Viet Nam Technology Catalogue for Energy transport

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Input for energy
system modelling
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VIET NAM
TECHNOLOGY CATALOGUE
FOR ENERGY TRANSPORT

Input for energy system modelling

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FOREWORD

Today, innovation in energy technologies is advancing at a rapid pace. As energy systems evolve, so does the need to assess the costs, technical performance, and environmental impacts of emerging technologies, which are highly context dependent. Reliable and transparent information on these characteristics is essential for sound long-term energy planning.

This Technology Catalogue provides a review-based technical foundation for a wide range of energy transport technologies in the Vietnamese context. It aims to support evidence-based planning and analysis of Viet Nam's future energy system. By presenting consistent data and assumptions on costs and performance, the catalogue contributes to strengthening energy system planning as a central tool for unlocking the potential of new renewable-based technologies.

Through a multi-stakeholder involvement in the data and information collection process, all quantitative figures incorporated to this Technology Catalogue were thoroughly reviewed and scrutinized by a broad range of energy sector stakeholders in Vietnam, including Electricity Authority of Viet Nam (EAV), agencies under the Ministry of Industry and Trade (MOIT), Viet Nam Electricity (EVN), independent power producers, local and international experts, other development partners organizations, as well as energy branch associations and universities. This stakeholder engagement constitutes an essential element in the development process, to ensure that the Technology Catalogue is highly context specific, well anchored and legitimized by all relevant energy sector stakeholders.

The aim of this Technology Catalogue is therefore to serve as a key foundation for long-term energy planning and modelling in Viet Nam, thus supporting government institutions, private energy companies, think tanks and others through a common and broadly recognized set of data for current and future electricity producing technologies in Viet Nam.

This Vietnamese Technology Catalogue builds on the approach of the Danish Technology Catalogues, which for many years have been developed by the Danish Energy Agency and Energinet through an open stakeholder process, serving as a key foundation for Denmark's long-term energy system planning.

Context

This publication is developed under the Danish-Vietnamese Energy Partnership Programme. The first Viet Nam Technology Catalogue for power generation and storage technologies was published in 2019, and subsequently updated in 2021 and 2023. This publication introduces a new Technology Catalogue focusing on energy transport technologies, covering both electricity transmission and the transport of fuels in different forms.

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CONTENT

ABBREVIATIONS

Amb.	Ambient condition (P=1.025 bar, T€[-50:50] °C
CC	Carbon Capture
CH2	Compressed hydrogen
CNG	Compressed natural gas
CNO	Number of carbon atoms in a chemical molecule
CP	Cathodic protection
DME	Dimethyl-Ether
DN	Nominal diameter
dP/dL	Pressure drop per length (bar/km)
E	Energy
EIGA	European industrial gases association AISBL
ESD	Emergency shutdown
EVN	Electricity of Vietnam
EVNNPT	National Power Transmission Corporation
GT	Gross Tonnage
H_2	Hydrogen
H2NG	Fuel group: include H_2 and NG
HB	Material hardness measured by "Hardness Brinell" method
HC	Hydrocarbons, i.e. molecules that consist of only C and H (C_nH_m)
HHV	Higher heating value
HRC	Material hardness measured by "Hardness Rockwell C" method
HVAC	High voltage alternative current
HVDC	High voltage direct current
L20	Fuel group: include DME, NH_3 and LPG (and ethane)
LDME	Liquefied dimethyl-ether
LH2	Liquefied hydrogen
LHC	Fuel group: All fuels that are liquid at P=1.025 bar and T=50°C
LNG	Liquefied natural gas
LNH3	Liquefied ammonia
LPG	Liquefied petroleum gas
M	Mass
M/R	Metering and regulation station
MTPD	Metric ton per day
NG	Natural gas
NH_3	Ammonia
NSMO	High voltage alternative current

O&M	Operation and maintenance
P	Pressure
Pd	Design pressure
PDP	Power development plan
PG	Petroleum gas
Pin	Inlet/suction pressure
Pmax	Max operation pressure
Pmin	Min operating pressure
Pout	Outlet/discharge pressure
PSA	Pressure swing adsorption unit (separate components by selective absorption at high pressure and desorption/regeneration at low pressure)
PSV	Pressure safety valve (protect against overpressure)
Q	Energy flow, MW
R&D	Research and develop
RE	Renewable power
SCC	Stress corrosion cracking
SMR	Steam Methane Reforming
T	Temperature
Td	Design temperature
US	United States
VLGC	Very large gas carriers/ships
W	World

INTRODUCTION

This Technology Catalogue consists of four main chapters describing energy transport technologies in the Vietnamese context, covering electricity, gas and liquid fuels, coal and solid fuels, and nuclear fuel transport. Within each chapter, a number of specific technologies are assessed, as summarized in Table 1 of this introduction. This introduction outlines the scope, methodological principles and structure of this Technology Catalogue. A detailed description of the approach and methodological principles is provided in the methodological Appendix of this document.

