per tonne. PIPE benefits from low transport expenditure, SHIP is the most CAPEX-intensive because of the offshore platform, and DSI is more OPEX-driven.

Table 25 confirms this ranking. Per tonne abated, SHIP and DSI cost approximately 10.1€/tCO_2 and 8.1 €/tCO_2 more than PIPE, respectively. DSI is approximately 2.0 €/tCO_2 cheaper than SHIP because it saves CAPEX more than offsets its higher OPEX. The decision between SHIP and DSI is therefore a CAPEX / OPEX trade-off, while PIPE remains the clear least-cost configuration.

Table 25. Black Sea – Romania. Transport and storage cost increment between scenarios. Positive values indicate that the first scenario listed is more expensive than the second, while negative values indicate that it is cheaper.

Cost difference	Total (€/tCO_2 abated)	CAPEX (€/tCO_2 abated)	OPEX (€/tCO_2 abated)	Main interpretation
SHIP vs PIPE	+10.1	+6.3	+3.8	SHIP is more expensive mainly due to liquefaction, marine transport and offshore storage investment.
DSI vs PIPE	+8.1	+2.6	+5.4	DSI is also more expensive than PIPE, but the increase is more OPEX-driven, especially due to marine operations and maritime diesel.
DSI vs SHIP	−2.0	−3.6	+1.6	DSI is slightly cheaper overall because it saves on CAPEX, mainly offshore storage investment, but incurs higher OPEX.

4.2.7 Black Sea – Romania conclusions

The Romanian case compares PIPE, SHIP and DSI for seven industrial emitters over 2035–2065. Total CO_2 captured and stored is 80.4 $MtCO_2$, of which 64.3 $MtCO_2$ originates from industrial flue gases and 16.1 $MtCO_2$ from process emissions of the capture step itself. The three scenarios have an identical onshore transport network of pipelines, rail and barge transport, and differ only in the offshore link between Midia Port and the storage complex.

All three scenarios deliver broadly similar net abatement (62.1–62.8 $MtCO_2$), more than 96% of the capture-stage abatement. PIPE is marginally cleanest, with chain emissions of 1.5 $MtCO_2$ versus 1.9 $MtCO_2$ for SHIP and 2.2 $MtCO_2$ for DSI. Non-capture energy is around 27 kWh/tCO_2 stored for PIPE and around 49 kWh/tCO_2 for the ship-based options, with the difference driven by additional liquefaction at Midia and dedicated injection energy in SHIP and DSI. From a pure mitigation standpoint, the choice of transport mode is therefore not decisive.

Total full-chain discounted cost is lowest for PIPE (≈7,012 €M; 111.6 €/tCO_2 abated), followed by DSI (≈7,491 €M; 120.7 €/tCO_2) and SHIP (≈7,625 €M; 122.3 €/tCO_2), giving a full-chain spread of about 9%. For transport and storage, PIPE costs approximately 29.1 €/tCO_2 abated, compared with 37.2 €/tCO_2 for DSI and 39.2 €/tCO_2 for SHIP. DSI and SHIP are therefore approximately 28% and 35% more expensive than PIPE, respectively.

Pipeline transport offers the lowest cost, lowest chain emissions and lowest non-capture energy demand, and is the preferred configuration for the Black Sea – Romania scenario whenever it is technically and commercially feasible. Ship-based options would remain credible alternatives where pipelines are not viable — for example if more distant offshore storage sites are selected, in phased deployments, or where flexibility in source aggregation is needed — with cost penalties of around 9% at full-chain level and 28–35% on the transport and storage portion alone. Within the ship-based options, SHIP or DSI should be selected based on the project's preferred balance between upfront investment and recurring operating expenditure.

This ranking remains sensitive to grid carbon intensity, discount rate, fuel, and the share of CO_2 arriving already liquefied by rail or barge, which impacts SHIP and DSI liquefaction duty.

5 Black Sea – Ukraine

The CCS scenario for storage of CO_2 in the Black Sea from Ukrainian sources builds upon the framework developed in D2.1[8], refined taking into account the results of a preliminary TEA and updated forecasts for long-term emissions for the relevant industrial sources.

The main updates concern transportation configurations, available CO_2 volumes for capture and assumptions on offshore storage capacities. The CTS scenarios are aligned with Ukraine's national climate and energy policies, as well as international climate commitments. The Ukrainian Black Sea scenarios investigates the feasibility of capturing CO_2 emissions from identified industrial clusters in the Odesa and Mykolaiv regions and transporting them to offshore geological storage sites.

5.1 Scenario overview

The national targets for reducing GHG emissions in Ukraine are defined in the National Energy and Climate Plan (NECP) until 2030[19], which foresees a reduction of GHG emissions by 65% compared to 1990 levels, as well as the achievement of climate neutrality of the energy sector by 2050 and economy-wide climate neutrality by 2060. In addition, the Energy Strategy of Ukraine until 2050[20] outlines long-term decarbonisation pathways, including the deployment of cleaner energy technologies, enhanced energy efficiency measures and the introduction of CCS.

The Ukrainian scenarios focus on major stationary emitters located in the Odesa and Mykolaiv regions, which together accounted for approximately 3.54 $MtCO_2$ in 2021[21]. These regions were selected due to their proximity to the Black Sea, existing industrial infrastructure and concentration of emissions-intensive activities. The industrial base in Odesa and Mykolaiv includes enterprises from multiple sectors including: cement, oil refining, machinery manufacturing and repair, metallurgy and metalworking, chemical industry, etc. Although multiple sectors are present, the cement sector dominates emissions.

Given the number of sources, and the current geopolitical context, no attempt was made to design onshore transport networks, and the Odesa and Mikolaev regional emissions are considered at gathering hubs in the ports rather than at the individual facilities. From these hubs, CO_2 is transported offshore for geological storage sites in the Black Sea.

The offshore segment of the scenario considers two main prospective storage sites: Holitsyna and Shtormove fields (Figure 22). These sites have been identified based on available geological data and previous hydrocarbon exploration activities, with an estimated combined storage capacity of approximately 205 $MtCO_2$. The average distance between the onshore CO_2 hubs and the offshore storage sites is approximately 130 km.

[19] Cabinet of Ministers of Ukraine. (2023). Розпорядження № 373-р від 21 квітня 2023 р.: Про схвалення Енергетичної стратегії України на період до 2050 року [Order No. 373-r of 21 April 2023: On approval of the Energy Strategy of Ukraine for the period up to 2050].

[20] Cabinet of Ministers of Ukraine. (2023). Розпорядження № 373-р від 21 квітня 2023 р.: Про схвалення Енергетичної стратегії України на період до 2050 року [Order No. 373-r of 21 April 2023: On approval of the Energy Strategy of Ukraine for the period up to 2050].

[21] State Statistics Service of Ukraine. Official website: https://stat.gov.ua/uk.

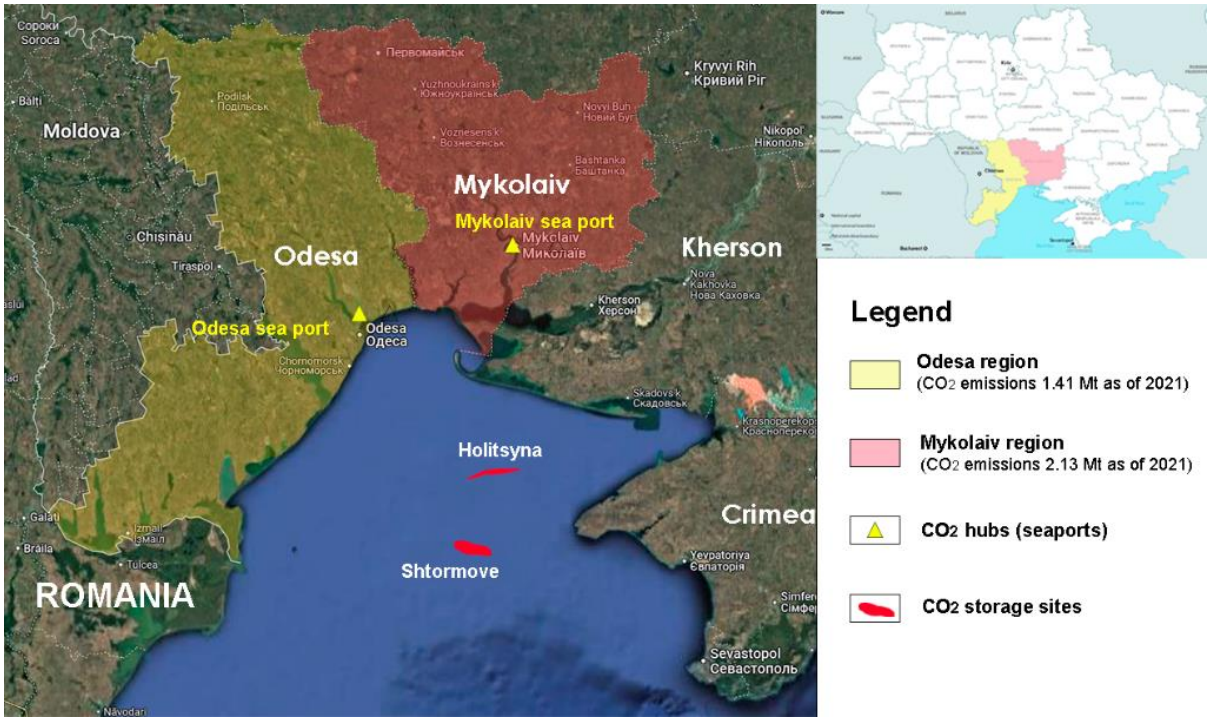


Figure 22. Map with target regions, potential CO2 hubs and storage facilities for the Ukraine scenario.

The TEA evaluates three alternatives: (1) dedicated offshore pipelines connecting onshore hubs to storage sites (PIPE); (2) conventional CO_2 shipping (SHIP); (3) and transport and direct ship injection (DSI).

5.1.1 CO_2 Capture

The Ukrainian CO_2 capture scenario is assessed at a regional level and focuses on two southern regions, Odesa and Mykolaiv, which are characterized by significant industrial activity and well-developed seaport infrastructure. These regions were selected due to their strategic location along the Black Sea coast, enabling efficient integration with offshore CO_2 transport and storage solutions. Within the assessed regions, the cement sector is identified as the primary source of CO_2 emissions, totalling approximately 3.7 $MtCO_2$, with 1.6 $MtCO_2$ from facilities in Odesa and 2.1 $MtCO_2$ from Mykolaiv. This sector is considered as a key target for the early deployment of carbon capture technologies in Ukraine and the associated emissions can provide a sufficiently large and concentrated stream suitable for the development of a regional CCS value chain.

For the purposes of this scenario, full pre-war production capacities are assumed. This approach aligns with Ukraine's long-term reconstruction and industrial recovery plans, which envisage the restoration and modernization of key industrial facilities, including cement plants.

5.1.2 CO_2 Storage site

The targeted offshore storage sites are the Holitsyna and Shtormove fields in the Black Sea, located in the Karkinite–North Crimean Depression. These potential CO_2 storage reservoirs are gas and gas condensate formations primarily of the Oligocene–Lower Miocene (Maykop series) and Lower Paleocene. They consist of clay-rich, carbonate (limestones, marls), and terrigenous (sandstones) sediments, with porosity ranging from 20% to 30% at depths between 950 m and 2,500 m (Table 26).

The Holitsyna field, discovered in 1971, is the first offshore gas condensate field in the Black Sea. It is located approximately 130 km from Odesa in 30–40 m water depth. The geological structure includes sediments from the Lower Paleocene, Eocene, and Oligocene (Maykop series), with the Paleocene section sealed by Eocene clay layers[22]. The П-XI reservoir, considered a potential CO_2 storage site, comprises organogenic-detrital and fractured pelitomorphic limestones of the Lower Paleocene, forming an elongated anticlinal fold covering an area of 43.17 km² (Figure 23).

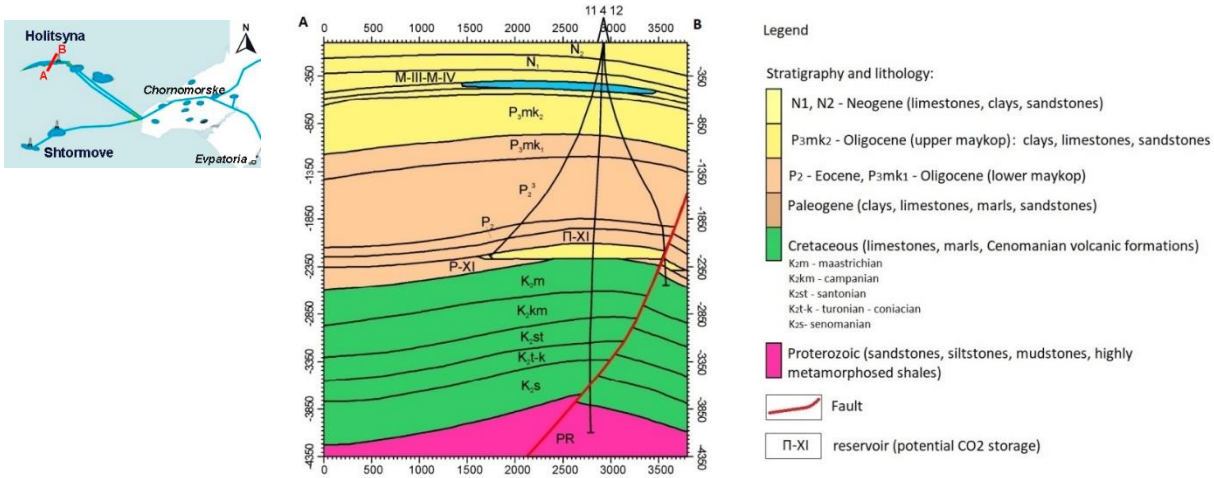


Figure 23. Stratigraphy in area of the Holitsyna field potential storage site in the Ukraine scenario.

The Shtormove field is located 82 km southwest of Chornomorske (Crimea) in the Black Sea. The П-XI reservoir, considered for CO_2 storage, consists of microcrystalline fractured limestones of the Lower Paleocene with a porosity of 30%, at a depth of 986 m, covering a total area of 20.25 km². The reservoir is sealed by Eocene marls and clays (Table 26).

Some parameters were refined compared with the results and methodology presented in D2.1, and the total theoretical, most likely, CO_2 storage capacity of the two studied fields is estimated at approximately 205 Mt. Incomplete subsurface data introduce uncertainty in the storage capacity. Operational scenarios and development plans can proceed once the geopolitical situation is resolved.

Table 26. Reservoir parameters for the CO_2 storage sites in the Black Sea in Ukraine.

Field name	Holitsyna	Shtormove	Unit
Age	Lower Paleocene	Lower Paleocene	
Target reservoir	П-XI reservoir	П-XI reservoir	
Area	43.17	20.25	*km²*
Reservoir depth	2155	986	*m*
Average reservoir thickness	80	85	*m*
Average porosity	15	17	*%*
Permeability	1.5	2.3	*mD*
Most Likely CO_2 storage capacity	105	100	*Mt*
Reservoir lithology	Limestones, marls, sandstones, sediments	Limestones	
Caprock	Clay	Clay	

[22] Petrovskyi, O. P., Hablovskyi, B. B., Ganzhenko, N. S., & Fedchenko, T. O. (2009). Justification of the possibility of mapping oil and gas prospective objects in the conditions of the northwestern part of the Black Sea shelf on the base of seismogravity modeling.

5.1.3 CO_2 Transport

The ports of Odesa and Mykolaiv are considered as strategic CO_2 hubs and its use in the scenarios reflects current logistical constraints onshore, but still allow for the TEA to assess different offshore transport. The PIPE, SHIP and DSI scenarios are the realistic design utilizing strengths of each solution and not regarded as straightforward replacement of one transport solution by another.

PIPE explores the construction of a combined onshore–offshore pipeline system. To optimize cost efficiency and technical feasibility, a hybrid pipeline approach is proposed. An onshore pipeline would be constructed between Mykolaiv seaport and Odesa seaport, followed by an offshore pipeline extending from Odesa seaport to the Holitsyna and Shtormove offshore storage sites in the Black Sea. The total proposed pipeline length is approximately 293 km (Figure 24). While the onshore pipeline routing is optimized for realistic conditions, land use constraints represent one of the main risks associated with this scenario.

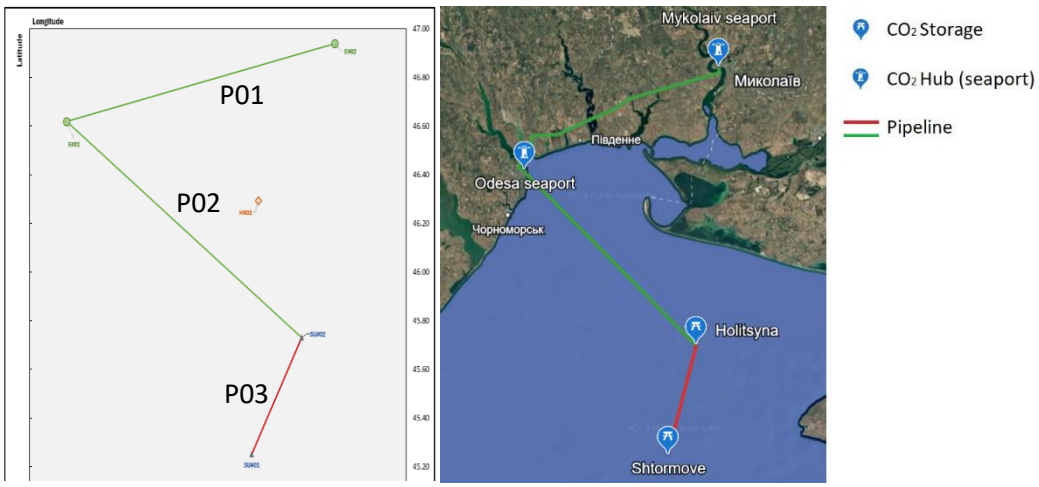


Figure 24. PIPE Scenario – Pipeline transport from Mykolaiv and Odesa ports to potential offshore storage sites in the Black Sea (pipeline in red connect the offshore injection sites).

SHIP considers the use of two conventional CO_2 ships, transporting CO_2 separately from the Odesa and Mykolaiv hubs to the Holitsyna storage site (Figure 25). Upon arrival at Holitsyna, CO_2 would be transported further to the Shtormove storage site via offshore pipeline. The total estimated realistic distance for the conventional shipping routes is approximately 290 km.

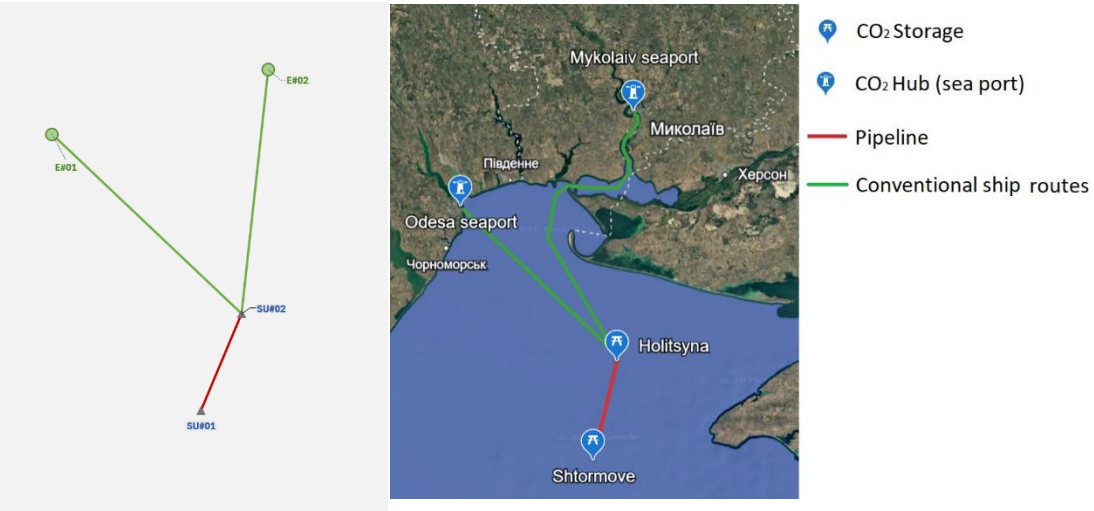


Figure 25. SHIP Scenario– Conventional ship routes from Mykolaiv and Odesa seaports to Holitsyna field, and offshore pipeline from this storage to the Shtormove storage site. (Red pipeline connects both the offshore injection sites).

DSI involves CO_2 transport using two ships with direct injection capability. In this scenario, one ship would transport CO_2 directly from the Mykolaiv hub to the Holitsyna storage site, while the second ship would transport CO_2 from the Odesa hub to the Shtormove storage site (Figure 26). The total route distance for both NEMO ship operations is estimated at approximately 335 km.

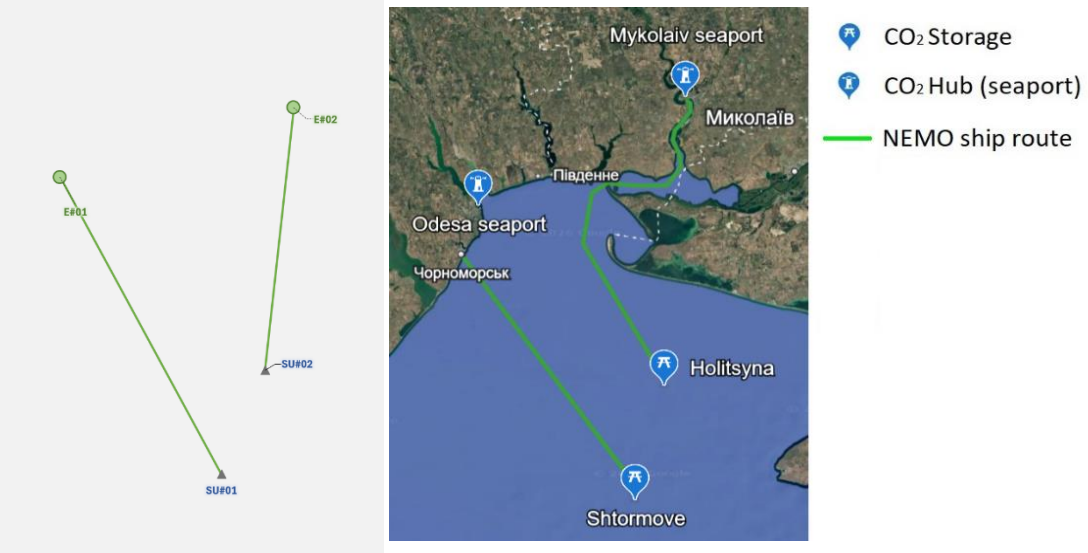


Figure 26. DSI Scenario – Two ships with Direct Injection capability transport CO2 from ports to the two storage sites.

5.2 Techno-economic assessment results

5.2.1 Capture

The Odesa and Mykolaiv clusters have a combined baseline industrial CO_2 emission rate of 3.7 $MtCO_2$/yr. Capturing this stream at a 95% capture rate generates additional process emissions from the capture plant itself, mainly driven by energy consumption, which are routed back into the capture system. The total CO_2 stream entering the capture and storage chain, therefore, averages 4.26 $MtCO_2$/yr, distributed between Odesa (1.84 $MtCO_2$/yr) and Mykolaiv (2.42 $MtCO_2$/yr). Over the 31-year scenario, this corresponds to 132.1 $MtCO_2$ captured and stored, comprising 109.0 $MtCO_2$ from industrial flue gases and 23.1 $MtCO_2$ from capture-process emissions (Table 27).

Table 27. Black Sea – Ukraine. CO_2 mass balance from the CCS chain at the capture stage.

CO_2 mass balance (2035–2065)		
Baseline industrial emissions (no CCS)	114.7	$MtCO_2$
CO_2 captured	132.1	$MtCO_2$
Biogenic CO_2 captured	0.0	$MtCO_2$
Process emissions from capture	23.1	$MtCO_2$
CO_2 stored	132.1	$MtCO_2$
Net industrial emissions with CCS	5.7	$MtCO_2$
Emission reduction (vs baseline) at the capture stage	109.0	$MtCO_2$

Costs

Capture CAPEX is 489 €M and OPEX is 275 €M/yr, expressed in real 2030 euros and undiscounted, on an overnight-cost basis. Variable OPEX, mainly electricity and thermal energy for solvent regeneration and CO_2 compression, accounts for 218 €M/yr (~79% of OPEX) and is the dominant cost component.

Because individual facilities are not modelled, these values are an aggregated regional estimate based on the sectoral reference cases in Section 2.1.

5.2.2 Transport

5.2.2.1 Scenario I – Pipeline (PIPE)

PIPE comprises one onshore and two offshore segments with a combined length of approximately 295 km (Figure 24). Compression is applied at the onshore entry points, P#01 in Mykolaiv and P#02 near Odesa, and no intermediate offshore boosters are required. Pipeline assets dominate the 414.3 €M CAPEX and 10.7 €M/yr OPEX, while pumping has a minor cost contribution with individual segments ranging of 55 km to 120 km (Table 28 and Table 29).

Table 28. Black Sea – Ukraine. PIPE scenario pipelines characteristics.

	Range	*Unit*
Total CO_2 transported per pipeline (scenario)	75–132	*Mt*
Annual CO_2 transported per pipeline	2.4–4.3	*MtCO_2/yr*
Pipeline length (individual pipelines)	55–120	*km*
Outside diameter	406–508	*mm*
Inside diameter	381–483	*mm*
Wall thickness	8.4–12.7	*mm*
Booster compression	0–20	*bar*
Inlet pressure	90–100	*bar*
Outlet pressure	87–94	*bar*

Table 29. Black Sea – Ukraine. CAPEX and OPEX of pipelines. (Values are undiscounted and represent costs in 2030 terms).

	Pipelines	**Pumping**	
CAPEX	413.1	1.2	€M
OPEX	10.1	0.6	€M/yr

5.2.2.2 Scenario II – Conventional CO_2 ship (SHIP)

SHIP uses separate routes from Odesa and Mykolaiv to a common receiving platform at Holitsyna, followed by an offshore pipeline to Shtormove (Figure 25). The offshore pipeline in this scenario, which connects the two storage units, has the same characteristics as in the PIPE scenario: it links the same points and transports the same amount of CO_2. The main difference is that pipeline operating pressure is not considered here, as it is provided locally at SU#02 rather than supplied from onshore.

Vessel sizes and schedules reflect the different route distances and volumes; using two smaller vessels on S#02 would increase cost by approximately 10% but provide greater operational redundancy. SHIP transport CAPEX is 488.4 €M and OPEX 31.1 €M/yr, with vessels dominating CAPEX and liquefaction dominating OPEX (Table 30 and Figure 27).

Table 30. Black Sea – Ukraine. Conventional ship CO_2 transport characteristics.

Ship	**S#01**	**S#02**	***Unit***
Total CO_2 transported	57.1	75.0	*Mt*
Max. CO_2 transported	1.8	2.4	*MtCO_2/yr*
Sailing distance	120	175	*km*
Number of ships	1	1	
Ship size	17,500	30,000	*tCO_2*
Loading rate	3000	3000	*tCO_2/h*
Unloading rate	500	600	*tCO_2/h*
Sailing speed	10	10	*knot*
Number of roundtrips	111	85	*per year*
Buffer storage	22,800	34,200	*tCO_2*

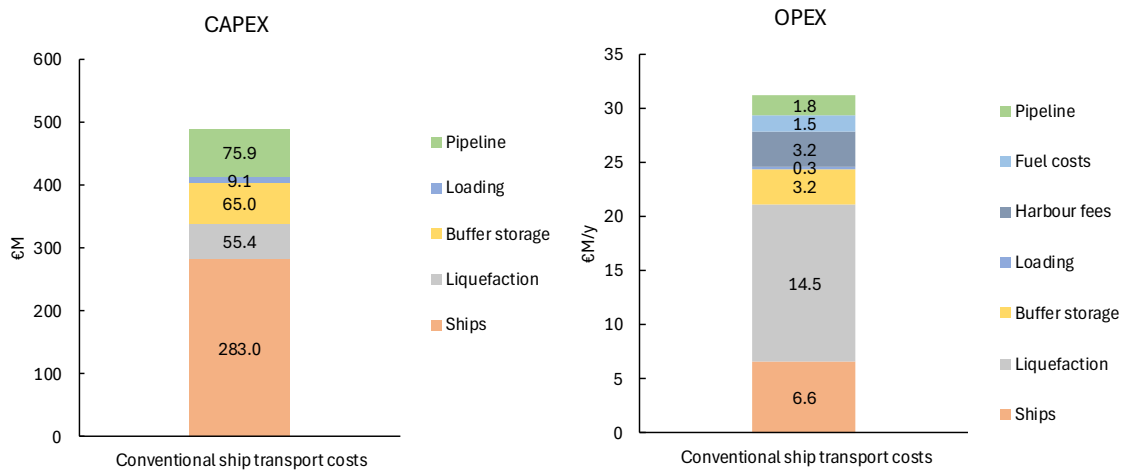


Figure 27. Black Sea – Ukraine. CAPEX and OPEX of conventional ships. (Values are undiscounted and represent costs in 2030 terms).

5.2.2.3 Scenario III – Direct ship injection (DSI)

DSI assigns each vessel directly to its corresponding storage unit, removing the central offshore hub logic. Only the Odesa route requires a longer sailing distance and a larger vessel. The additional unloading and injection equipment increases transport CAPEX to 569.9 €M and OPEX to 34.6 €M/yr, although this is partly compensated by lower storage infrastructure requirements (Table 31 and Figure 28).

Table 31. Black Sea – Ukraine. Direct injection ship CO_2 transport characteristics.

DSI	S#01	S#02	Unit
Total CO_2 transported	57.1	75.0	*Mt*
Max. CO_2 transported	1.8	2.4	*$MtCO_2/yr$*
Sailing distance	160	175	*km*
Number of ships	1	1	
Ship size	20,000	30,000	*tCO_2*
Loading rate	3,000	3,000	*tCO_2/h*
Unloading rate	500	600	*tCO_2/h*
Sailing speed	10	10	*knot*
Number of roundtrips	97	85	*per year*
Buffer storage	22,800	34,200	*tCO_2*

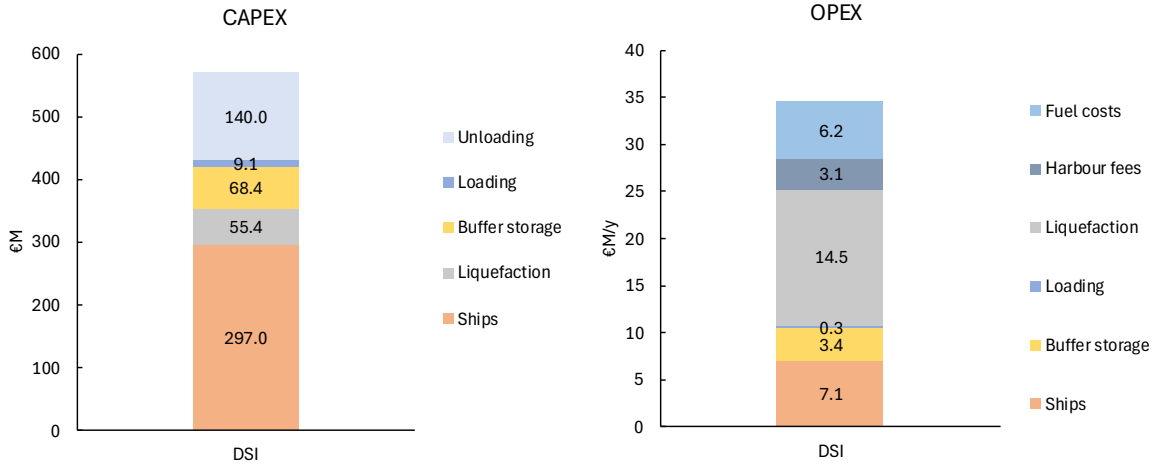


Figure 28. Black Sea – Ukraine. CAPEX and OPEX of direct injection ship. (Values are undiscounted and represent costs in 2030 terms)

5.2.3 Storage

No single storage unit has sufficient capacity for the complete project volume. The Mykolaiv stream is therefore assigned to Holitsyna and the Odesa stream to Shtormove, using five and two wells, respectively. Table 32 reports the corresponding continuous and batch-injection requirements.

Table 32. Black Sea – Ukraine. Storage parameters.

	Shtormove (SU#01)	Holitsyna (SU#02)	Unit
Annual injection rate	1.84	2.42	*$MtCO_2/yr$*
Total CO_2 stored	57	75	*$MtCO_2$*
Number of injection wells (active)	2	5	
Average injection rate per well (continuous)	117	61	*t/h*

Well and seismic costs are common to all configurations. Storage CAPEX is lowest for DSI at approximately 524 €M, followed by PIPE at 544 €M and SHIP at 829 €M; the SHIP premium results from the offshore receiving platform. OPEX excluding energy is identical at 30.5 €M/yr. Storage therefore improves the relative position of DSI but does not offset PIPE's lower transport cost (Figure 29).

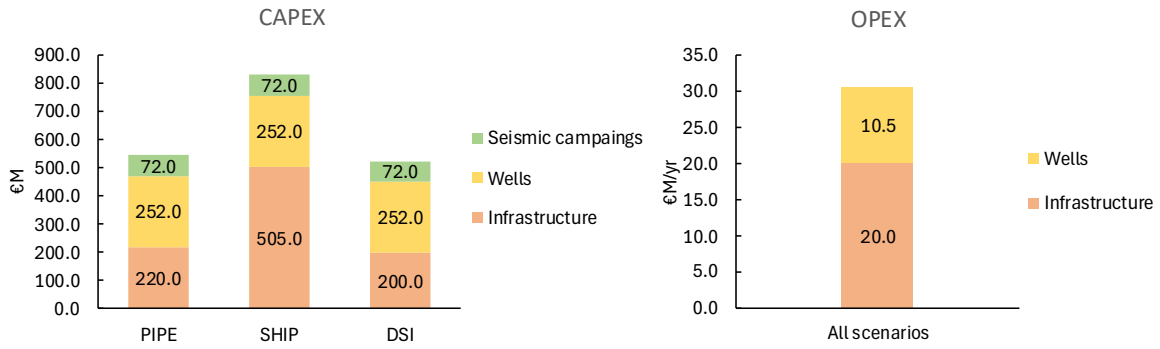


Figure 29. Black Sea – Ukraine. Storage costs excluding energy use. OPEX is identical across the three scenarios and is therefore shown as a single bar. (Values are undiscounted and represent costs in 2030 terms).

5.2.4 Energy consumption

Total energy demand is dominated by the CO_2 capture process. The energy for transport and injection is much smaller, but it differs across the three scenarios (Figure 30).

For PIPE, the transport energy requirement is very low (about 1 kWh/tCO_2 stored). By contrast, both SHIP and DSI require about 24 kWh/tCO_2 stored for transport. This higher transport demand is mainly driven by the liquefaction step in the shipping chain, since voyage ship fuel and port-time fuel account for approximately 3.6 kWh/tCO_2.

Injection energy is required for the ship-based cases only. Figure 30 shows injection energy of roughly 11 kWh/tCO_2 stored for SHIP and DSI, while PIPE assumes no additional injection energy because the pipeline delivery conditions provide sufficient pressure for injection.

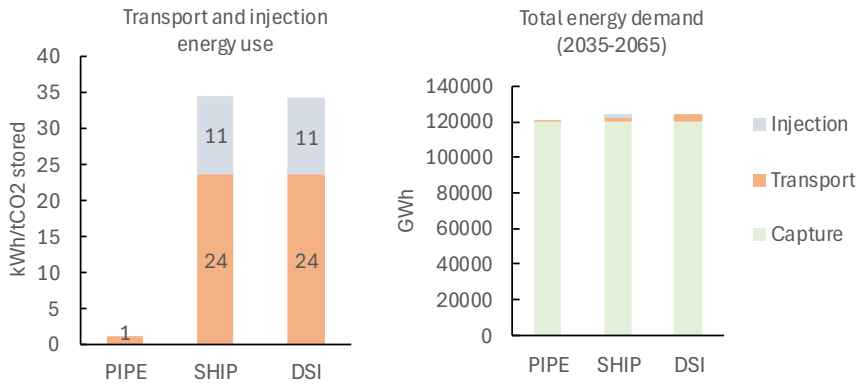


Figure 30. Black Sea – Ukraine. Left: transport and injection energy use per tonne of CO_2 stored. Right: total energy demand across the full scenario duration.

5.2.5 Transport and storage additional CO_2 emissions

Additional CO_2 emitted during transport and injection is shown in Table 33. PIPE adds only 1.5 $MtCO_2$ of extra emissions and yields net abatement of 107.5 $MtCO_2$; DSI adds 4.4 $MtCO_2$ and abates 104.5 $MtCO_2$; SHIP emits 6.0 $MtCO_2$ and abates 103.0 $MtCO_2$. The differences arise from energy demand and the carbon intensity of the energy carriers: PIPE relies solely on grid electricity for pumping and assumes no additional injection energy, while SHIP and DSI both require electricity for liquefaction, and DSI additionally consumes maritime diesel for injection.

Although Ukraine's grid electricity is relatively carbon-intensive — around twice that of maritime diesel in this assessment — the additional liquefaction and marine operations in the ship-based solutions, allow PIPE to remain the most effective option for CO_2 abatement. DSI achieves higher net abatement than SHIP despite using diesel, because its lower-carbon fuel for injection partly offsets the liquefaction penalty. All three scenarios preserve most of the capture-stage abatement benefit, confirming that downstream logistics has only a limited impact on overall CCS performance.

Table 33. Black Sea – Ukraine. Net CCS abatement by scenario, including transport and injection emissions.

	Transport & injection emissions	Net CO_2 Abated	*Unit*
PIPE	1.5	107.5	*$MtCO_2$*
SHIP	6.0	103.0	*$MtCO_2$*
DSI	4.4	104.5	*$MtCO_2$*

5.2.6 Long-term costs evaluation

PIPE has the lowest discounted full-chain cost, at 9,513 €M or 88.4 €/tCO_2 abated, followed by DSI at 10,255 €M or 98.2 €/tCO_2 and SHIP at 10,535 €M or 102.3 €/tCO_2. Capture is common to all configurations and remains the dominant cost component. (Figure 31).

Excluding capture, transport and storage cost 1,952 €M for PIPE. DSI and SHIP are approximately 38% and 52% more expensive, corresponding to 25.8 €/tCO_2 and 28.9 €/tCO_2 abated compared with 18.1 €/tCO_2 for PIPE. DSI is therefore the lower-cost maritime configuration, but it does not remove the cost advantage of the pipeline.

Figure 32 quantifies the same result: DSI is 3.10 €/tCO_2 abated cheaper than SHIP but 7.63 €/tCO_2 more expensive than PIPE. Per tonne stored, the corresponding differences are 2.11 €/tCO_2 and 5.63 €/tCO_2. DSI reduces the shipping cost penalty mainly through lower storage CAPEX.