Scope and Purpose

Reliable information on the cost, performance and environmental characteristics of energy technologies is essential for long-term energy planning. As energy technologies continue to evolve, their technical and economic performance varies across countries depending on local conditions, regulatory frameworks and market maturity. Consistent and transparent information is therefore needed to assess how energy transport technologies can support the development of Viet Nam's evolving energy system. The purpose of this Technology Catalogue is to provide a harmonized basis for assessing technologies and supporting long-term energy planning.

This catalogue compiles technical and economic information for a range of energy transport technologies based on Vietnamese experience where available, and international evidence where necessary. By presenting harmonized assumptions for technology costs and performance parameters, the catalogue enables consistent comparisons across technologies and provides a common analytical foundation for planning and modelling. With this scope in mind, the catalogue is not intended to provide an exhaustive collection of specifications for all available technology variants. Rather, it presents selected and representative technologies to enable comparison between technologies with similar functions in the energy system.

This catalogue reflects that different energy transport technologies serve different functions across the energy system and across different energy carriers. It therefore covers technologies for the transport of electricity, gas and liquid fuels, coal and solid fuels, and nuclear fuel, including both transport infrastructure and associated stations or transport modes where relevant. The technologies are compared not only on cost and performance, but also on their typical technical characteristics, losses, scale and system function. The hierarchy of technologies and the categorization applied in the catalogue are presented in the methodological Appendix of this document.

System boundaries and technological maturities

The technologies described in this catalogue cover mature and emerging technologies. As a result, the cost and performance of some technologies are associated with a higher level of uncertainty than others. To reflect these differences, uncertainty ranges are provided for key parameters such as investment costs and energy losses. In addition, the technologies are grouped into four categories of technological development. This grouping is described in the section on "Prediction of performance and cost" in the Appendix and reflects technological progress, future development perspectives and the uncertainty related to projected cost and performance data. As far as possible, technical parameters and investment costs are informed by Vietnamese project experience. At the same time, for technologies not yet widely deployed or documented in Viet Nam, such as nuclear energy, figures might rely on authoritative international sources or be limited to qualitative descriptions only.

For all technologies, the presented cost and performance data refer to the transport asset and the associated infrastructure required to connect it to the relevant energy system. This includes the main transport component, such as transmission lines, cables, pipelines, ships, conveyor systems, rail transport or trucks, as well as the stations and auxiliary components required to transform, regulate or support the transport of the energy carrier. For electricity transport technologies, this includes substations, transformers and compensation equipment where relevant. For gas and liquid fuel transport, this includes pressure regulation, compression or loading infrastructure. For coal and solid fuel transport, it includes the relevant transport mode and associated handling requirements.

Methodological principles and cost projections

To ensure comparability across technologies, all economic and technical data are reported using a common set of methodological assumptions. Economic data are expressed in constant 2025 U.S. dollars, excluding taxes such as value-added tax (VAT).

For most technologies, the catalogue provides cost and performance estimates for the relevant years between 2025 and 2050. The information in the quantitative tables refers to the development status of the technology at the point of final investment decision in the given year. Future cost and performance developments are estimated based on technology-specific assumptions, including engineering-based assessments, learning effects and scenario-based assumptions regarding future deployment where relevant. The methodology reflects the different maturity levels and data availability of the technologies considered, and projections are informed by relevant Vietnamese and international sources.

Structure of the technology sheets

Technologies are described in a standardized manner consisting of two main elements.