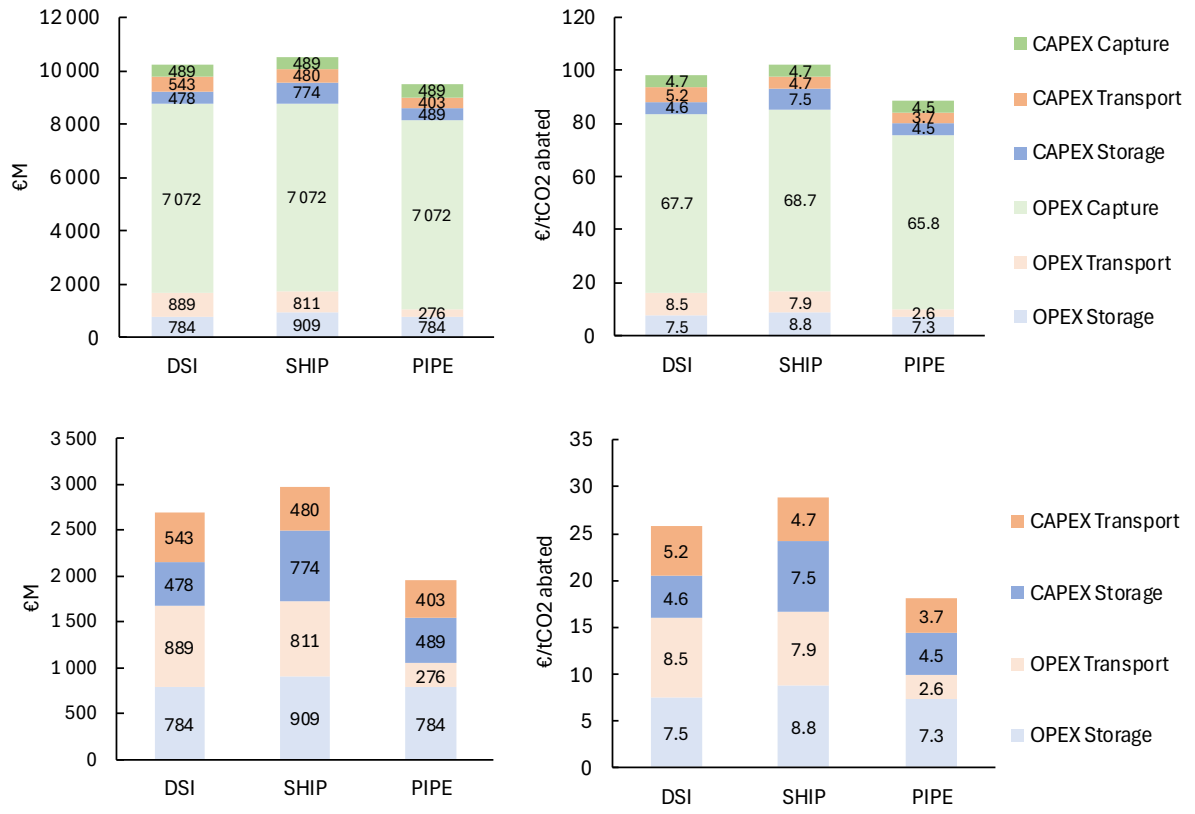


Figure 31. Black sea – Ukraine. Long-term scenarios cost assessment: absolute and specific costs per tonne of CO_2 abated (discounted, in real 2030 €).

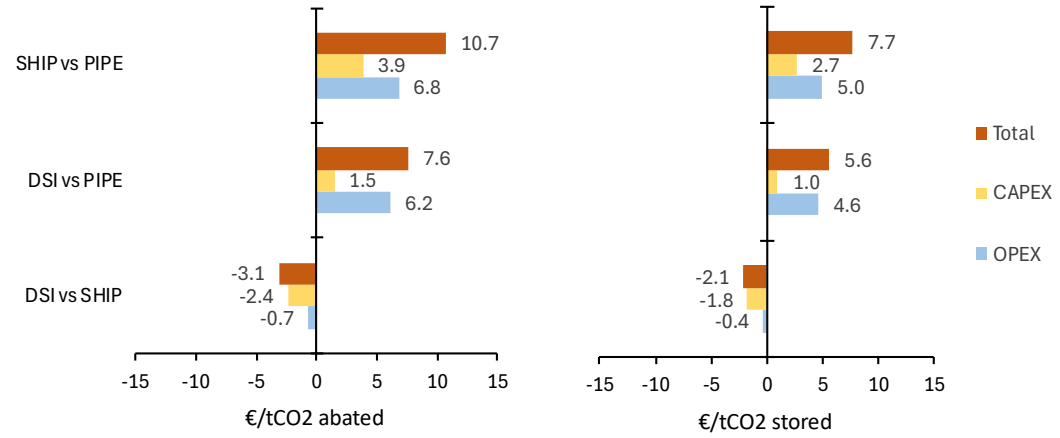


Figure 32. Black Sea - Ukraine. Transport and storage cost increment between scenarios. Positive values indicate that the first scenario listed is more expensive than the second, while negative values indicate that it is cheaper.

5.2.7 Black Sea – Ukraine conclusions

Over the 31-year scenario, the Black Sea- Ukraine scenario will capture and store 132.1 $MtCO_2$. PIPE is the lowest-cost option for the transport and storage segment, and DSI is the more cost-effective of the two ship-based configurations. Relative to PIPE, SHIP is 10.72 €/tCO_2 abated more expensive and DSI

7.63 €/tCO_2 abated more expensive; DSI therefore does not outperform PIPE on cost, but it reduces the shipping penalty by 3.10 €/tCO_2 abated compared with conventional shipping.

From an operational perspective, the CO_2 volumes and transport distances involved do not pose a significant logistics challenge for the ship-based configurations. No major bottlenecks are expected, and the system retains flexibility to accommodate alternative setups, such as smaller vessels or higher sailing speeds. For example, replacing the single 30,000 tCO_2 vessel on S#02 with two 10,000 tCO_2 vessels increases normalised cost by about 10%, but may bring operational benefits — improved redundancy, lower dependence on a single vessel, and greater resilience under adverse conditions — that the cost metric does not capture.

A relevant structural difference between SHIP and DSI lies in the offshore interface. SHIP relies on a single offshore platform receiving CO_2 from both vessels, whereas DSI delivers CO_2 directly to each injection unit. This favours the operational logic of DSI and means the two configurations are not strictly equivalent in scope. Equipping both injection sites to receive vessels was nevertheless retained as the preferred DSI configuration because it improves redundancy and reduces dependence on a centralised offshore hub, which is particularly valuable in a system exposed to vessel delays, weather interruptions, or temporary unavailability of an injection point.

Further cost reductions could in principle be achieved by phasing the development of the two storage sites, bringing them online sequentially rather than simultaneously, thereby spreading investment over time and avoiding underutilised storage infrastructure in early years. This option was not evaluated in detail and should be regarded as a potential improvement rather than a quantified result.

Overall, PIPE provides the strongest economic performance in the Ukrainian region on a normalised-cost basis. DSI emerges as the most attractive shipping-based alternative, combining a clear cost advantage over conventional shipping with operational flexibility that may prove valuable under uncertain operating conditions.

6 North Sea

The North Sea scenario was set up to evaluate techno-economic potential of direct ship injection in a gigatonne-scale value chain as well as evaluate the synergies between Norway and Denmark. It comprised of the storage sites in both countries and emitters in both, as well as several European ports serving as CO_2 source hubs. The scenario is presented in detail in the delivery D2.1[8], here the key facts are repeated and changes since D2.1 are highlighted.

6.1 Scenario overview

In the D2.1 scenario description we have presented a wide range of local emitters along the south-southwestern coast of Norway as well as central and northern coast of Jylland in Denmark. During TEA work in work package 3, this list was further refined to include largest and most likely candidates for capture activities, see next subchapter for details. In addition, 4 major North European ports with concrete CO_2-hub plans were selected as CO_2 sources. It is important to stress that our analysis does not go beyond the ports as hubs to individual emitters in Europe as it was outside of the project scope.

Four storage sites have been selected for the evaluation. While in Denmark existing fields / storage licences are considered, in Norway we focus on whole aquifers, rather than on individual storage licences. This is done as our TEA tool is not precise enough to address distribution of pore and pressure space between individual licences in the same aquifer.

As shown in Figure 33 the regional scenario may be split into four distinct clusters. The red cluster stores local emissions in Norway from Karstø and Mongstad combined with CO_2 coming from one of the European ports. The yellow cluster combine Norwegian emissions from southeast and Danish emissions form Aalborg area to store at the Inez area. The green cluster explores connection from European ports to one of the southern storage sites in Norway (Eigersund formation). The blue cluster investigates utilizing ship connection from Emden port to port of Esbjerg and existing pipeline to Greensand Harald storage area.

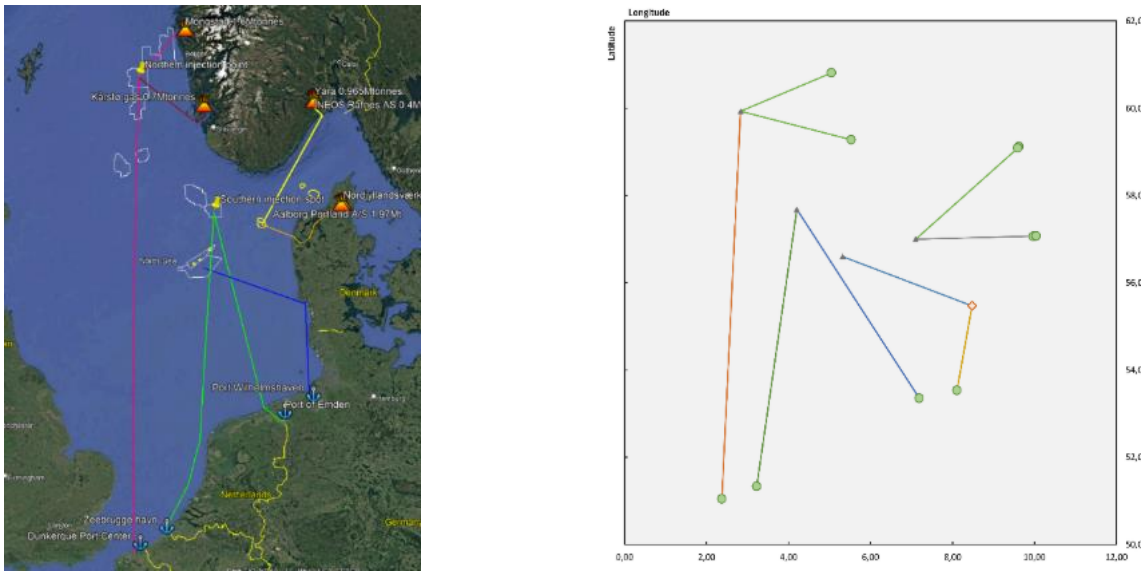


Figure 33. North Sea scenario showing clusters by transport line colours connecting CO_2 sources and sinks on top of the world map on the left and in the form of vector map on the right.

6.1.1 CO_2 Capture

The North Sea scenario has two groups of CO_2 sources: local emitters in Norway and Denmark as CO_2 capture facilities themselves, and local European ports as CO_2 sources (serving as hubs, or "virtual emitters" for in-land EU industrial capture sites). From 16 emitters in Denmark and Norway analysed before, 6 were selected for the TEA as shown in the first six rows in Table 34. Since the European ports were added as virtual emitters, with names E7 to E10 in our tool, i.e., CO_2 was collected in hubs, they provided by far the largest volume of CO_2. From the actual emitters, Aalborg Portland in Denmark and Mongstad Refinery in Norway are the largest emitters with 1.98 and 1.67 MtCO2/yr, respectively, and INEOS Rafnes chemical plant is the smallest with 0.40 $MtCO_2$/yr. None of the emitters in the scenarios have clearly indicated bio emissions.

To estimate the CO_2 capture costs and associated emissions for the European ports we have used the same methodology as in the actual emitters, resulting in a cost of approximately 60–65 €/tCO_2 at the port. Here, the actual values itself are less important as the purpose of the CTS project is on the difference between conventional and direct ship injection.

Table 34. North Sea. List of emitters considered and CO_2 emissions available for capture (forecast).

ID	EU ETS ID	Emitter Name	Cluster	Sector	Total CO_2 Emissions* ($MtCO_2$/yr)
1	NO_92	Mongstad Raffineri	Red	Oil refining	1.67
2	NO_23	Kårstø prosessanlegg	Red	Gas processing	0.73
3	NO_110	Yara Porsgrunn	Yellow	Fertilizer	0.96
4	NO_50	INEOS Rafnes	Yellow	Chemical	0.40
5	7	Aalborg Portland A/S	Yellow	Cement	1.98
6	636	Nordjyllandsværket	Yellow	Power	1.00
7		Wilhelmshavn	Green	"Virtual" emitter - port	4.00
8		Dunkerque	Red	"Virtual" emitter - port	20.00
9		Zeebrugge	Green	"Virtual" emitter - port	15.00
10		Emden	Blue	"Virtual" emitter - port	10.00
				Totals	**56.7**

* Only fossil emissions

The per sector emissions (Figure 36) are hard to analyse as each of the 6 actual facilities represent different industrial sectors. Moreover, the ports will receive the emissions from different industrial facilities upstream, so that providing a current emission for different clusters is not possible.

When comparing clusters, the red cluster that handle emissions from the two western Norwegian emitters (Mongstad and Karstø) and Dunkerque is the largest with 23.5 $MtCO_2$/yr, followed by the green comprised of Zeebrugge and Wilhelmshavn with 20 $MtCO_2$/yr and smaller blue (Emden) with 10.5 $MtCO_2$/yr and Yellow comprised of two Danish and two South-East Norwegian emitters with 4.3 $MtCO_2$/yr.

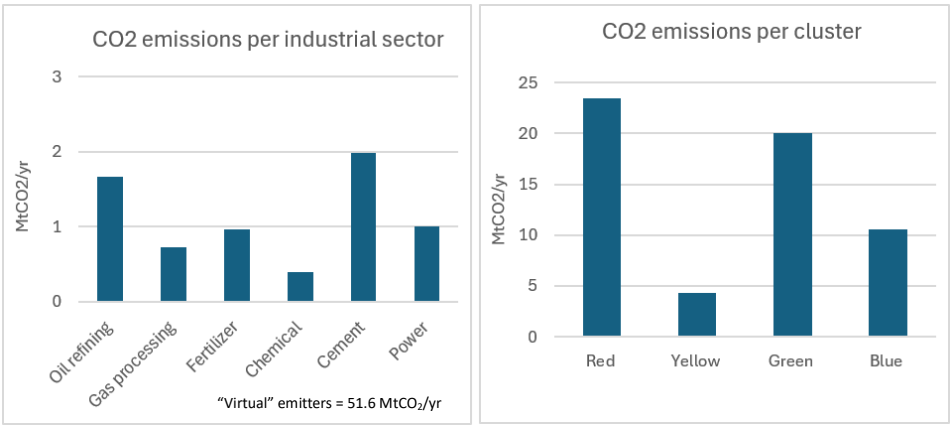


Figure 34. North Sea. Emissions considered for capture and storage per industrial sector and per cluster.

6.1.2 CO_2 Storage Sites

In D2.1 we have identified 8 storage aquifers in Norway and 8 fields in Denmark with a total capacity of over 8 Gt. For the actual TEA, two aquifers were selected in Norway (i.e., the Utsira formation, and Bryne and Sandnes formations) and in Denmark the Greensand Harald and Inez fields were used.

The Norwegian aquifers are presented in detail in Offshore Directorate's storage atlas, see Utsira[23] and Bryne / Sandnes[24] formations. Here, we will mention only the key features and peculiarities.

Utsira is a Miocene relatively shallow aquifer (ca. 750–950m depths) with excellent sand quality with more than 30% porosity and multi-Darcy permeabilities. Its potential has been proven by injection of CO_2 in the Sleipner project with more than 20 $MtCO_2$ injected since 1996. It has a relatively low salinity water of app. 30,000 ppm and can store on the scale of 1 $GtCO_2$.

The Bryne and Sandnes formation is deeper at 1.6–3.0 km storage depth, hotter and with a significantly more saline pore water. Storage in Lower Jurassic high-quality sands potentially exceeding Utsira with expected storage capacity of up to 2 $GtCO_2$.

In our scenario the volumes injected in each of the formations do not exceed 1 $GtCO_2$, well within the prospective capacity and leaving space for mid and small-size emitters to be added if full scale injection becomes a reality.

The top depth map of Utsira (left) and Bryne and Sandnes (right) formations, courtesy of Offshore directorate storage atlas, are shown in Figure 35.

[23] Norwegian Petroleum Directorate. (2014). The Bryne and Sandnes formations. In CO_2 storage atlas: Norwegian Continental Shelf. Link: The Bryne and Sandnes formations – CO_2 Storage Atlas
[24] Norwegian Petroleum Directorate. (2014). *The Utsira and Skade aquifer*. In *CO_2 storage atlas: Norwegian Continental Shelf*. Link: The Utsira and Skade aquifer – CO_2 Storage Atlas

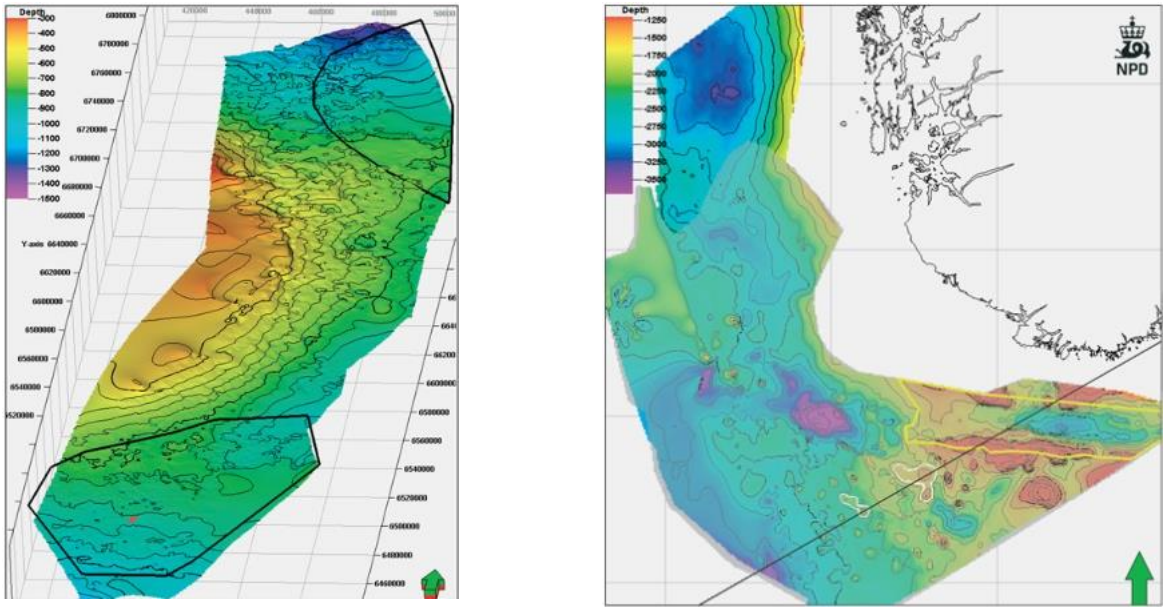


Figure 35. North Sea. Top depth map of Utsira (left) and Bryne and Sandnes (right) formations from Norwegian Offshore directorate CO_2 storage atlas.

6.1.2.1 Danish storage sites

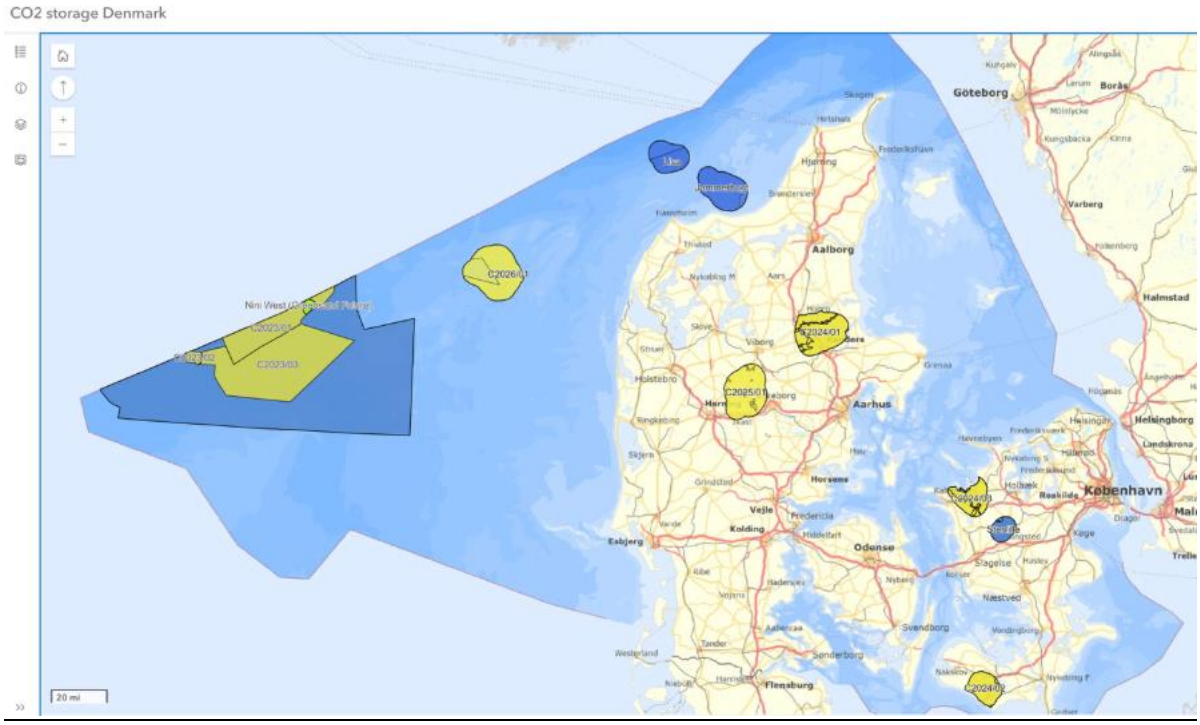
Denmark has issued multiple offshore and onshore CO_2 storage licences in recent years, see Figure 36; the two offshore sites considered in this study are Harald and Inez projects. Harald is a deep depleted gas-field reservoir system in the western Danish North Sea. It consists of Middle Jurassic sandstone at around 3.4–3.6 km depth and Danian–Upper Cretaceous chalk at roughly 2.7 km depth, both with proven sealing capacity from millions of years of hydrocarbon retention. Regional studies show porosities >20% and high permeabilities in the sandstone units, supporting efficient CO_2 injectivity.

Inez is a near-shore saline aquifer about 50–55 km off North Jutland, targeting a sandstone reservoir at ~1.8 km depth. A six-year exploration licence issued in 2026 focuses on confirming injectivity and caprock quality; early operator assessments suggest up to ~10 Mt/yr storage potential from around 2035. This site represents Denmark's expanding portfolio of dedicated aquifer storage options, complementing the depleted-field capacities such as Harald.

6.1.3 CO_2 Transport

Two transport scenarios will be evaluated here. Ships are used in all connections in the North Sea scenario, except for a repurposed pipeline from Esbjerg to Harald area. So, in both scenarios, a fundamental approach for CO_2 delivery into the North Sea remains the same – CO_2 is transported by ships to the injection sites. In Scenario I, injection infrastructure is placed on platforms in the North Sea. One can argue subsea infrastructure being cheaper and favourable, however, it comes with the question of wellheads access. The exact decision on the type of infrastructure to be used will be taken on individual project level. Here, we compare fixed CO_2 handling infrastructure in Scenario I, while the direct ship injection will be handled in Scenario II.

The blue cluster (ship from Emden to Esbjerg and then pipeline from Harald) will therefore remain the same in both direct injection and conventional ship scenarios. The total pipeline length is 372 km.


CO2 storage Denmark
Göteborg
Aalborg
Aarhus
København
Esbjerg
Odense
Kolding
Vejle
Horsens
Flensburg
Sønderborg
Svendborg
Helsingborg
Halmstad
Varberg
Borås
Roskilde
Næstved
Slagelse
Frederikshavn
Hjørring
Skagen
Viborg
Holstebro
Grenaa
Frederikssund
Helsingør
Landskrona
Trelleborg
Malmö
Kungsbacka
Kinna
Ringkøbing
Skjern
Grindsted
Vejle
Fredericia
Hillerød
Kalundborg
Kalundborg
Ringsted
Kalundborg
Kalundborg
Kalundborg

Overall sailing distances in the scenario is nearly 5,000 km with 32 ships servicing the routes.

6.2 Techno-economic assessment results

6.2.1 Capture

Figure 34 shows the mass of CO_2 captured annualy per emitter, totalling 65.4 MtCO2/yr including additional process CO_2 emissions from capture.

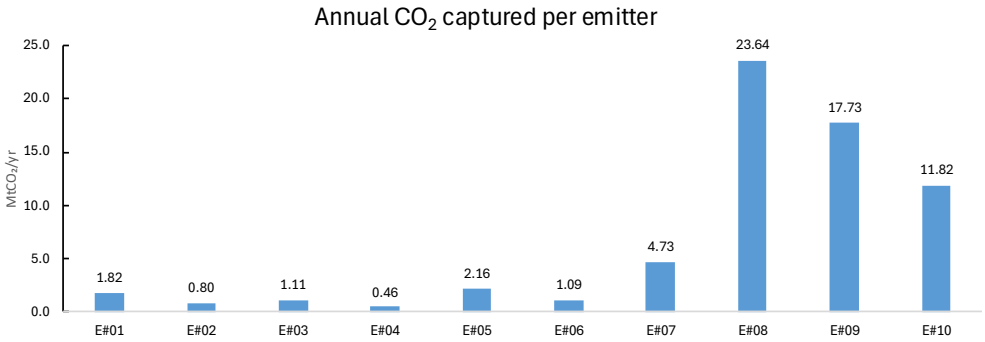


Figure 34. North Sea. Annual CO_2 captured and stored per industrial facility.

Table 35 shows the no-CCS baseline and the corresponding capture-stage mass balance. Since the scenario represents a high-level evaluation, it was considered that all emitters start capturing CO_2 at the same time, totalling to 65.4 $MtCO_2$/yr, of which about 57.9 $MtCO_2$/yr originates from the four European port hubs. The biogenic emissions were not considered due to the same reason presented in the scenario description.

In the current scenario over 1,728 $MtCO_2$ would be emitted without CCS. A total of 2,026 $MtCO_2$ is captured and stored because emissions generated by the capture process are also captured. Net emissions with CCS are 101 $MtCO_2$, equating to an emissions reduction of 1,627 $MtCO_2$ (Table 35).

Table 35. North Sea scenario. CO_2 mass balance from the CCS chain at the capture stage.

CO_2 mass balance (2035–2065)		
Baseline industrial emissions (no CCS)	1,728	*$MtCO_2$*
CO_2 captured	2,026	*$MtCO_2$*
Biogenic CO_2 captured	0	*$MtCO_2$*
Process emissions from capture	399	*$MtCO_2$*
CO_2 stored	2,026	*$MtCO_2$*
Net industrial emissions with CCS	97	*$MtCO_2$*
Emission reduction (vs baseline) at the capture stage	1,631	*$MtCO_2$*

6.2.2 Transport

Both conventional carriers and direct injection ones are using the same routes and, for the sake of comparison, same loading / unloading capacity. That means that routing, time in transit, loading and unloading time and, therefore, ship capacities and sizes will be the same. It may be argued that CO_2 handling and injection facilities may be designed and optimized differently if they are placed on the ship or platform / subsea, however, this level of detail seems premature for the North Sea scenarios. The key differences will therefore come from cost of permanent infrastructure on the storage sites, OPEX and energy costs. Overview of the shipping routes is given in Table 36.

Table 36. North Sea scenarios transport characteristics.

Shipping routes:	#01	#02	#03	#04	#05	#06	#07	#08	#09	#10	Unit
Total CO_2 transported	56.5	24.7	34.4	48.7	67	101	137	515	344	687	*Mt*
Max. CO_2 transported	1.8	0.8	1.1	1.6	2.2	3.3	4.4	16.6	11.1	22.2	*$MtCO_2/yr$*
Sailing distance	220	300	5	500	5	210	226	1250	1000	1250	*km*
Number of ships	1	1	1[a]	1[a]	2[b]	2[b]	2	8	6	12	-
Ship size	20	10	23	23	20	20	13	50	40	50	*$ktCO_2$*
Loading rate	3	3	3	3	3	3	3	3	3	3	*$ktCO_2/h$*
Unloading rate	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.0	0.75	0.75	*$ktCO_2/h$*
Sailing speed	14	14	14	14	14	14	14	14	14	14	*knot*
Number of roundtrips	96	84	72	72	90	90	187	44	49	40	*per ship annually*
Buffer storage	22.8	11.4		26.2		45.6	29.7	456	274	684	*$ktCO_2$*

[a] *Routes #03 and #04 use the same ship;* [b] *Routes #05 and #06 use the same two ships.*

It is also important to state that an approach to optimizing ship schedules will be further developed and discussed in WP4.

6.2.2.1 Scenario I – Conventional CO_2 carriers (SHIP)

In the conventional carriers scenario, the bulk CAPEX lie in the ship costs themselves (7.9 out of 10.7 €B) while the main OPEX is liquefication (215 out of 608 €M per year). The findings here are well aligned with conventional carriers scenarios in other regions. It is also important to highlight that large size of the ships is dictated not only by the volumes transported, but also by the navigational conditions in the North Sea, when utilization of smaller ships will affect regularity. The storage CAPEX and OPEX of SHIP scenario are presented in Figure 37.

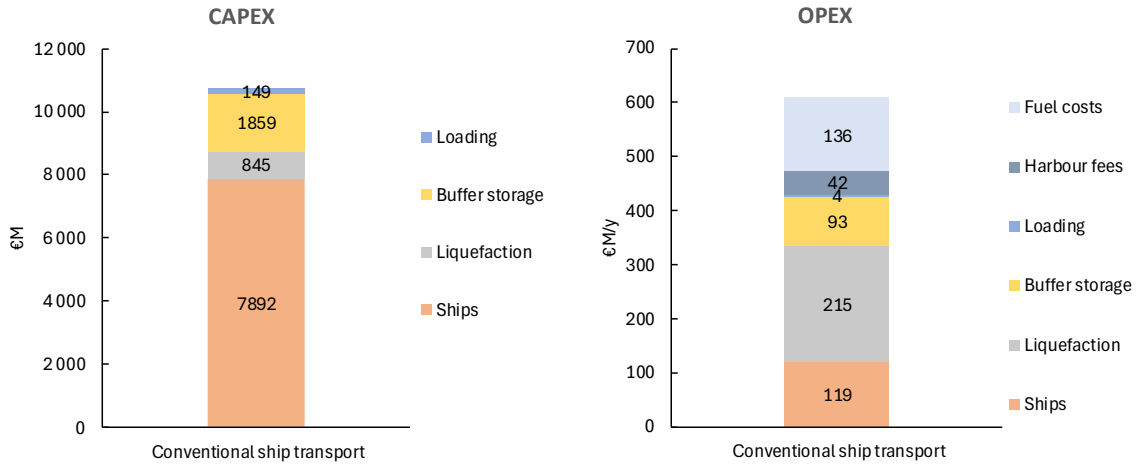


Figure 37. North Sea. CAPEX and OPEX of conventional ship solution. (Values are undiscounted and represent costs in 2030 terms).

6.2.2.2 Scenario II – Direct Ship Injection (DSI)

In DSI scenario the ship themselves get more expensive due to construction and installation of unloading facilities on them (additional 2.4 €B) and the fuel costs becomes dominating in the OPEX growing to 280 €M per year. Increased costs in transport will be offset by reduction in CAPEX and OPEX of storage infrastructure. The CAPEX and OPEX of DSI scenario are presented in Figure 38.

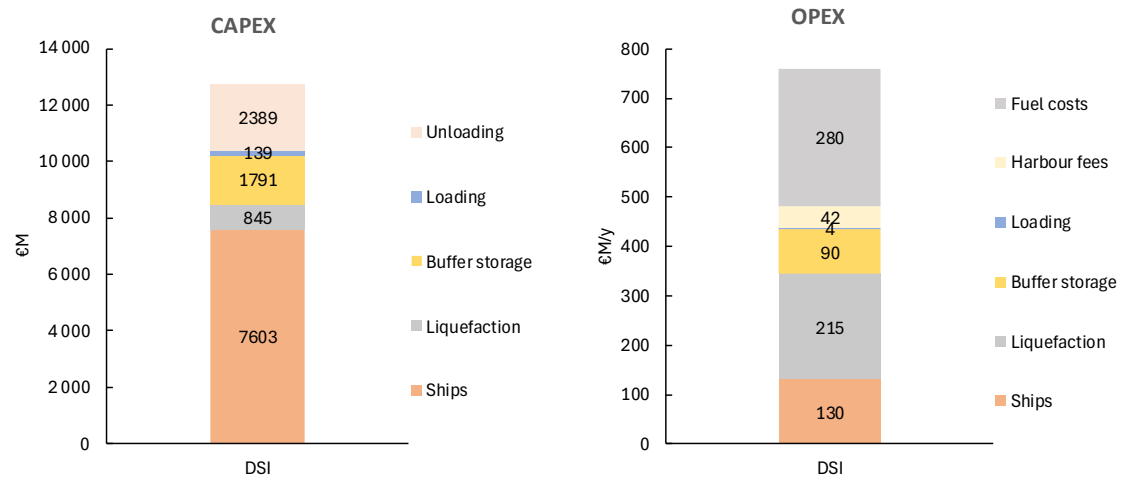


Figure 38. North Sea. CAPEX and OPEX of direct injection ship. (Values are undiscounted and represent costs in 2030 terms).

6.2.3 Storage

Each of the clusters is built around a single storage site. Again, in Norwegian North Sea, we are looking into aquifers rather than separating them into licenses. Two smaller storage sites store slightly below 5.0 $MtCO_2/yr$ (4.82 $MtCO_2/yr$ in SU#02 and 4.72 $MtCO_2/yr$ in SU#03), two large ones 26.3 $MtCO_2/yr$ (SU#01) and 29.6 $MtCO_2/yr$ (SU#04). Key storage site parameters are presented in Table 37 and Figure 39.

Table 37. North Sea scenario. Storage parameters.

	SU#01	SU#02	SU#03	SU#04	Unit
Annual injection rate	26.26	4.82	4.73	29.55	*$MtCO_2/yr$*
Total CO_2 stored	814	149	147	916	*$MtCO_2$*
Number of injection wells (active)	9	5	6	20	
Average injection rate per well (continuous)	333	110	89	170	*t/h*

For both North Sea scenarios CAPEX for the wells and seismic campaigns are the same in 1781 €M and 1660 €M, respectively, with the CAPEX saving of 4.73 €B due to direct ship injection as significantly less infrastructure is needed to be built offshore. OPEX values are the same as the energy use for storage is handled separately in the following subchapter.

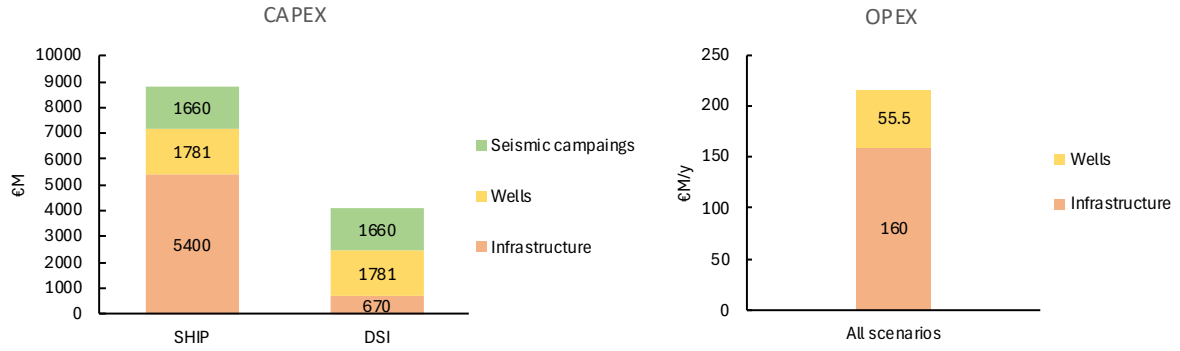


Figure 39. North Sea. Storage costs excluding energy use. OPEX is identical across the scenarios and is therefore shown as single bar. (Values are undiscounted and represent costs in 2030 terms).

6.2.4 Energy consumption

Capture remains the most energy demanding process with the same amount of energy required to transport and inject CO_2 in DSI and SHIP scenarios (Figure 40). The difference comes from where the energy is used: all of it on the vessels for DSI scenario and some of it on the vessel (transport) and installations (injection) for SHIP scenario. The effect of the cost of energy and associated emissions – from gas turbine or land with umbilical for permanent installations vs. ship engine (diesel with or without CCS vs., for example, ammonia) need to be carefully analysed and concluded upon outside the scope of the CTS project.

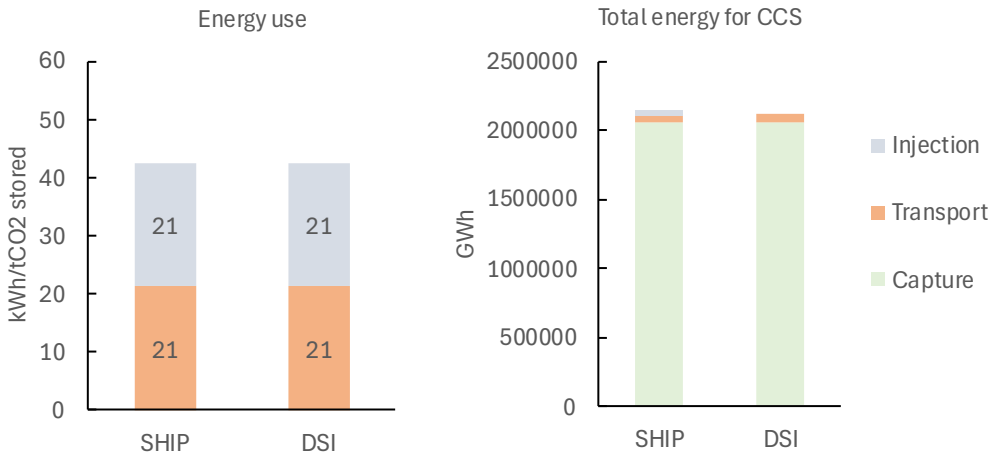


Figure 40. North Sea scenario. transport and injection energy use per tonne of CO_2 stored. Right: total energy demand across the full scenario duration.

6.2.5 Transport and storage additional CO_2 emissions

The additional emissions associated with transport and storage are presented in Table 38. The increase in associated emissions in DSI scenario highlights low energy footprint in Norway and Denmark if electricity can be used for fixed installations to heat and inject CO_2. Indeed, in both regions the associated emissions with electricity production are below 100 gCO_2e/kWh dropping as low as 20 in Norway compared to 500–600 gCO_2e/kWh in marine engines (567 gCO_2e/kWh is used in our calculations). Note the net abated CO_2 stored is higher for the conventional SHIP system, due to the reduced need for marine diesel consumption when injecting over the CCS period.

Table 38. North Sea. Net CCS abatement by scenario, including transport and injection emissions.

	Transport & injection emissions	Net CO_2 Abated	*Unit*
SHIP	24.6	1,607	*$MtCO_2$*
DSI	69.7	1,561	*$MtCO_2$*

6.2.6 Comparison and segments analysis

Both scenarios show very close costs per ton CO_2 abated (Figure 41). However, there are important differences:

1. DSI allows for significant CAPEX reduction for storage sites: 4.8 €B or 53%
2. CAPEX for the carrier fleet increases by 2.1 €B providing overall gain on transport and storage CAPEX.
3. OPEX for capture and transport for DSI is higher by app. 0.5 €B higher as decrease in storage OPEX is overcome by increase in transport one.

4. As associated emissions in DSI scenario are higher (due to higher footprint for kWh with diesel than with electricity) the amount of CO_2 abated decreases. This causes costs per ton CO_2 abated to grow across the whole value chain. While DSI is almost 2.2 €B cheaper in overall costs and 1.1 €/tCO_2 stored cheaper than SHIP scenario (ca 3.3% cheaper) it ends up being more expensive per ton abated (Figure 42). The "negative" effect would disappear if energy for CO_2 capture on fixed installation would come from gas turbines, rather than electricity on shore, which have comparable energy footprint to marine diesel of around 500 gCO_2/kWh. Alternatively, on-board capture facilities or alternative fuels for direct injection ships could be used reducing its associated emissions.