- **The qualitative descriptions** provide a concise explanation of the considered technology, including its operating principles, main components, key inputs and outputs, operational characteristics, advantages and disadvantages relative to alternatives, environmental characteristics including space requirements where relevant, and research and development perspectives. Examples of current projects are included, with Vietnamese examples provided for technologies already applied in Viet Nam and international examples for technologies that are new to the Vietnamese market.
- **The quantitative sections** focus on the technical and economic parameters most relevant for long-term planning models. Tables contain data for the relevant years between 2025 and 2050 and include, among other, investment and operation and maintenance costs, technical lifetimes, construction times, transport losses and other technology-specific performance parameters. For some technology groups, different data sheets are provided for different transport levels, station types or sub-technology variants. To account for the inherent uncertainty related to projected data, tables also include uncertainty spans, evaluated on a case-by-case basis.

Each energy type is introduced through a general qualitative description. For electricity, gas, liquid and coal transport, quantitative sections and data tables are included for selected technologies and, in some cases, differentiated by transport level, station type, or scale. For nuclear fuel transport, the current chapter includes qualitative descriptions only, reflecting limited data availability and the absence of nuclear power generation in Viet Nam.

Table 1: Overview of considered technologies

Energy transport technologies
• Electricity, overhead lines, AC • Electricity, overhead lines, DC • Electricity, underground and sea cables, AC • Electricity, underground and sea cables, DC • Electricity, substations, AC and DC, onshore and offshore • Electricity, transformers • Electricity, compensation • H_2, 70 bar, pipeline • H_2, 140 bar, pipeline • NH_3, pipeline • NG, pipeline • LH2, L20, LHC, ship transport • LNG, ship transport • Coal, ship transport • Coal, train transport • Coal, truck transport • Coal, conveyor transport • Nuclear fuel transport

1. TRANSMISSION OF ELECTRICITY

1.1. Alternating current transmission

Brief technology description

Overview

In a power system, the grid plays the role of connecting, transmitting, and distributing electricity from power plants to consumers. The grid consists of networks of transmission lines linking power sources and loads, along with equipment to ensure the quality of electricity supply (voltage, frequency, etc.) to end-users in compliance with regulations.

Vietnam's power system is currently operating at extra-high voltage levels of 500 kV, high voltage levels of 220 kV–110 kV, medium voltage levels from 35 kV down to 6 kV, and low voltage levels [1]. Currently, Vietnam's transmission grid operates at 220 kV and 500 kV alternating current (AC) voltage levels. The 500 kV network is considered the backbone of the national power system, running from North to South with a total length of over 1,500 km. The 220 kV network serves as the backbone of each regional power system, ensuring safe and continuous electricity supply to regional and local grids. The 500 kV and 220 kV transmission networks are primarily managed and operated by the National Power Transmission Corporation (EVNNPT). The transmission grid under EVNNPT's management consists of critical backbone infrastructure, including the 500 kV backbone network and inter-regional and inter-area transmission lines. In recent years, several 220 kV and 500 kV transmission projects have also been directly invested in and constructed by private entities to facilitate the grid connection of renewable energy sources in order to meet the deadlines for benefiting from the Government's incentive policies [2]. Vietnam's transmission grid is designed in a meshed (ring) configuration, complying with operational safety and reliability standards: N-1 criteria for critical load areas and N-2 criteria for particularly important load centres.

The distribution of power generation and load in Vietnam is characterized by imbalance. Locations favourable for power generation are often far from load centres. In the past, hydropower plants were mainly developed in the mountainous Northwest, coal-fired power plants in the Northeast, Central Coastal regions, and the Mekong Delta. In recent years, with the energy transition orientation, Vietnam has focused on developing renewable energy sources such as wind and solar power. Regions with potential for wind and solar power include the Central Highlands, South Central Coast, and Mekong Delta. Meanwhile, the two main load centres are located in Hanoi (North) and Ho Chi Minh City (South), where power generation potential is limited. Therefore, the 500 kV national transmission grid is one of the key solutions to ensure electricity supply to major load centres. Inter-regional transmission volume in Vietnam has increased significantly in recent years [3].

Currently, Vietnam's grid is interconnected with those of neighbouring countries, including China (in the North), Laos (in the North Central, Central, and Central Highlands), and Cambodia (in the South). Vietnam imports electricity from China and Laos and exports electricity to Cambodia.

Reliability

Industrialised countries seek to obtain a high level of power system reliability because the economic losses from power outages are substantial.