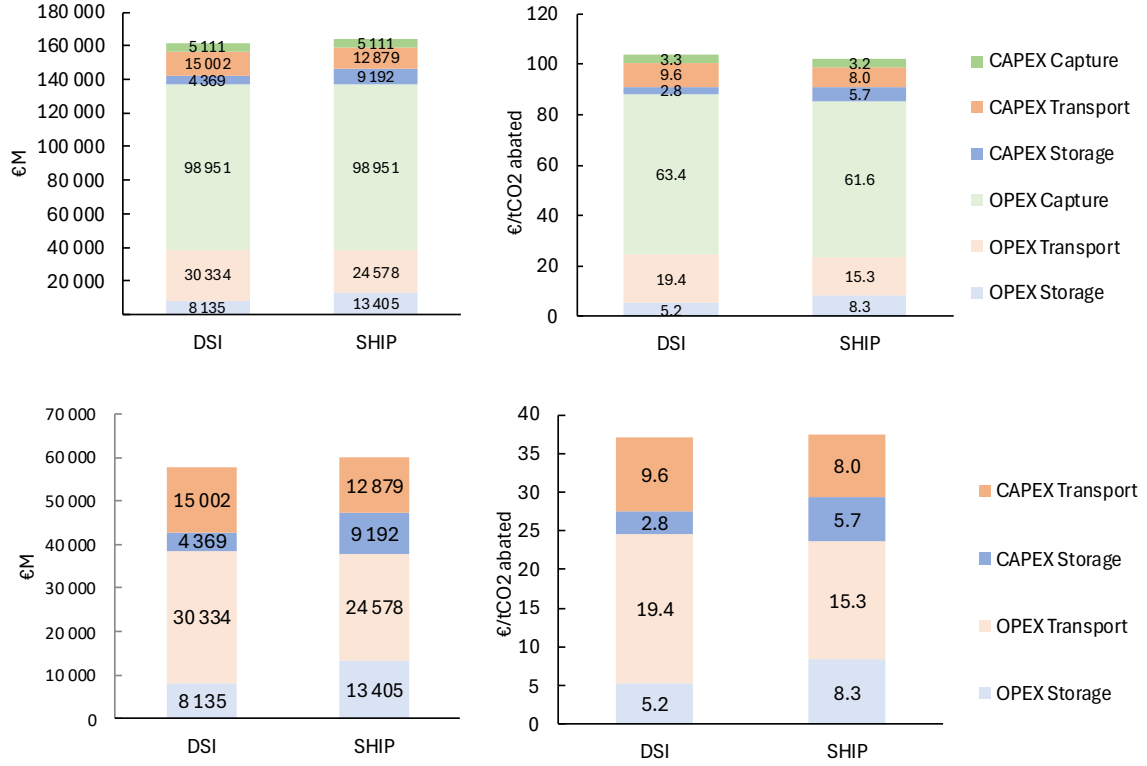


Figure 41. North Sea. Long-term scenarios cost assessment: absolute (left) and specific costs per tonne of CO_2 abated (right) for Capture, storage and transport together (top) and for transport and storage separately (bottom). Costs are discounted, in real 2030 €.

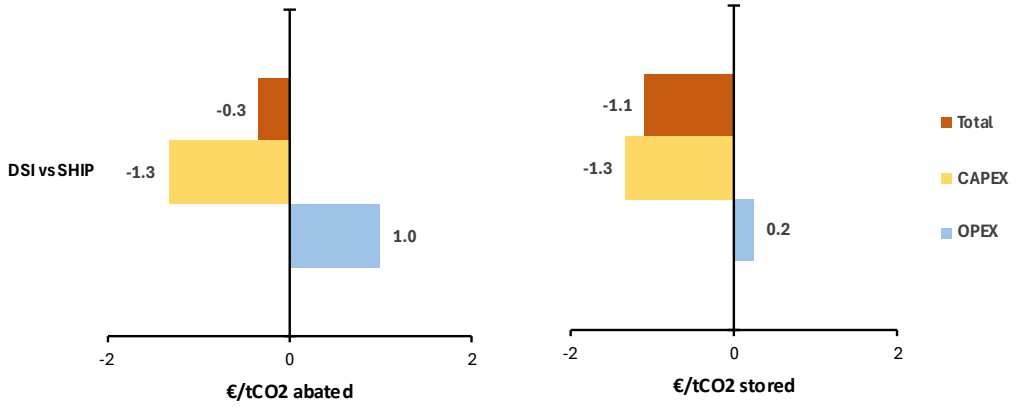


Figure 42. North Sea. Transport and storage cost increment from SHIP to DSI per tonne CO_2 abated (left) and per tonne CO_2 stored (right).

Additional analysis was performed on red, green and yellow clusters (Figure 33). The key difference between them is “yellow” being relatively small distance local emitters, “green” EU ports based – i.e. large distance, big volumes and “red” combination of both.

Yellow cluster is clearly the most expensive per ton stored reaching 133 €/tCO_2 avoided for DSI and 144 for SHIP scenarios. It, however, clearly shows benefits of direct ship injection by reducing storage CAPEX and OPEX from 14 €/tCO_2 and 15 €/tCO_2 correspondingly for SHIP to 5 €/tCO_2 and 12 €/tCO_2 with small increase in transport costs from 4 €/tCO_2 CAPEX and 13 €/tCO_2 OPEX to 5 €/tCO_2 and 15 €/tCO_2 for SHIP.

Long distance, high volumes “green” case favours conventional carrier scenario with increase of cost from 63 €/tCO_2 avoided for conventional carriers to 67 €/tCO_2 avoided for DSI. The unit cost is significantly lower than for “yellow” cluster showcasing economy of scale storing 916 MtCO_2 in “green” scenario compared to 149 in “yellow”. The unit cost of storage in “green” scenario is fairly low therefore, while relative cost reduction for storage is 22% (compared to 32% for “yellow” segment) it is only 1.4 €/tCO_2, which is overrun by increase in DSI CAPEX and OPEX.

“Red” segment lands in the middle combining local and EU port-based sources with 75 €/tCO_2 costs for both DSI and SHIP scenarios.

6.2.7 North Sea scenario – conclusions

From the regions studied in CTS, the North Sea has the largest stored volumes by far. However, it takes a more “birds-eye view” approach to both capture and storage using 4 EU ports in addition to local emissions and evaluating aquifers in Norway as a whole, rather than on the license basis.

DSI is approximately 1.35% cheaper in absolute full-chain cost and approximately 3.7% cheaper in absolute transport and storage costs and per tonne stored. However, when considering costs per tonne abated DSI is 4.3 €B cheaper for transport and storage components.

For the large volumes of CO_2 transported over large distances, liquefication / warm-up costs as well as associated emissions using ship engines become significant. The scenario is, however, rather unfavourable for DSI where diesel emissions (500-600 gCO_2e/kWh for DSI) are compared to using energy from one of the greenest grids in Europe with a scale of 30-80 gCO_2e/kWh for SHIP scenario. In case the energy for storage comes from gas turbines offshore or onboard capture or alternative ship engine fuel (such as ammonia) is used the results could be quite different. Nevertheless, for large volumes over large distances a pipeline might become a viable solution again especially if it can be laid along existing corridors.

For locally based “smaller” yellow segment DSI is clearly advantageous with significant savings for transport and storage part of the value chain.

The scenarios have not been further optimised for ship, loading and injection infrastructure. Further steps in reducing associated footprints could thus be taken.

7 Atlantic Coast – Portugal

The Atlantic Coast of Portugal scenario was defined considering: i) the national decarbonisation policies and targets; ii) CCUS scenarios and evaluations from previous studies; iii) emitters manifestation of interest in CCUS; and iv) emitters or clusters that may take advantage of DSI technology. The scenario presented below is based on the one presented in D2.1[26] but updated following a preliminary TEA and emissions forecasting for the industrial sources. Changes are mainly related with the industry sectors considered for CO_2 capture and the forecast of emissions from each facility.

7.1 Scenario overview

The key documents driving Portugal's national decarbonisation strategy are the National Energy and Climate Plan (PNEC 2030)[27]; the Carbon Neutrality Roadmap 2050 (RNC 2050)[28]; the National Hydrogen Strategy (EN-H2)[29]; and the Portuguese Climate Law (DL98/2021)[30]. In the 2024 revision of PNEC 2030 the carbon neutrality is set to be achieved by 2045, CCUS is also mentioned as an essential technology to help Portugal achieve its decarbonisation target in hard-to-abate industries where reducing emissions is challenging (e.g. Cement) and where other forms of decarbonisation might be more difficult or less effective. Furthermore, CO_2 utilisation may be an option related to the production of low-carbon hydrogen and other sustainable fuels. Bioenergy with carbon capture and storage (BECCS) is also pointed as possibly relevant for the pulp and paper and waste to energy sectors, which would lead to negative CO_2 emissions.

The Portuguese scenario considers CO_2 capture in 14 emitters, mostly located along the country's western coast (Figure 43). The scenarios consider capturing and storing a maximum of 9.4 $MtCO_2/yr$ of CO_2 from 2045 onwards, which amounts to the CO_2 expected to be available in the 14 facilities considering the evolution of the different sectors and different decarbonisation options. Biogenic emissions are a very significant component of the total CO_2 available, with around 2/3 of those being considered for permanent geological storage, resulting in negative emissions, and the remainder being utilised for production of synthetic fuels. When referring to biogenic emissions, the TEA considers only the CO_2 that will be injected for permanent storage.

Storage will be in an offshore reservoir located at around 22 km from Figueira da Foz. The initial injection structure is a smooth anticline designated as Q4-TV1 in a deep saline aquifer composed by siliciclastic layers of the Torres Vedras Group (Early Cretaceous), locally known as the *Figueira da Foz Group,* at a top reservoir depth of 820–1178 m below sea level and with thickness of around 340 m.

The TEA considers, as the base-case (PIPE) transport through a pipeline network and that links to an offshore trunkline south from the Figueira da Foz.

The alternate scenario (DSI) combines pipeline with transport by ship with direct injection capabilities from emitters near the Sines and Setúbal ports. Transport for all other emitters proceed as in the PIPE scenario.

[26] Mesquita, P., Carneiro, J., Madureira, P., Pereira, P. (2025). Chapter 7—Western Coast of Portugal *in* Shogenova, A., Shogenov, K., & Usta, M. (2025). CTS D2.1—Report on clusters created.
[27] República Portuguesa. (2024). *Plano Nacional Energia e Clima 2030 (PNEC 2030) — Atualização*. Resolução do Conselho de Ministros n.º 149/2024, de 30 de outubro [National Energy and Climate Plan 2030 — Update].
[28] República Portuguesa. (2019). Roteiro para a Neutralidade Carbónica 2050 (RNC 2050): Estratégia de longo prazo para a neutralidade carbónica da economia portuguesa em 2050 [Roadmap for Carbon Neutrality 2050].
[29] República Portuguesa. (2020). *Estratégia Nacional para o Hidrogénio (EN-H2)* [National Hydrogen Strategy].
[30] Assembleia da República. (2021). *Lei n.º 98/2021, de 31 de dezembro: Lei de Bases do Clima* [Climate Framework Law].

7.1.1 CO_2 Capture

An analysis was made to forecast the amount of CO_2 available for capture from the 24 emitters identified in D2.1, based on projected manufacturing demand and sectoral growth, as well as sectoral, national, and company-specific roadmaps. The methodology pursued for that forecast is described in Annex B. The glass and chemical sectors analyses resulted in lesser emissions in the long term when compared with present values and, therefore, facilities in these sectors were not included in the CCS scenarios. As a result, from the original list of 24 emitters only 14 were carried to the TEA (Figure 43).

Energy from the biomass sector, namely from CELBI Figueira facility, had previously been treated as independent from the pulp and paper facilities but are now integrated with the respective industrial facility and aggregated into the Pulp and Paper sector. Together, the Cement, Pulp and Paper, Waste-to-Energy and Oil Refining sectors are forecasted to produce in the long-term up to 9.36 $MtCO_2/yr$ that can be captured. From this total, approximately 38%, or 3.57 $MtCO_2/yr$, are fossil- and process-based, while the remaining 62%, or 5.79 $MtCO_2/yr$, originate from biogenic sources.

The Pulp and Paper and Waste-to-Energy sectors consider e-fuels production as a priority for the use of biogenic CO_2. However, given the energy constraints to produce large amounts of e-fuels, 70% of the available biogenic emissions will be considered for geological storage contributing to negative emissions[31].

With regards to the scenario previously presented in D2.1, four clusters are now considered (Figueira, Leiria, Lisboa, Setúbal), supplemented by five isolated sources too distant from any other capture location (Figure 43).

Table 39. Atlantic Coast – Portugal. List of emitters considered in the Atlantic Coast of Portugal scenario and CO_2 emissions considered for capture (forecast up to 2050).

ID	EU ETS ID	Emitter Name	Cluster	Sector	Fossil+Process CO_2 $MtCO_2/yr$	Biogenic CO_2 $MtCO_2/yr$	CO_2 emissions $MtCO_2/yr$
1	196	Petrogal	Isolated emitter	Oil refining	0.72	0.12	0.84
2	291	Navigator Figueira	Figueira	Pulp & paper	0.02	1.21	1.24
3	277	Navigator Setúbal	Setúbal	Pulp & paper	0.02	1.12	1.14
4	48	CELBI Figueira	Figueira	Pulp & paper	0.00	1.54	1.54
5	145	Navigator Cacia	Isolated emitter	Pulp & paper	0.00	0.76	0.76
6	173	CIMPOR Alhandra	Lisbon	Cement	0.39	0.06	0.44
7	174	CIMPOR Souselas	Isolated emitter	Cement	0.40	0.05	0.45
8	102	SECIL Outão	Setúbal	Cement	0.67	0.12	0.79
9	103	SECIL Maceira-Liz	Leiria	Cement	0.34	0.07	0.41
10	-	Lipor	Isolated emitter	Waste to energy	0.21	0.21	0.41
11	-	Valorsul	Lisbon	Waste to energy	0.35	0.38	0.74
12	79	Lhoist	Leiria	Cement	0.29	0.12	0.42
13	202	CIMPOR Loulé	Isolated emitter	Cement	0.10	0.01	0.12
14	104	SECIL Pataias	Leiria	Cement	0.06	0.01	0.07
				Totals	**3.57**	**5.79**	**9.36**

[31] The costs of capturing and transporting CO_2 for e-fuels production are not considered in the TEA analysis for CCS.

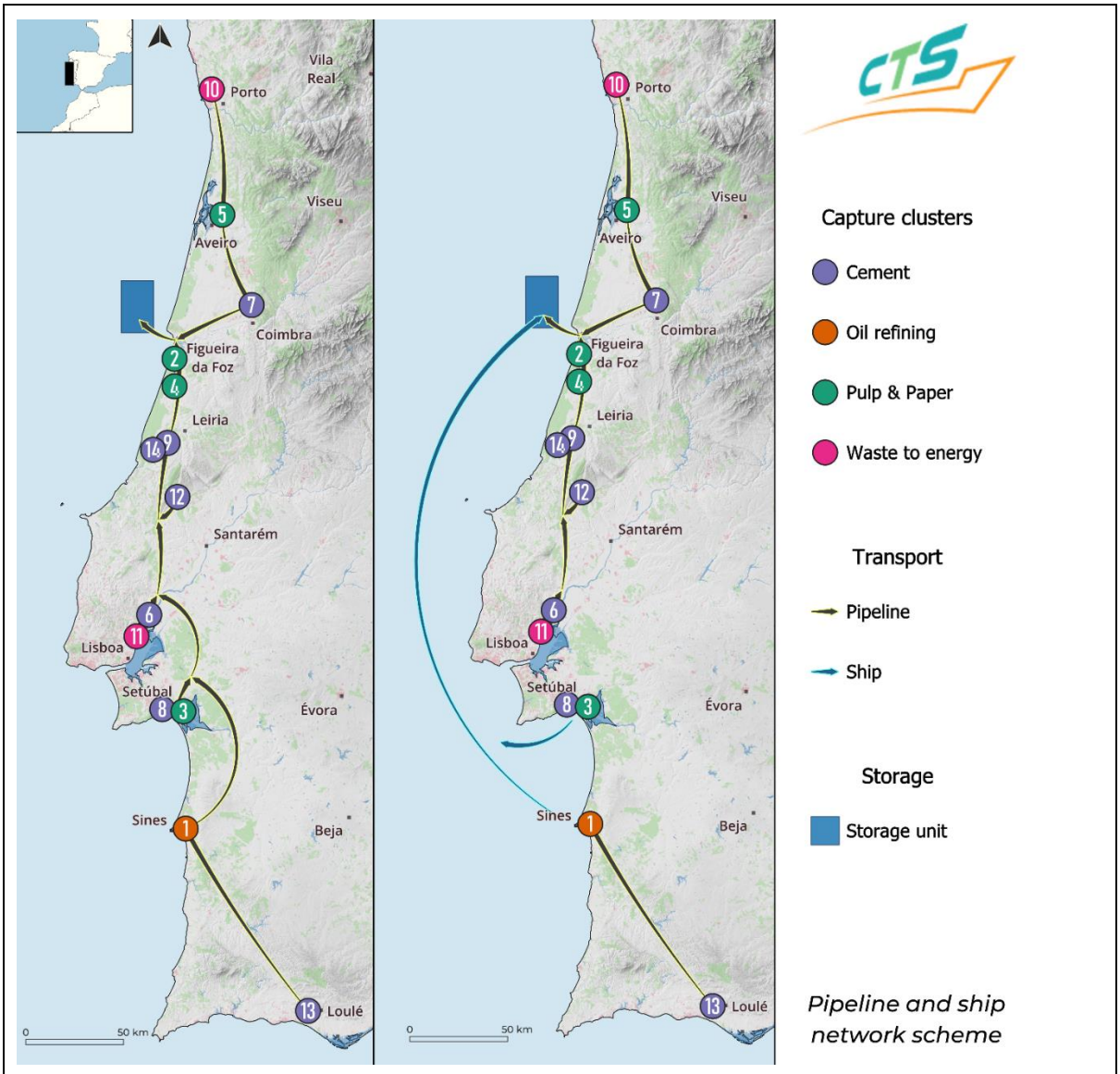


Figure 43. Atlantic Coast – Portugal. Left: Clusters and transport flow for PIPE scenario; Right: Clusters and transport flow for DSI scenario.

The pulp and paper sector is the largest contributor to biogenic emissions, accounting for approximately 4.64 $MtCO_2$/yr allocated to geologic storage. In contrast, 63% (2.25 $MtCO_2$/yr) of fossil and process emissions are associated with cement clinker production. The significant reduction with respect to current emissions reflects the industry efforts to increase the use of alternative materials, reduce clinker content in cement, and adopt biofuels and alternative technologies. Another major contributor is oil refining at the Sines facility, which accounts for approximately 0.84 $MtCO_2$/yr, representing 9% of total CO_2 emissions. The company's emission reduction targets are primarily driven by reduced reliance on fossil-derived hydrogen with projected investments on large scale electrolysers, process upgrades, and other decarbonisation measures.

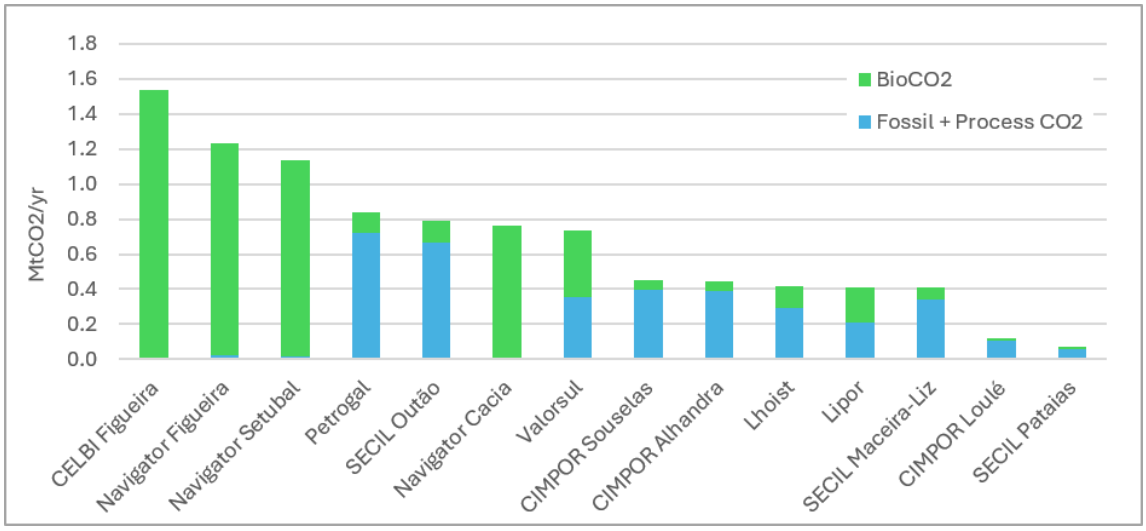


Figure 44. Atlantic Coast – Portugal. Emissions considered for capture and storage per industrial facility.

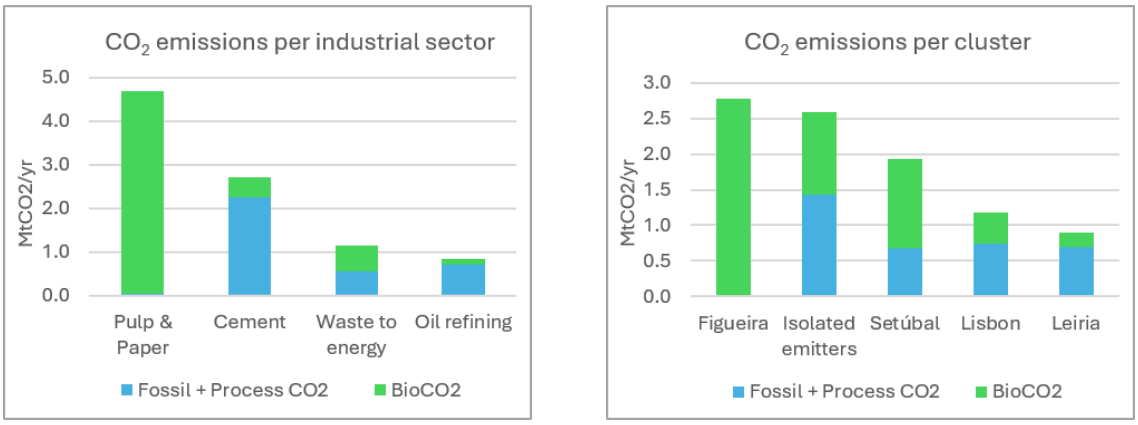


Figure 45. Atlantic Coast – Portugal. Emissions considered for capture and storage per industrial sector and per cluster.

7.1.2 CO_2 Storage site

The initial storage site is located in the Northern sector of the Lusitanian Basin, approximately 22 km offshore from Figueira da Foz port (Figure 46). The identification and selection of this storage site, a geological structure defined as a smooth anticline shape, designated as Q4-TV1, resulted from the subsurface geo-characterization studies conducted within the scope of the PilotSTRATEGY project.

The storage site is a deep saline aquifer composed of siliciclastic deposits of the Torres Vedras Group (locally designated the Figueira da Foz Group) which serves as the reservoir. It is capped by carbonates and marls of the Cacém Formation (locally known as Costa de Arnes Formation), acting as the primary seal.

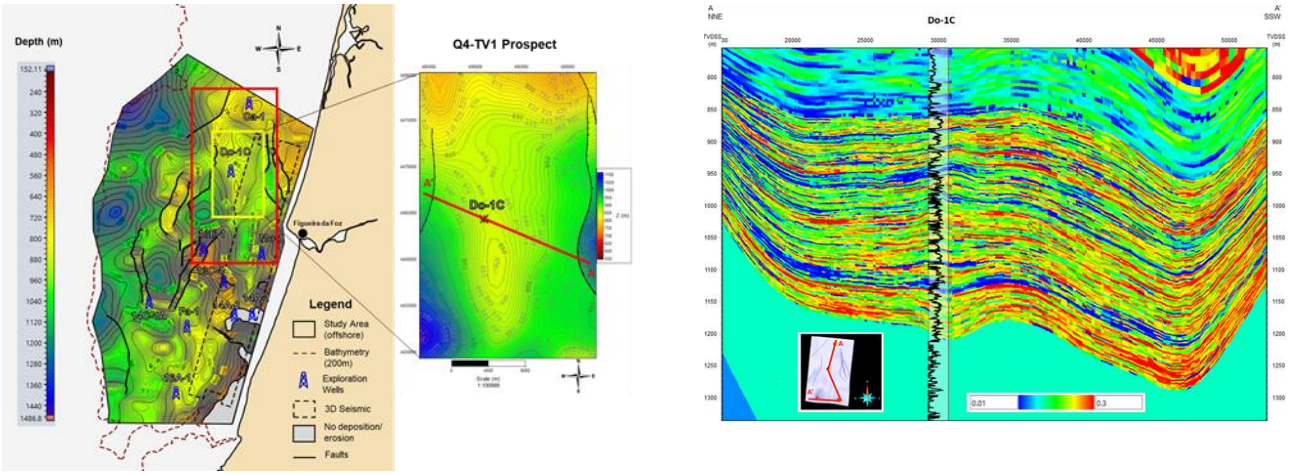


Figure 46. Atlantic Coast – Portugal. Left: Map of the top of the Torres Vedras Group reservoir structure illustrating the outlines of the study area of the 3D static model's boundary (red rectangle) and the reservoir model boundary covering the area of the Q4-TV1 prospect (yellow rectangle). Right: A realisation of the stochastic simulation of effective porosity is shown in a cross-section of the static model for the reservoir region at the structure of the Q4-TV1 prospect.

The storage capacity values resulted from the net-porous volumes (conservative, most likely optimistic values) of the reservoir conducted in the static model (Table 40). The selection of Q4-TV1 as the initial site considered the possibility to upscale the CO_2 storage to other structures in the same deep saline aquifer, located at around the same distance from the coast. Since the characterisation of those structures/sites is beyond the scope of CTS project, the storage costs in any such structure are regarded as similar to those of the Q4-TV1 injection site.

Table 40. Atlantic Coast – Portugal. Reservoir parameters for the CO_2 storage site at structure Q4-TV1.

Parameters Q4-TV1	Value	Unit
Depth of reservoir top [a]	820–1178	m
Reservoir Net-Porous Volume[b]	658–727/709	m^3 ($x10^7$)
CO_2 density	580	kg/m^3
Salinity	56	g/L
Permeability[c]	5–1,541/122	mD ($10^{-15}m^2$)
Porosity[c]	8–32/11	%
Temperature	42	°C
Storage efficiency factor[b]	3.1–10/6.1	%
Optimistic CO_2 storage capacity	421	Mt
Conservative CO_2 storage capacity	123	Mt
Most Likely CO_2 storage capacity	251	Mt

[a] (min-max); [b] (Conservative - Optimistic/ Most Likely); [c] (min-max/avg)

The injection well is designed with a wellhead at seabed, roughly 85m below sea level, and with a maximum injection capacity of up to 1 $MtCO_2$/yr and two open hole intervals: 1,025 m – 1,065 m and 1,155 m – 1,205 m below sea level.

Further details regarding the geology of the storage site and the location of the injection well are provided in the D2.1 of CTS and in deliverables of PilotSTRATEGY[32,33]. Currently, the PilotSTRATEGY

[32] Pereira, P., Caeiro, M.H., Carneiro, J., Khudhur, K., Ribeiro, C., Lopes, A.M., Santos, M. & Marques da Silva, D. (2024). Lusitanian Basin (Portugal). In Bouquet, S. (Ed.), Report on static modelling with uncertainties. Deliverable WP3/D3.2, EU H2020 PilotSTRATEGY project 101022664 report, 105-139.

[33] Khudhur, K., Pereira, P., Carneiro, J., Hardwick, J., Santos, M. & Casacão, J. (2024). Lusitanian Basin (Portugal). In Chassagne, R. (Ed.), Report on storage capacity optimization. Deliverable WP3/D3.3, EU H2020 PilotSTRATEGY project 101022664.

models long-term CO_2 behaviour and containment at Q4-TV1, assessing trapping, site integrity, and fault-reactivation risks.

7.1.3 CO_2 Transport

The long-term scenarios include testing the transport exclusively by pipeline (scenario PIPE) and compare it with the transport and injection directly from ship for the Sines and Setúbal regions (scenario DSI) (Figure 43).

For the PIPE scenario, around 700 km of new dedicated CO_2 pipelines are expected to connect all CO_2 emitters. The spatial distribution of the emitters and the existing natural gas pipeline network have a strong synergy and could allow CO_2 pipelines to be built in the existing pipeline corridors.

The DSI scenario uses the Sines and Setúbal ports as hubs. The Sines port aggregates the CO_2 from the Petrogal refinery (0.84 $MtCO_2$/yr), located in the vicinity of the port, and the Loulé cement plant (0.12 $MtCO_2$/yr), located 150 km south from Sines, and connected to it by an onshore pipeline.

The Setúbal cluster has two emitters, a Pulp and Paper plant (Navigator) and a cement factory (Outão), aggregating 1.93 $MtCO_2$/yr of CO_2; although both facilities have dedicated docking ports, they are also at distances up to 6 km from the Port of Setúbal.

7.2 Techno-economic assessment results

7.2.1 Capture

Figure 47 shows expected annual capture by facility, including CO_2 generated and recaptured by the capture system. Deployment occurs at five-year intervals with three facilities being activated in 2035, nine in 2040 and two in 2045. Once all facilities are operating, capture reaches 11.2 $MtCO_2$/yr (also accounting for additional CO_2 production from the capture process). CELBI Figueira (1.87 $MtCO_2$/yr), Navigator Figueira (1.50 $MtCO_2$/yr), Navigator Setúbal (1.38 $MtCO_2$/yr) and Petrogal (1.03 $MtCO_2$/yr) account for about 5.78 $MtCO_2$/yr, just over half of the total; CIMPOR Loulé (0.12) and SECIL Pataias (0.08) are the smallest contributors.

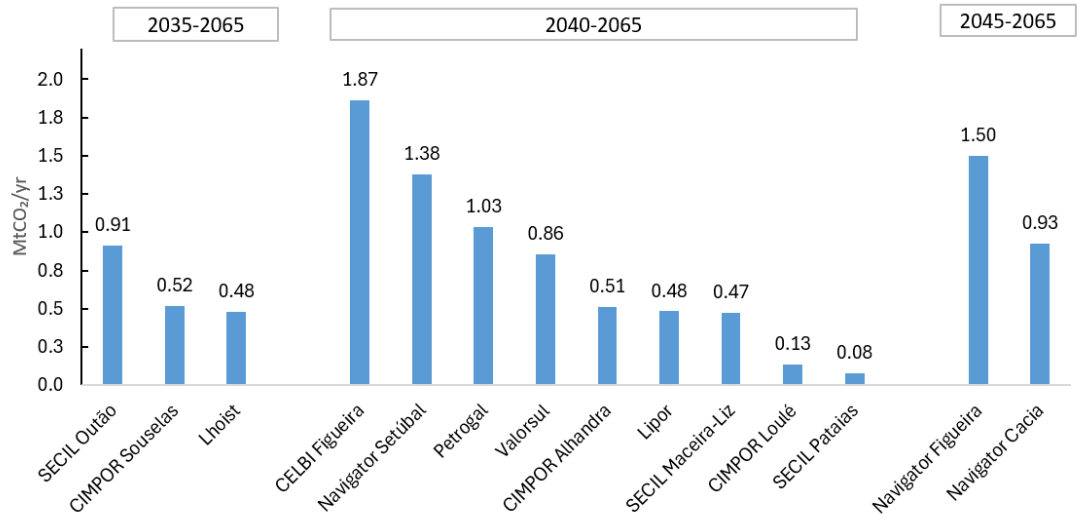


Figure 47. Atlantic Coast – Portugal. Annual CO_2 mass captured per emitter and the respective timeframe.

Under the considered forecast emissions to be captured and over the scenario timeframe for each facility, the 14 industrial facilities would release 241.7 $MtCO_2$ to the atmosphere in a no-CCS baseline.

Deploying CCS changes this picture substantially. Across the scenario period, a total of 287.4 $MtCO_2$ is captured and permanently stored, of which 135.2 $MtCO_2$ is biogenic CO_2 and 57.7 $MtCO_2$ is generated by the capture process; the remainder is captured process- and fossil-origin industrial CO_2. Residual uncaptured emissions from the industrial facilities fall to 12.1 $MtCO_2$ over the full period, equivalent to an emission reduction of 229.7 $MtCO_2$ at the capture stage compared with the no-CCS baseline (Table 41).

Table 41. Atlantic Coast – Portugal. CO_2 mass balance from the CCS chain at the capture stage.

CO_2 mass balance (2035–2065)		
Baseline industrial emissions (no CCS)	241.7	$MtCO_2$
CO_2 captured	287.4	$MtCO_2$
Biogenic CO_2 captured	135.2	$MtCO_2$
Process emissions from capture	57.7	$MtCO_2$
CO_2 stored	287.4	$MtCO_2$
Net industrial emissions with CCS	12.1	$MtCO_2$
Emission reduction (vs baseline) at the capture stage	229.7	$MtCO_2$

7.2.2 Transport

7.2.2.1 Scenario I – Pipeline (PIPE)

The PIPE configuration comprises 19 onshore segments totalling approximately 674 km and a 26 km offshore connection to the storage site (Figure 43). The network combines short feeder lines with longer regional corridors and operates in dense phase using compression at the entry points, without intermediate booster stations. Table 42 provides the dimensions, pressure conditions and transported volumes for each segment.

Table 42. Atlantic Coast – Portugal. PIPE scenario pipelines characteristics.

	Range	Unit
Total CO_2 transported per pipeline (scenario)	2.1–287.4	*Mt*
Annual CO_2 transported per pipeline	0.1–11.2	*$MtCO_2$/yr*
Pipeline length (individual pipelines)	1.5–131	*km*
Outside diameter	127–508	*mm*
Inside diameter	114–483	*mm*
Wall thickness	6.3–12.7	*mm*
Booster compression	20–40	*bar*
Inlet pressure	100–120	*bar*
Outlet pressure	86–109	*bar*

The network requires approximately 522.6 €M of CAPEX and 15.9 €M/yr of OPEX. Pipeline assets dominate the initial investment, while pumping has a larger relative contribution to operating expenditure. The configuration is therefore a capital-intensive regional backbone with comparatively low recurring transport cost (Table 43).

Table 43. Atlantic Coast – Portugal. CAPEX and OPEX of pipelines. (Values are undiscounted and represent costs in 2030 terms).

	Pipelines	**Pumping**	
CAPEX	510.9	11.7	€M
OPEX	12.2	3.7	€M/yr

Economically, the onshore pipelines show strong economies of scale. CAPEX per kilometre is highest in dense, short connections (P04 at 4.87 €M/km, P06 at 4.42 €M/km) and lowest in long, thin lines (P09 and P19 below 0.55 €M/km). Despite its offshore nature and higher CAPEX intensity (4.28 €M/km), its very high mass flow makes it one of the cheapest pipelines in the system on a unit basis

(0.39 €/tCO_2; 0.01 €/km/tCO_2), confirming that volume, more than onshore/offshore status, is the dominant driver of cost-effectiveness in this network.

7.2.2.2 Scenario II – Direct ship injection (DSI)

DSI uses two routes from Setúbal and Sines to the storage site, with sailing distances of approximately 300 and 320 km (Figure 43). Setúbal is one of Portugal's main multipurpose ports, surrounded by a diversified industrial base, including cement and pulp and paper factories that constitutes a strong cluster of point-source emitters. Sines, in turn, is the deepest deep-water port in the country and a key energy hub on the Iberian Atlantic façade, hosting a LNG terminal, which makes it particularly well-suited for large-scale CO_2 shipping operations.

The Setúbal route has higher transport capacity and operational throughput, while the Sines route operates at a smaller scale with proportionally reduced infrastructure requirements. Table 44 provides the vessel, schedule, transfer-rate and buffer-storage assumptions for both routes.

Table 44. Atlantic Coast – Portugal. Direct injection ship CO_2 transport characteristics.

Ship	S#01	S#02	*Unit*
Total CO_2 transported	64.1	30.4	*Mt*
Max. CO_2 transported	2.3	1.2	*$MtCO_2/yr$*
Sailing distance	300	320	*km*
Number of ships	1	1	
Ship size	40,000	25,000	*tCO_2*
Loading rate	2,500	1,500	*tCO_2/h*
Unloading rate	500	250	*tCO_2/h*
Sailing speed	14	12	*knot*
Number of roundtrips	60	50	*per year*
Buffer storage	45,885	28,500	*tCO_2*

Figure 48 presents the cost structure. DSI transport CAPEX is approximately 661.6 €M and OPEX 34.6 €M/yr. Vessels dominate the investment, while liquefaction, ship operation and fuel account for about 80% of recurring costs. The cost structure shows that the DSI premium results mainly from maritime assets and operations rather than from storage development.

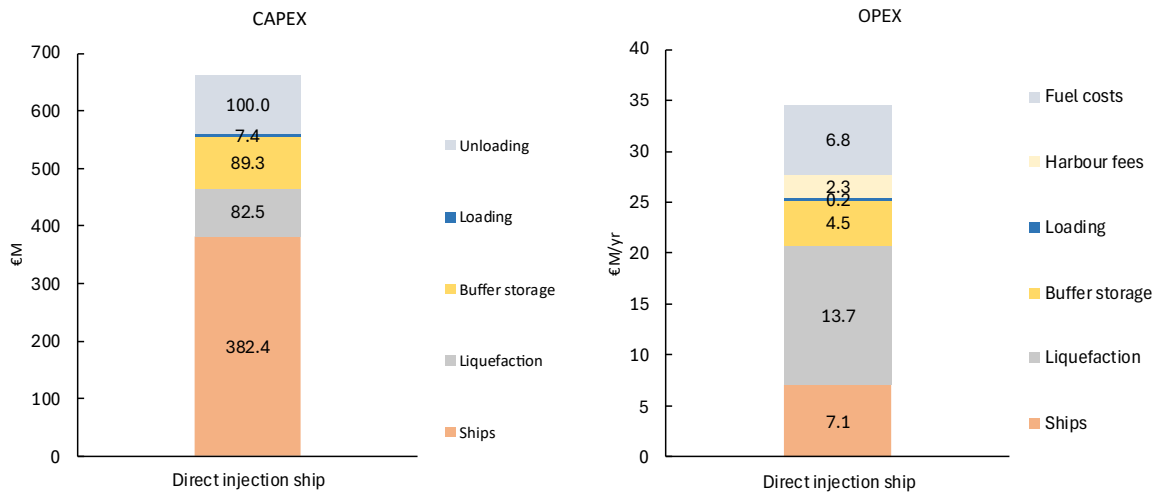


Figure 48. Atlantic Coast – Portugal. CAPEX and OPEX of direct injection ship. (Values are undiscounted and represent costs in 2030 terms).

7.2.3 Storage

The storage system accommodates 287.4 $MtCO_2$ through staged development from two active wells in 2035 to twelve wells at the plateau rate of 11.2 $MtCO_2$/yr from 2045, supplemented by four backup wells. The average continuous injection rate remains approximately 107–110 tCO_2/h per well; batch operation would require higher rates depending on the vessel duty cycle (Table 45). As described in section 7.1.2, Q4-TV1 is the initial storage but other structures in the same deep saline aquifer, in the northern sector of the Lusitanian basin, will be required to store such an amount of CO_2 until 2065. Those structures have been identified but not characterised in detail comparable to Q4-TV1. Thus, these results reflect Q4-TV1 storage costs and are assumed similar for the other structures.