Operating reserves are not only related to unexpected outages but also to deviations in forecasts of electricity demand and wind and solar generation. Operating reserves include spinning reserves, regulating reserves, and flexibility reserves for solar and wind power, which can be determined on an hourly basis and may depend on factors such as forecasted wind generation, solar generation, and demand in each hour. Operating reserves for contingency events are defined as the sum of the outage of the largest generating unit (N-1) and additional contingencies (N-2), for example the loss of a transmission line or another large generating unit. The table below refers to proposed operating reserve requirements for high-RES power systems as studied by NREL [4].

Table 2: Operating Reserve Requirements for High-RES Power Systems (NREL Study)

Type	Requirement for load	Requirement for wind power	Requirement for solar power	Capacity	Response time
Spinning reserve	3% load				10 minutes
Regulating reserve	1% load	0.5% capacity of wind power	0.3% capacity of solar power		5 minutes
Flexibility reserve		10% capacity of wind power	4% capacity of solar power		60 minutes
Reserve for contingencies N-1, N-2				Exact capacity	60 minutes

For the Vietnamese power system, there are currently no new regulations on reserve types for a power system with high renewable energy penetration. According to the 2022 study on determining ancillary service requirements for the power system, NSMO proposed operating reserves for renewable energy variability (solar and wind) at around 5% of solar and wind capacity in each region.

Proposing reserve requirements in modelling to ensure system reliability as follows:

- Spinning reserve: 3% of load capacity;

- Regulating reserve: 1% of load capacity and 0.5% of wind and solar capacity;

- Flexible reserve: 5% of solar capacity and 5% of wind capacity;

- Contingency reserve (N-1): The larger of either the largest generating unit capacity in each region or one interregional transmission line to that region;

- Long-term hydrometeorological variability reserve for years with low water inflows, weak wind, or low solar radiation: This is referred to as strategic reserve, which the model always keeps as a fixed amount of reserve without dispatching it.

Main components

HVAC line

Power is usually transmitted through overhead power lines. Underground power transmission has a significantly higher installation cost and greater operational limitations but lower fault frequency. However, cable faults need longer repair times. Underground transmission is more common in urban areas or environmentally sensitive locations. In densely populated areas, cables often provide the only technically viable solution.

In Vietnam, since the cost of constructing cables is much higher than that of overhead lines, cables are typically used only in areas with difficult construction conditions (such as land clearance challenges like urban zones, offshore areas or power supply to islands).

Choice of conductors is based on considerations such as cost, transmission losses and other desirable characteristics of the metal like tensile strength. Copper, with lower resistivity than aluminium, was once the conductor of choice for most power systems. However, aluminum has a lower cost for the same current carrying capacity and is now often the conductor of choice. Overhead line conductors may be reinforced with steel or aluminium alloys [5].

Conductors may be placed overhead or underground. Overhead conductors are usually air insulated and supported on porcelain, glass or polymer insulators. Cables used for underground transmission are insulated with cross-linked polyethylene or other flexible insulation. Conductors are often stranded to make them more flexible and therefore easier to install.

Conductors are typically rated for the maximum current that they can carry at a given temperature rise over ambient conditions. As current flow increases through a conductor it heats up. For insulated conductors, the rating is determined by the insulation, routing of cable phases, configuration of metal shields and installation conditions, including soil conditions and installation depth.

For overhead line conductors, the rating may be determined by the max. allowable sag or the conductor's max. permittable temperature. For long overhead line connections (depending on compensation) there are also other problems that can limit the rating, including restrictions related to voltage drop and phase angle stability.

In Vietnam, overhead lines typically use Aluminum Conductor Steel Reinforced (ACSR) cables. An ACSR conductor consists of a steel core surrounded by layers of twisted aluminum strands, where the steel core provides tensile strength and mechanical durability, while the aluminum strands serve as the electrical conductor. Aluminum is an excellent conductor at a lower cost compared to copper, but it has lower mechanical strength. A conductor made entirely of aluminum cannot be installed over long spans due to its high sag under load at elevated temperatures. This drawback is overcome by the steel core, which enhances the conductor's tensile strength and mechanical resilience. At the 500 kV level, commonly used conductors include ACSR 4×330, ACSR 4×400, ACSR 4×500, and ACSR 4×600, arranged in a quad-bundle configuration to enhance transmission capacity and reduce corona losses. For the 220 kV grid, conductors may be single or bundled, with typical cross-sections such as ACSR 500, ACSR 2×330, ACSR 2×400, and ACSR 3×400, selected according to load requirements and environmental conditions.