Well deployment follows a phased schedule aligned with the ramp-up of CO_2 injection: during the initial phase (2035–2040), only 2 wells are active, supporting an injection rate of 1.91 $MtCO_2$/yr; a first expansion occurs in 2040, when the number of wells increases to 9 and the injection rate rises to 8.73 $MtCO_2$/yr; and a second expansion takes place in 2045, when the full configuration of 12 wells is reached, sustaining the plateau injection rate of 11.15 $MtCO_2$/yr until 2065. As with the previous regions scenarios, batch-injection operation would increase the per-well rates to roughly double or more, depending on the duty cycle imposed by ship arrivals and buffer storage management.

Table 45. Atlantic Coast – Portugal. Storage parameters.

	Q4-TV1 (SU#01)	Unit
Annual injection rate	1.9–11.2	*$MtCO_2$/yr*
Total CO_2 stored	287 *	*$MtCO_2$*
Number of injection wells (maximum active)	2–12	
Number of backup wells	4	
Average injection rate per well (if continuous)	107–110	*t/h*

**Considering the utilisation of already identified structures other than Q4-TV1.*

Well and seismic costs are common to PIPE and DSI and dominate storage expenditure. Storage CAPEX is approximately 868 €M for PIPE and 892 €M for DSI, a difference of about 3%, while OPEX is identical at 34 €M/yr excluding energy. Storage therefore does not determine the scenario ranking; the difference arises primarily from transport economics (Figure 49). Hence, wells are the main driver for both storage CAPEX and OPEX, while the choice between PIPE and DSI has only a marginal storage cost impact and should be guided primarily by technical, operational, and risk considerations.

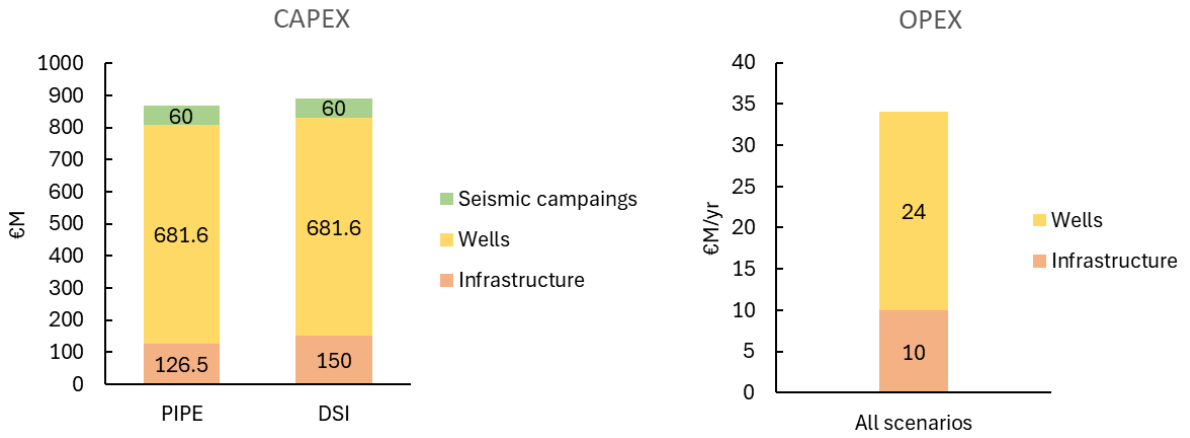


Figure 49. Atlantic Coast – Portugal. Storage costs excluding energy use. OPEX is identical across both scenarios and is therefore shown as a single bar. (Values are undiscounted and represent costs in 2030 terms).

7.2.4 Energy consumption

The energy breakdown of the CCS chain shows that capture is overwhelmingly the dominant consumer in both configurations, accounting for nearly the entirety of the ~300,000 GWh required from 2035 to 2065 (Figure 50).

Energy requirements for transport and injection are comparatively minor, yet they reveal meaningful differences between PIPE and DSI. In the PIPE configuration, downstream energy use is limited to roughly 5 kWh/tCO_2 stored, entirely attributable to transport through the pipeline network, as the pressure delivered at the pipeline outlet is sufficient to inject the CO_2 directly into the reservoir. The DSI configuration reaches around 22 kWh/tCO_2 stored, evenly split between transport and injection. Within the transport share, approximately 9 kWh/tCO_2 corresponds to fuel consumed during ship voyages and port operations, with the remaining 2 kWh/tCO_2 linked to the fraction of CO_2 that is still transported by pipeline. The injection component reflects the need to re-pressurise the liquefied CO_2 offshore before injection. Although DSI is four times more energy-intensive than PIPE on a downstream basis, this gap is diluted for the full chain, given the large energy requirements for the capture stage.

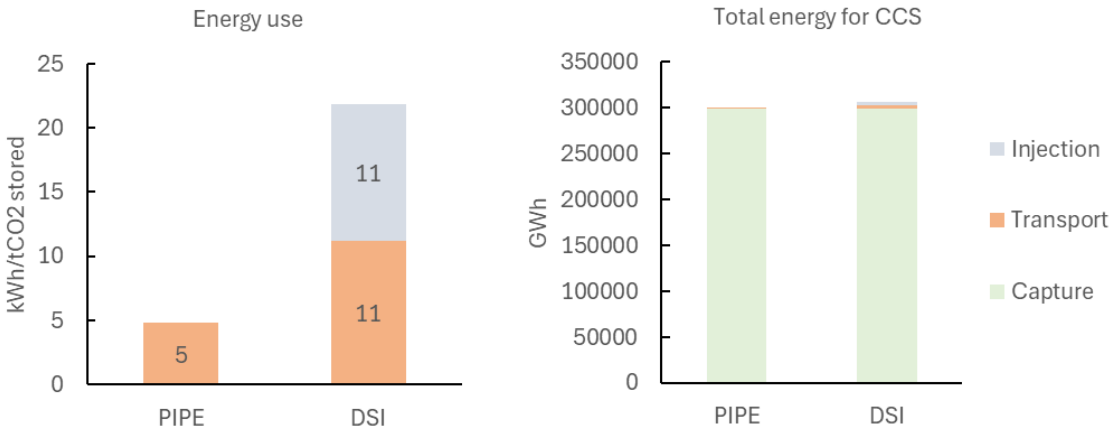


Figure 50. Atlantic Coast – Portugal. Left: transport and injection energy use per tonne of CO_2 stored. Right: total energy demand across the full scenario duration.

7.2.5 Transport and storage additional CO_2 emissions

Table 46 quantifies the additional CO_2 released during transport and injection under each configuration. PIPE introduces the smaller penalty, contributing 2.9 MtCO_2 of extra emissions and resulting in a net abatement of 226.8 MtCO_2, whereas DSI adds 4.0 MtCO_2 along its transport and injection chain, with a corresponding net abatement of 225.7 MtCO_2. The origin of this difference lies in the energy demand and the carbon content of the energy carriers used in each route.

PIPE depends almost exclusively on grid electricity for pumping and requires no energy for injection, as the pressure available at the pipeline outlet is sufficient. In this analysis, electricity is assumed to have a very low carbon intensity in Portugal, reflecting the expected decarbonisation of the national grid.

DSI, on the other hand, draws on electricity for liquefaction at the export terminal and maritime diesel both for ship voyages and for re-conditioning the liquefied CO_2 at the offshore injection site. Hence, the transport and injection emissions of DSI are roughly 1.4 times higher than those of PIPE. The resulting difference of 1.1 MtCO_2 has no relevant impact to the effective net abatement about 98.7%

under PIPE (226.8 $MtCO_2$) and 98.3% under DSI (225.7 $MtCO_2$). This indicates that downstream logistics has only a marginal influence on the overall climate performance of the CCS chain.

Table 46. Atlantic Coast – Portugal. Net CCS abatement by scenario, including transport and injection emissions.

	Transport & injection emissions	Net CO_2 Abated	*Unit*
PIPE	2.9	226.8	*$MtCO_2$*
DSI	4.0	225.7	*$MtCO_2$*

7.2.6 Long-term costs evaluation

Capture represents approximately 84–89% of discounted full-chain cost. PIPE has the lowest total cost, at 15,432 €M or 68.2 €/tCO_2 abated, compared with 16,352 €M or 72.5 €/tCO_2 for DSI. The full-chain difference is approximately 6% because capture costs are common to both configurations (Figure 51).

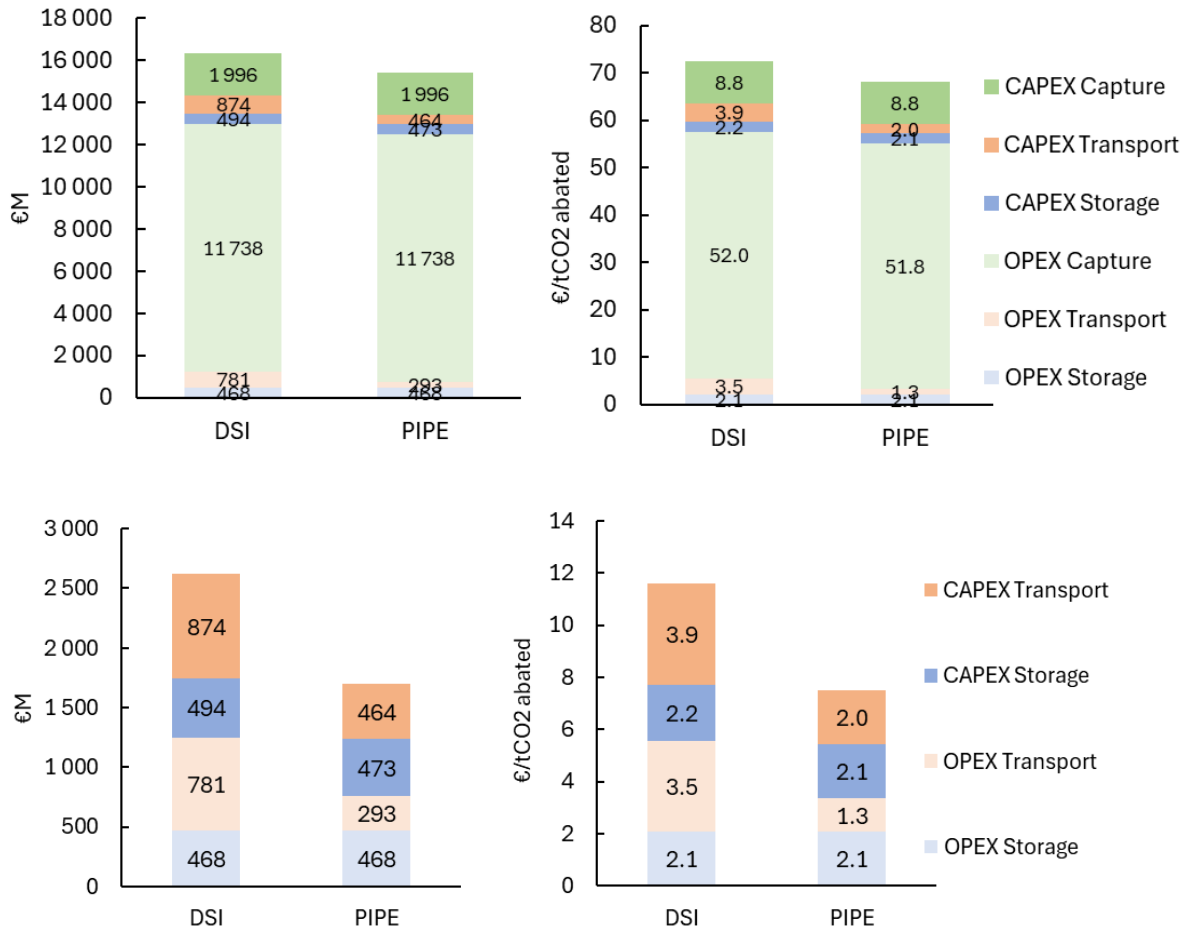


Figure 51. Atlantic Coast – Portugal. Long-term scenarios cost assessment: absolute and specific costs per tonne of CO_2 abated (discounted, in real 2030 €).

Transport and storage comparison

For transport and storage alone, PIPE costs 1,698 €M or 7.5 €/tCO_2 abated, whereas DSI costs 2,617 €M or 11.6 €/tCO_2. The DSI premium is therefore approximately 54% in absolute terms and 55% per

tonne abated. Storage costs are similar; the difference results from higher maritime transport CAPEX and OPEX.

Figure 52 shows a DSI premium of approximately 4.1€/tCO_2 abated, divided between 1.9 €/tCO_2 of CAPEX and 2.2 €/tCO_2 of OPEX. PIPE is therefore the least-cost option. From a planning perspective, this indicates that PIPE remains consistently, and by a considerable margin, more economical. Selecting DSI over PIPE would have to be justified by considerations beyond cost — such as flexibility, scalability, phasing of investment or alignment with broader logistical and infrastructure constraints.

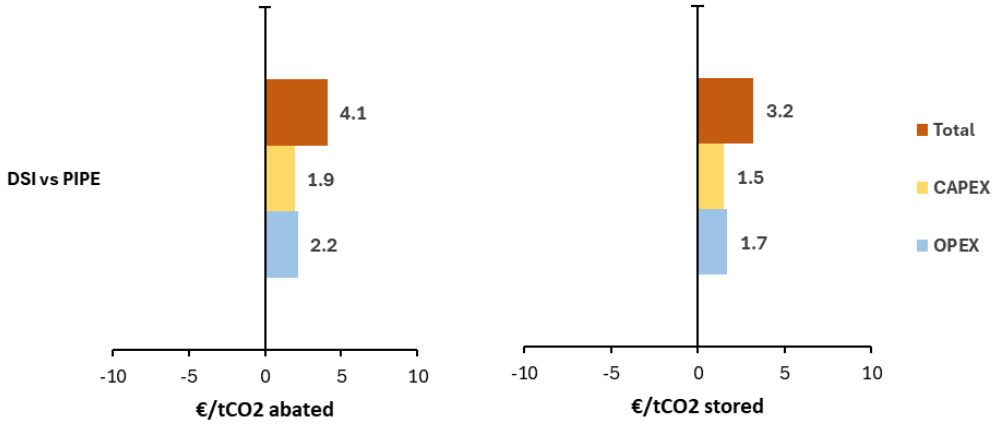


Figure 52. Atlantic Coast – Portugal. Transport and storage costs difference between scenarios.

7.2.7 Atlantic Coast – Portugal conclusions

The Portuguese scenarios store 287.4 $MtCO_2$ over 2035–2065 and deliver net abatements of 226.8 $MtCO_2$ under PIPE and 225.7 $MtCO_2$ under DSI; 135.2 $MtCO_2$ of the stored mass is biogenic. Capture accounts for about 89% of PIPE and 84% of DSI discounted full-chain cost.

Capture is highly concentrated: four facilities (the two Navigator factories in Setúbal and Figueira da Foz, the Petrogal refinery and the CELBI Figueira factory) account for roughly half of the annual captured volume, implying that a small number of emitters underpin the economic viability of the shared transport and storage network.

Economically, capture is overwhelmingly dominant. Capture CAPEX (1,996 €M) and capture OPEX (11,738 €M) together represent close to 89% of the discounted full-chain cost under PIPE and around 84% under DSI.

Transport and storage cost 1,698 €M under PIPE and 2,617 €M under DSI, a DSI premium of about 54% in absolute terms and 55% per tonne abated. DSI's higher cost is driven by both larger transport CAPEX and higher transport OPEX, reflecting the combined burden of ship investment, liquefaction, fuel, and offshore re-pressurisation.

Storage scales from 2 wells injecting 1.9 $MtCO_2$/yr in 2035–2039, up to 12 active wells once the plateau rate of 11.2 $MtCO_2$/yr is reached after 2045. Additionally, 4 backup wells are also required. The staged well deployment defers drilling investment in line with the actual ramp-up of capture. Storage costs do not materially differentiate the cases: discounted storage CAPEX is 473 €M for PIPE and 494 €M for DSI, a difference of about 4.4%, while storage OPEX is 468 €M in both. Storage economics are primarily sensitive to drilling costs and per-well injectivity, and only secondarily to the transport mode selected upstream.

Capture dominates energy consumption (~300,000 GWh over the project lifetime), but when comparing transport and storage energy needs, DSI is about four times more energy-intensive downstream (22 versus 5 kWh/tCO_2 stored) and generates 4.0 rather than 2.9 MtCO_2 of transport-and-injection emissions. Both configurations therefore show an effective net abatement above 98% of the capture-stage reduction.

PIPE is therefore the preferred baseline for large and continuous flows. Nevertheless, DSI should not be completely ruled out: although more expensive, it may suit a phased deployment, since it offers operational flexibility and decouples capture investment from pipeline construction timelines. A hybrid approach at initial stages of development of the transport and storage infrastructure — pipelines serving the main coastal cluster, with ship-based transport handling more distant or later-stage emitters — could combine the cost advantages of PIPE with the flexibility of DSI, and may warrant further investigation in subsequent work.

8 Perspectives for direct injection (DSI) technology

The TEA results show that DSI is generally competitive with conventional ship transport, but its relative performance depends on the regional context and the metric considered. Where PIPE is assessed, it generally provides the lowest cost for large and stable CO_2 volumes, while DSI tends to be less costly than SHIP. In the Baltic and North Sea cases, where only maritime configurations are compared, the ranking is more complex: DSI can reduce upfront infrastructure requirements and absolute transport and storage costs, but its higher operational energy use and associated emissions may increase the cost per tonne of CO_2 effectively abated.

This chapter draws the regional findings together and sets out where direct injection is likely to be the preferred solution, where it is not, and what would have to change for its case to strengthen.

8.1 Where DSI competes

When a pipeline corridor exists and storage volumes are the largest, the results show that pipeline is the lowest cost and lowest emission route to storage. In the Romanian, Ukrainian and Portuguese case studies, the pipeline configuration remains the lowest-cost option for the transport-and-storage segment, with DSI being approximately 28%, 38% and 55% more expensive per tonne of CO_2 abated, respectively. Direct injection does not displace the pipeline on cost in these settings; its value lies in being a complement for emitters that lie off the main pipeline corridor – or when the timing between the capture starts and the necessary transport infrastructure is not synchronized.

The competitive space for DSI appears when sea is the only realistic route to storage. In the Baltic Sea, there is no viable offshore pipeline corridor to the E6 structure, so the comparison is between conventional SHIP and DSI. There, the two options sit within a single cost tier, about 6% apart on transport and storage, and the decision turns on factors other than headline costs. The same pattern holds for the maritime parts of the North Sea network, and for the Ukrainian scenario, where shipping is the default for dispersed coastal sources.

8.2 Structural trade-off: avoided platform versus marine operation costs

The defining advantage for DSI injection is that it removes the need for fixed offshore (or onshore; see Longship case) receiving infrastructure and most of its associated subsea distribution equipment. This translates directly into a clear CAPEX saving – of the order of 50% lower storage CAPEX than conventional shipping in the Baltic case, and several billion euro per gigatonne-scale for the North Sea network. In its effect, DSI converts a large, irreversible upfront investment in fixed infrastructure into recurring operating expenditure carried by the vessel (onboard re-conditioning of the injected CO_2, dynamic positioning and additional marine fuel).

This CAPEX-to-OPEX shift as well as its flexibility for early movers, and the pick-up along routes of dispersed CO_2 capture facilities, is the heart of the DSI proposition. It is attractive wherever upfront capital exposure, phasing risk or uncertainty over final volumes weighs heavily. This is typically very attractive for smaller emitters – that are not connected to larger back-bone CO_2 transport infrastructures (i.e., dispersed while being connected to the sea). Moreover, it is valuable for early movers, where the pipeline infrastructure will be built at a later stage, thus un-locking CO_2 capture projects. The techno-economic analysis shows moreover that DSI is, however, less attractive for very large, stable volumes that justify (even require) dedicated fixed pipeline infrastructure to, and where low operative costs over long lifetime is the priority. Because the two effects roughly offset, DSI and conventional shipping repeatedly end up being only a few percent off each other on the total

transport-and-storage part of the CCS value chain. This conclusion, however, would potentially change significantly by modifying the lifetime of the analysis or the discount rate.

When deciding for an appropriate discount rate when performing techno-economic analyses, rely on analyses based on a series of factors from the central banks interest rate for each country, the inflation in the country or in the EU at large, and/or potentially based on the capital costs for the different companies associated with the value chain (their cost of capital rely on rating). For an investment to become a reality its profitability needs to meet the internal rate of return, and an assessment of future profitability assessment for different future decision alternatives. A discount rate of 5% was chosen.