For power cables, XLPE (Cross-Linked Polyethylene) cables are commonly used. Essentially, XLPE is produced from ordinary polyethylene (PE) but undergoes a “cross-linking” process, either chemically or physically, which transforms the linear PE molecular chains into a robust three-dimensional (3D) network structure. XLPE cables outperform PVC cables due to their high thermal resistance (continuous operation at 90–120°C and short-circuit withstand up to 250°C), excellent insulation for voltages up to 500 kV, strong mechanical and chemical durability, moisture resistance, and long lifespan of 40–50 years. Moreover, LSZH XLPE cables are safer and much more environmentally friendly compared to PVC. In urban areas, where overhead lines are difficult to deploy, high-voltage underground cables are applied, with typical cross-sections of 1200 mm^2, 1600 mm^2, and 2000 mm^2, meeting high transmission demand while preserving urban aesthetics.

One of the rapidly emerging conductor technologies is High-Temperature Low-Sag (HTLS) conductors, which have the same diameter as Aluminum Conductor Steel Reinforced (ACSR) conductors and can operate at temperatures up to 250°C. In addition, HTLS conductors exhibit less thermal expansion than ACSR conductors. One technique to increase the thermal rating of an existing line is to replace ACSR conductors with HTLS conductors while maintaining the same transmission right-of-way (RoW). Installing and operating HTLS conductors does not require significant modifications to the foundations or existing structures.

High-Temperature Superconducting (HTS) cables represent a revolutionary advancement in power transmission. HTS cables are extremely efficient and can transmit larger amounts of power over longer distances because they conduct electricity with zero resistance, unlike conventional copper or aluminum conductors. Due to their lighter and more compact design compared to conventional alternatives, they are often used in urban environments where space is limited.

In general, HTS and advanced high-temperature conductors are classified into four types: Aluminum Conductor Composite Core (ACCC), Aluminum Conductor Steel Supported (ACSS), Super Thermal Aluminum Reinforced (STACIR), and Gap-Type High-Temperature Aluminum Alloy ACSR conductors.

- ACCC conductors consist of a carbon composite core and trapezoidal annealed aluminum strands. They can double the transmission capacity, exhibit lower sag at high operating temperatures, reduce carbon emissions, and decrease transmission line losses by 20–30%.
- ACSS conductors are made from annealed 1350 aluminum strands with a Galfan-coated steel core (5% zinc and rare-earth aluminum alloy) providing high tensile strength. These conductors can operate at temperatures up to 250°C, have low losses due to the annealed aluminum, and are easy to install.

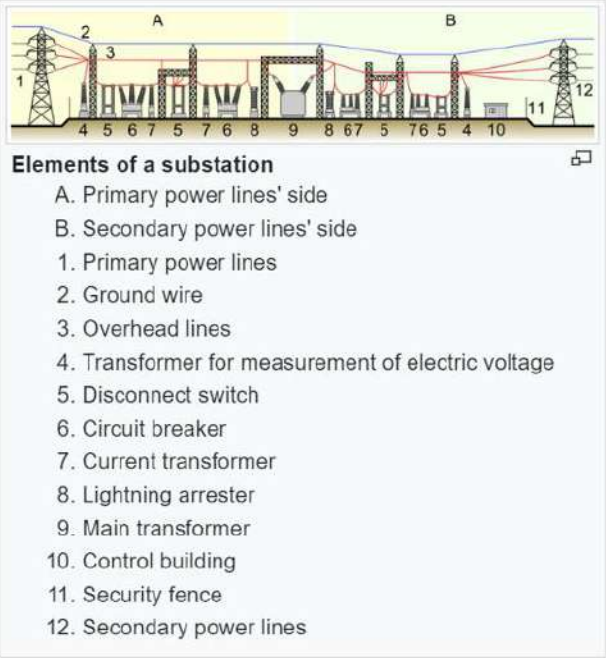
- STACIR conductors are made from zirconium-aluminum alloy rods, providing up to 100% higher transmission capacity but with higher losses. They feature a strong Invar steel core and concentric layers of high-temperature aluminum strands forming the outer layer.
- Gap-type high-temperature aluminum alloy ACSR conductors (or gap-filled conductors) have the space between the steel core and the inner aluminum layer filled with heat-resistant grease to reduce friction and prevent corrosion.

Because of small space requirements super conducting cables may in the future find wider application in (transmission) congested urban areas where they can provide high power transport capacity. Here they can be routed underground through existing gas, oil, water or electric corridors thus avoiding need of obtaining additional and costly right of way.

The losses of the superconducting cables are mostly due to the energy required to keep low nitrogen temperatures and its circulation. The technology requires special cable joints and specific cable terminations for extreme temperature differences and permanent cooling for keeping very low temperatures.

HVAC substation and compensation station

Transmission substations are found where electricity enters the transmission network (often near a major power source), or where it leaves the transmission network for distribution to homes and businesses. Because the output from power generators – such as biomass plants or wind power plants – have different voltage levels than the voltage level of the grid, the output must be converted by a transformer to a level that suits the transmission system.



Elements of a substation

A. Primary power lines' side
B. Secondary power lines' side
1. Primary power lines
2. Ground wire
3. Overhead lines
4. Transformer for measurement of electric voltage
5. Disconnect switch
6. Circuit breaker
7. Current transformer
8. Lightning arrester
9. Main transformer
10. Control building
11. Security fence
12. Secondary power lines

Figure 1: Elements of a substation, example [6]

Substations can be AIS or GIS stations. AIS (Air insulated substations) uses air as the insulating medium (open air stations), while GIS (Gas insulated substations) uses specialized insulating gases, e.g., SF6. AIS tends to have larger physical dimensions and requires more spacing between components, whereas GIS offers compact designs with reduced maintenance requirements. Vietnam has issued and implemented various standards and regulations to control the quality and use of SF_6 gas in high-voltage electrical equipment, ensuring safety and minimizing environmental impacts. Specifically, Circular 02/2025/TT-BCT of the Ministry of Industry and Trade stipulates the analysis of SF_6 gas after initial filling or during operation, including checks on purity, moisture, and the content of decomposition products such as SO_2. In cases where manufacturers do not provide specifications, assessments must refer to international standards such as IEC 60376 (new SF_6 gas), IEC 60480 (used SF_6 gas), and IEC 61634 (handling procedures for SF_6 gas in electrical equipment). In addition, the national standard TCVN 11845-1:2017 (IEC 61869-1:2007) also confirms the requirement to comply with these international standards in the design and operation of electrical measuring equipment. The consistent application of these standards demonstrates Vietnam's efforts to strictly manage SF_6 gas, thereby ensuring power system safety and contributing to sustainable development goals.

A substation typically consists of the following equipment: power transformers (three-phase transformers for the transmission grid), high-voltage switching devices, disconnectors, busbar systems, surge arresters, protective relays, measuring instruments (current transformers, voltage transformers), grounding systems, and power cables (high-voltage, medium-voltage, and low-voltage). Additional electrical equipment to improve power quality, such as series capacitors, shunt capacitors, and shunt reactors, is often installed in the switchyard of substations. Figure below illustrates the layout of a substation with its elements.

HVAC Transformers

An important element is the transformer enabling change in AC voltage and thus allowing operators to interconnect AC networks of different voltage levels to each other. Power transformers must be built to withstand severe electrical stress from fault currents and transients. Their availability and longevity have a major impact on grid reliability and profitability.

Transmission transformers typically have very large capacities, reaching hundreds of MVA (Mega Volt-Amperes), to meet the demand for large-scale power transmission. They are also specially designed to withstand high currents and voltages, protecting the power system against short circuits and overloads. In Vietnam, transformers with capacities of 450 MVA, 600 MVA, and 900 MVA are currently used for 500/220 kV substations, while 250 MVA and 125 MVA transformers are used for 220/110 kV substations. Due to their large capacity, 500/220 kV transformers are often split into three units, corresponding to phases A, B, and C.

To operate in large transmission networks, transmission transformers are designed with complex structures. The main components include the magnetic core, windings, transformer tank, and various auxiliary parts.

Integrating a tap changer with the transformer allows for the regulation of the output voltage by adjusting the number of transformer windings (the transformation ratio). Although the effects on the network depend on the network itself, this nonetheless enables more flexibility to the operator compared to a fixed voltage step up or down ratio.

Key functions of power transformers with tap changers are [7]:

- Voltage step-up and -down: As increasing voltage will reduce the currents required to transmit the same electrical power, step-up transformers are used to minimise transmission line losses. Step-down power transformers are used to bring down transmission voltages to usable voltage level for end-customer connections.
- Slow dynamic regulation to adjust to changing network conditions, supporting the voltage stability of the AC-grid.