As the options have markedly different cost profiles, the DSI is the more operating-cost-driven option, while conventional shipping, and especially the PIPE option is the more capital-intensive one. In a stepwise careful development scenario, the DSI could be favoured.

8.3 Indirect emissions and the role of grid carbon intensity

The energy consumption of the alternatives per ton treated coupled to the emissions linked to how this energy is produced, adds an important qualification to the overall analysis. Because direct injection performs reconditioning, i.e., the CO_2 must be heated and pressurized to meet the injection constraints of the reservoir to avoid e.g. freezing around the injector, and the dynamic positioning at the injector, it relies on marine fuel. A platform, however, can rely on power from shore. In the cases where the local grid is carbon-intensive, the distinction is minor and DSI even shows a marginal emission advantage by avoiding an extra handling step (as the Baltic case with coal fired electricity). But where the grid is clean, e.g., the North Sea case, where electricity comes at 30–80gCO_2/kWh against 500–600 gCO_2/kWh for marine diesel – the position reverses: DSI raises chain emissions enough that, despite a small absolute cost saving, it becomes *more* expensive per ton abated. In the cleanest grid, largest volume settings this is the principal argument against DSI in its current form.

8.4 Regional sweet spots

DSI is most favourable when:

- The storage site can only be reached by sea, with no realistic pipeline corridor (e.g., Baltic Sea);
- Volumes are modest, and the emission/capture sites are dispersedly placed, and a dedicated platform would be disproportionate to throughput (see “yellow”, locally based cluster in the North Sea, where DSI is clearly advantageous).
- Deployment is phased or uncertain; e.g., when capture from emitters become a reality before they can be connected to a pipeline infrastructure that is under development, or, avoiding irreversible platform investments that may have optional values;
- Variable or shallow water depths may provide favourable conditions for DSI and should be evaluated in future sensitivity analyses.
- No cost advantage from lower-purity CO_2 streams is assumed in this assessment; any such benefit would require dedicated technical and cost evidence.

DSI is least favourable when:

- A pipeline corridor exists, and the volumes are large and stable (Romania and Portugal along the main corridor with back-bone infrastructure in place).
- The chain is gigatonne-scale and long-haul, and the regional electricity grid is very low-carbon intensive, increasing the relative emissions penalty from the marine fuel and reducing the impact of the captured and stored CO_2 to the overall CO_2 budget (i.e., long-distance North Sea “Green” port clusters).

8.5 What could strengthen the case for DSI?

Several developments, already foreseen in the project, would materially improve the standing of the direct injection DSI option:

- **Decarbonised ship operation.** Onboard CO_2 capture from the vessel's engines, or a switch to low-carbon fuels such as ammonia, would remove the emissions penalty that currently disadvantages DSI in clean-grid regions and close most of the per-tonne-abated gap with conventional shipping.
- **Powering fixed injection from gas turbines.** Conversely, where platforms would otherwise draw on a clean grid, comparing against gas-turbine-powered fixed installations (≈500 gCO_2/kWh) narrows or removes the emissions gap and makes the comparison a more even cost contest.
- **Scheduling and injection optimisation.** Ship size, number of vessels, loading/unloading rates and buffer storage were set manually for this report; the optimisation planned in WP4, with process economics as the objective, is expected to reduce DSI transport cost and refine the per-well batch-injection duty cycles.
- **Technology maturation and demonstration.** Direct injection currently sits at TRL 4–5. Demonstrating the ship-to-subsea connection (riser, hose and control interface) and confirming intermittent-injection behaviour at a pilot — building on the Norwegian and Portuguese pilot tracks — would convert the present cost estimates into bankable figures and de-risk the concept for operators.
- **Regulatory clarity.** The recent clarification of the storage framework in several regions (for example the lifting of the Latvian ban on geological CO_2 storage) reduces a key non-technical barrier and improves the prospects for early maritime-served projects.

8.6 Overall perspective

DSI is best understood as an additional tool in the CCS transport toolbox rather than a universal replacement for pipelines and conventional shipping. Its economics are competitive with conventional shipping wherever maritime transport is unavoidable, and its avoided fixed infrastructure gives it real advantages for smaller, dispersed, phased or early-mover projects. It is not the cheapest option where a pipeline corridor is available, and its current reliance on marine fuel limits its appeal in the very-low-carbon, very-high-volume settings unless ship operation is decarbonised. The technology's most valuable contribution is flexibility — unlocking offshore storage for emitters and regions that would otherwise be unable to justify dedicated infrastructure and accelerating the start of injection while larger networks mature. On that basis, direct ship injection is a credible and strategically useful complement to the European CO_2 transport and storage landscape and warrants the demonstration and optimisation steps identified above.

9 Conclusions

This report conducted a techno-economic analysis of CO_2 transport modes through pipeline (PIPE), conventional ship (SHIP) and direct ship injection (DSI) across four European regions. The aim was to identify the conditions under which DSI would be the best solution. The results confirm that there is no universally preferable configuration that favours DSI transport and storage. The relative performance of each option is controlled by transport distance, available infrastructure, storage location, transported volumes and the carbon intensity of the electricity and fuels used. All comparisons were performed on a consistent basis, using 2030 euros, a 5% discount rate and a 31-year project lifetime for all regions, except for the Baltic case in which 35-years is the project lifetime.

Capture remains the largest contributor to full-chain costs, but the selection of the transport and storage configuration has an important impact on CAPEX, operating costs, energy consumption and net CO_2 abatement.

The Baltic Sea scenario transports and stores 351.8 $MtCO_2$. SHIP has the lowest transport and storage cost, at 6,157 €M, or 22.6 €/tCO_2 abated, compared with 6,532 €M, or 24.0 €/tCO_2, for DSI. The difference between the two configurations is approximately 6%. However, DSI reduces undiscounted storage CAPEX by approximately 47%, from 851.2 €M to 451.2 €M, and slightly increases net abatement from 272.1 to 272.5 $MtCO_2$. SHIP is therefore the lowest-cost option, while DSI may be advantageous where storage development is phased or future CO_2 volumes remain uncertain.

In Black Sea–Romania, 80.4 $MtCO_2$ is transported and stored. PIPE presents the lowest transport and storage cost, at 29.1 €/tCO_2 abated, compared with 37.2 €/tCO_2 for DSI and 39.2 €/tCO_2 for SHIP. DSI and SHIP are approximately 28% and 35% more expensive than PIPE, respectively. PIPE also presents the lowest chain emissions and the lowest non-capture energy consumption: approximately 27 kWh/tCO_2 stored, compared with approximately 49 kWh/tCO_2 for the ship-based configurations. PIPE is therefore the preferred configuration where the expected CO_2 volumes are sufficient to justify the initial investment.

The Black Sea–Ukraine scenario captures and stores 132.1 $MtCO_2$. Transport and storage costs are 18.1 €/tCO_2 abated for PIPE, 25.8 €/tCO_2 for DSI and 28.9 €/tCO_2 for SHIP. DSI is 3.1 €/tCO_2 less expensive than SHIP but 7.6 €/tCO_2 more expensive than PIPE. In terms of total full-chain cost, DSI and SHIP are approximately 7.8% and 10.7% more expensive than PIPE. As in Romania, PIPE is the preferred configuration for large and continuous CO_2 flows, while DSI can provide an alternative where pipeline development is not feasible or must be implemented progressively.

The North Sea scenario stores 2.026 $GtCO_2$. DSI reduces absolute transport and storage costs by 3.7%, from 60.054 €B to 57.840 €B and reduces the cost per tonne stored from 29.64 € to 28.55 €. However, transport and injection emissions increase from 24.6 $MtCO_2$ for SHIP to 69.7 $MtCO_2$ for DSI. Consequently, DSI remains slightly less expensive for transport and storage per tonne abated, at 36.42 €/tCO_2 compared with 36.77 €/tCO_2 for SHIP but becomes more expensive on a full-chain basis: 101.9 €/tCO_2 abated compared with 100.5 €/tCO_2. The North Sea case shows that cost per tonne stored is not sufficient to select the preferred configuration. Chain emissions and cost per tonne effectively abated must also be considered.

In Atlantic Coast–Portugal, 287.4 $MtCO_2$ is transported and stored. PIPE transport and storage costs amount to 1,698 €M, or 7.5 €/tCO_2 abated, compared with 2,617 €M, or 11.6 €/tCO_2, for DSI. DSI is therefore approximately 54% more expensive in absolute terms and 55% more expensive per tonne abated. PIPE is the preferred configuration for the main group of emitters considered in the scenario. DSI may nevertheless be relevant during the initial development of the storage site or before the main pipeline network becomes available.

Overall, PIPE presents the lowest cost where large and stable CO_2 volumes justify dedicated infrastructure. Where maritime transport is required, DSI and SHIP generally present similar full-chain costs but different cost structures. DSI reduces investment in fixed offshore infrastructure but increases operating costs and, where low-carbon electricity is available, may also increase chain emissions. DSI should therefore be considered as a complementary transport and injection option, particularly for dispersed sources, phased developments and early projects that cannot yet be connected to a pipeline network. Further demonstration of ship-to-subsea transfer, intermittent injection and offshore operation is required before its application at commercial scale.

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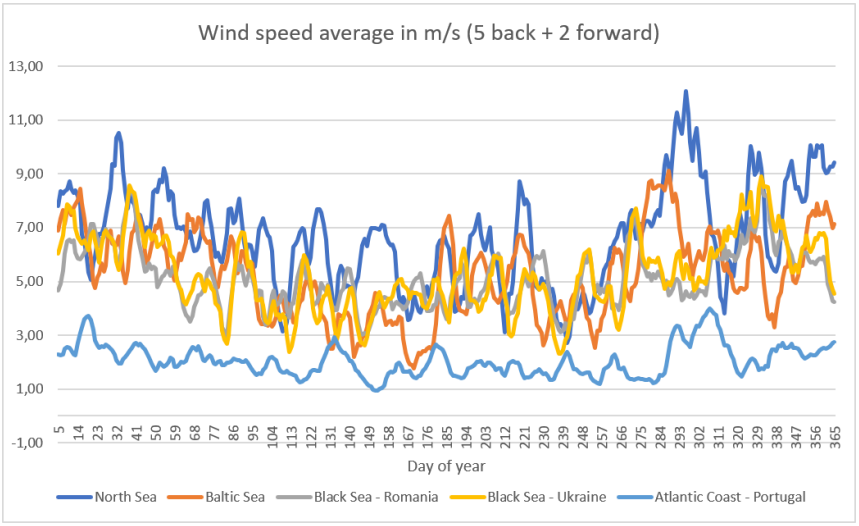
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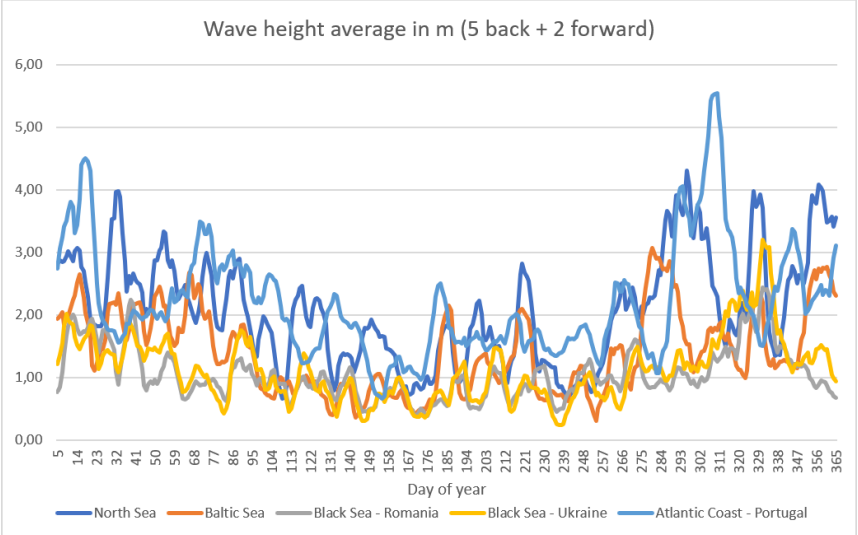
Annex A

Dynamic Positioning system curves and calculations

A.1. Average wind speeds in a year of all the selected locations



A.2. Average wave height in a year of all the selected locations



A.3. Derived average DP power calculation equation for each region

$$DP_{avg}[kW] = a(CargoCapacity^{b})$$

	Equation Parameters	
Region	**a**	**b**
North Sea	2.70704	0.59325
Baltic Sea	1.80531	0.54537
Black Sea – Romania	1.29891	0.56304
Black Sea – Ukraine	1.39228	0.56408
Atlantic Coast – Portugal	11.20584	0.29772

Annex B

Portuguese carbon emissions forecasting overall methodology

Historic CO_2 emissions for each facility in the Portuguese scenario are sourced from EU ETS database except for the Waste to Energy facilities and for some Pulp and Paper facilities, because as of the writing of this report that sector is not covered under EU ETS system. Additionally, EU ETS only covers fossil-based emissions and exempts biogenic source of emissions in the database. To get the total emissions, APA data is used that gives total emissions (fossil + non-fossil). In addition, company's sustainability reports (whenever available) are used to provide any additional details.

The methodology to forecast the emissions in Portuguese scenario follows a mixed multi-dimensional approach. It is dynamic and depends on the industry under consideration, although the basic methodology is as shown in the Figure A4. Although a detailed model with specific assumptions, formulas and calculations are done for each sector, the overall methodological framework for each sector is divided into three distinct processes. Ultimately, these three processes are integrated to obtain the total emissions. These processes are as follows:

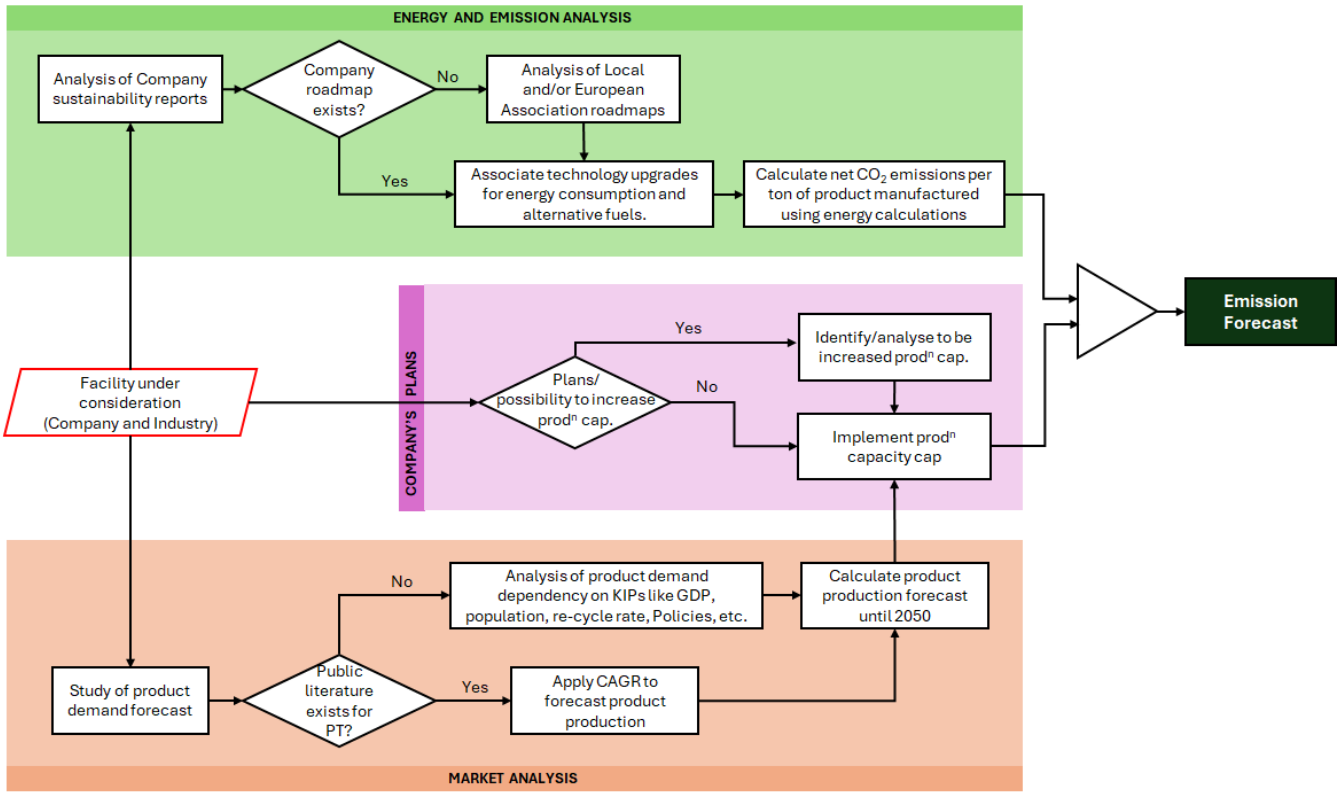


Figure A4. Carbon emission basic methodology approach followed in this study.

B.1. Energy and emissions analysis

This process analyses the technologies and their adoptions in the coming future. It has multiple steps to follow, firstly it considers the existing roadmap of each company/industry. These roadmaps give a probable timeline and possibility of adoption of type of technology and other measures to achieve net-zero carbon emissions. Each company and industry has its own ways of achieving these targets and

therefore, impact on emissions is different for each company/industry under consideration. These technologies and other measures (like electrification, change in combustion technology, recycling, etc.) directly impacts the energy factor (GJ/$t_{product}$).

Another aspect is the adoption of non-fossil fuels in their energy mix. This aspect is driven by company's roadmap, association targets and EU & local policies. The analysis considers the adaptation of non-fossil fuels and divides energy factor into two: biogenic and non-biogenic emissions. All biogenic CO_2 emissions are assumed to be carbon neutral, under the assumption that the biomass feedstocks comply with the sustainability and greenhouse-gas (GHG) saving criteria established under the Renewable Energy Directive (EU) 2018/2001 (RED II) and are accounted for in accordance with the Land Use, Land-Use Change and Forestry (LULUCF) Regulation (EU) 2018/841.

B.2. Market Analysis

Apart from technological advancements and other measures for emission reductions, market forces also affect the amount of emissions for a specific industry. Projected demand is directly proportional to the volume of production in future, and eventually the total CO_2 emissions. Company, associations and literature is reviewed to obtain the CAGR for each type of products and for the future timeline. This gives the change in demand and hence the volume of production from each facility. It is assumed that the increase or decrease in forecasted demand is divided in the same proportion amongst the production facilities as the average historic production proportion of the facility.

In some cases, where CAGR is available, a dependence study is done. This analyses the historic production correlation with the key KPIs like GDP, Population, etc. and finds the best equation and curve to estimate the forecast.

B.3. Company's Plans

Total emissions from a facility are constrained by its production capacity and output levels. Given the energy intensity and emissions intensity, each unit of product corresponds to a defined level of emissions. This step evaluates the company's plans, if any, to expand production capacity and incorporates these changes into the analysis for the years in which they are expected to be implemented.

Together with the volume of production (in tons; limited by the production capacity of the individual facility, $P_{i,c,f,max}$) and available energy factor (GJ/$t_{product}$), the total emission from each facility is calculated. Equation (1) summarizes this approach to calculate the CO_2 from the selected industry where "*i*" refers to selected industry, "*c*" represents the selected company(s), "*f*" is all the facilities of those companies, "*E*" is the energy factor in GJ/t or GJ/MWh (for energy producers), "*P*" is the volume of production in ton or MWh (for energy producers) and "*e*" is the emission factor in tCO_2/GJ.

$$Total\ Industry\ Emission_i(t) = \sum_{i=1}^{N} \sum_{c=1}^{n_c} \sum_{f=1}^{n_f} E_{i,c,f}(t)\ P_{i,c,f}(t)\ e_{i,c,f}(t), \qquad P_{i,c,f} \in [0,\ P_{i,c,f,max}] \qquad (1)$$