Compensation equipment

Compensation equipment is used to control voltage and transfer capacity of the transmission grid. Compensation is in the form of reactive power provided or consumed by means of capacitor banks or reactors, flexible alternating current transmission systems (FACTS), etc.:

- Reactive power[1] can be provided by generators themselves (any generator or demand facility must be able to control reactive power within certain limits to be granted a grid connection), or alternatively provided through capacitors[2]. Hence capacitors are often placed near inductive loads (i.e. if not on-site at the nearest substation) to reduce transport of reactive power on transmission lines. Capacitor banks help to raise the voltage profile and improve the power factor by supplying reactive power and thereby relieving the transmission line of transporting the reactive power to inductive loads (appliances with moving parts as motors, fans, etc.).

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[1] Reactive power is used to generate electromagnetic fields for the operation of inductive loads such as motors, transformers, and transmission lines. Moreover, reactive power also provides the function of regulating voltage levels in transmission lines, ensuring a smooth supply of real power. Real power is that part of the power that can do work.

[2] Capacitors are electronic components that provide energy storage in the form of an electrostatic field. A capacitor provides reactive power and raises the voltage profile.

- Reactors absorb reactive power and reduce the voltage level on the transmission line and are typically used in connection with high voltage underground cables or light loaded overhead lines. When the voltage level is lower due to higher loads, the reactor is disconnected again.
- Static Var Compensator (SVC). An SVC includes both a capacitor and a reactor. The main advantage of SVCs over simple mechanically switched capacitors/reactors is their near-instantaneous response to changes in the system voltage by using power electronics. For this reason, they are often operated at close to their zero-point to maximize the reactive power correction they can rapidly provide when required.
- A static synchronous compensator (STATCOM) is a fast-acting device capable of providing or absorbing reactive power and thereby regulating the voltage at the point of connection to a power grid [7]. The technology is based on SVCs, but a STATCOM offers better dynamic performance than an SVC, in particular a faster response time.

Input

The input for the transmission system is electrical power, but this power can come from various sources. Historically, electrical power was generated at utility scale by thermal power plants, hydropower plants, and nuclear power plants with power levels in the range of a few hundred kW up to about 1000 MW. Thermal power plants and nuclear power plants use fuel (coal, gas, oil, nuclear fuel) as a primary energy source, which is used to heat water into high pressured steam that drives a turbine-generator set producing electricity.

Thermal plants, especially gas power plants, have a high ability to regulate the power output. Also, hydropower has a high ability to quickly ramp up and down power regulation- with reaction time below a second. The water behind the hydropower dams represents an energy storage that can be used to provide balancing services on short notice. Besides, the storage is used to accumulate water from rainy periods and provide balancing power on a seasonal level.

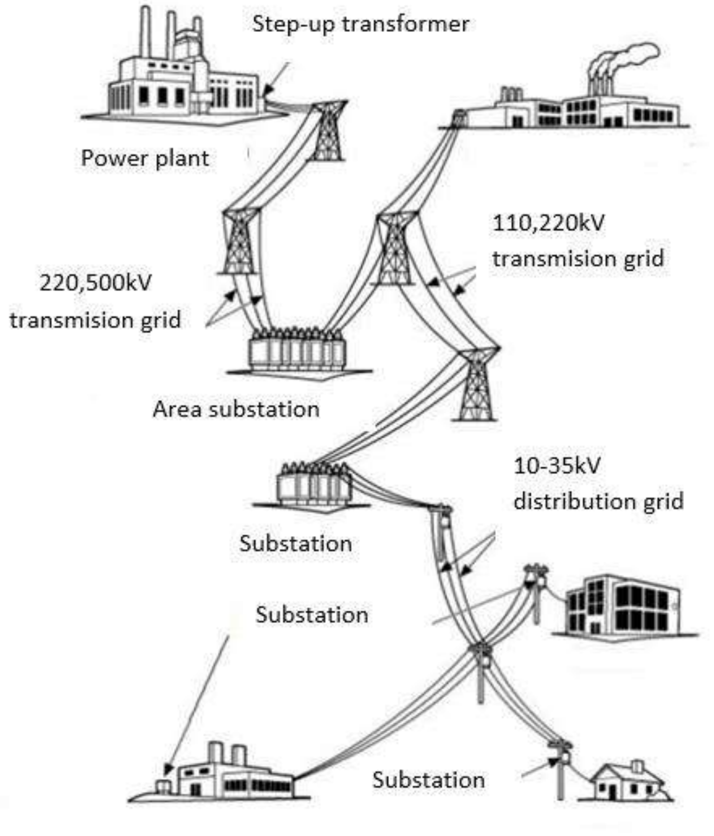

Figure 2: Illustration (example) of major components in Vietnam electric power grid

The turbine-generator sets of thermal, nuclear and hydropower plants have, thanks to the large rotating masses, a significant amount of inertia. In comparison, solar panels and wind turbines do not have effective inertia.

Inertia provides stability to the power system and is an important factor for the dynamic grid stability and security of supply. Large scale power plants are normally connected to the transmission network by a step-up transformer and may be located far from demand centres where the fuel (coal, natural gas, uranium) is located, processed or stored. Generation based on conventional generators are characterised as synchronous generation.

Vietnam's current power sources include coal-fired power, gas-fired power, oil-fired power, hydropower, biomass, wind power, and solar power. Before 2019, Vietnam's power generation mainly consisted of conventional plants such as coal, gas, and hydropower. Since 2019, thanks to the Government's incentive mechanisms for renewable energy, solar and wind power have developed significantly. By 2024, Vietnam's power system had nearly 9 GW of utility-scale solar and nearly 6 GW of wind power.

Vietnam power system has been formulated with the orientation of stronger development of renewable energy sources combined with storage and flexible resources to meet the country's high load growth. Regions with high potential for wind and solar power such as the South-Central Coast, Central Highlands, and Mekong Delta are located relatively far from the main load centres such as Red River Delta and the Southeast region. Therefore, the role of the transmission grid is becoming increasingly important.

Output

The output of the transmission system is electric power which has a vast usage in the society. Electricity demand in Vietnam is divided into 5 sectors: Agriculture, Industry, Commerce, Residences and Others.

Vietnam's electricity consumption structure reflects the characteristics of a developing country. The industrial and construction sector accounts for the largest share of total national electricity consumption, at over 50%, followed by electricity consumption for administration and residential use, accounting for around 35% of total demand. Electricity consumption in other sectors represents only a small portion, about 3–5% of total national electricity consumption.

By region, the North and the South are the two main load centres of the country, together accounting for around 90% of total national commercial electricity consumption.

The growth rate of commercial electricity over the past four years (2021–2024) has averaged about 7.1% per year. The growth rate of the national peak load was about 4.8% per year, significantly lower than in the period 2016–2020 (around 8.6% per year). The main reason was the impact of the COVID-19 pandemic on production activities during 2020–2021.

Energy balance

In an electrical system, electricity consumption needs to be continuously balanced with production. The transmission system operator (TSO) is responsible for this balance in real time and maintains a second-by-second balance between electricity production from producers and demand from consumers, import/export and losses.

In Vietnam, transmission grid electricity losses are around 2.5% [3]. Overall, the transmission loss rate has shown a declining trend over the years, but tends to increase in years when large volumes of electricity are transmitted across regions.

The National System and Market Operator (NSMO) is responsible for operating the power system to ensure supply–demand balance. To achieve this, NSMO prepares annual, monthly, and weekly operation plans. For actual market-based dispatching, NSMO implements scheduling in three stages: the day-ahead market, the intra-day/next-cycle scheduling, and real-time operation.

- Day-ahead market: Based on load forecasts, NSMO allocates capacity for specific power sources that do not participate in the market, typically multi-purpose hydropower and domestic gas-fired power plants. At the same time, market participants submit their bidding offers. NSMO then optimizes system operation costs to determine the dispatch schedule for the following day.

- Intra-day/next-cycle scheduling: During the operating day, NSMO reviews and adjusts the dispatch schedule on a cycle basis or when significant changes occur in demand, generation output, bidding offers from power plants, or grid operating conditions. This ensures feasibility of the plan and maintains system cost optimization.
- Real-time operation: NSMO directly dispatches power, activates reserves and ancillary services to instantly balance supply and demand, and maintains frequency and voltage stability. Deviations from prior schedules are settled through the balancing market. At the same time, NSMO intervenes in the electricity market to ensure system security, including suspending or restoring the market in emergency situations.

In the operation of the power system, the transmission grid plays a particularly important role in balancing supply and demand across regions. When hydropower in the North is affected by unfavourable hydrological conditions leading to reduced output, the system must mobilize additional sources from the North Central and Central regions to supplement capacity and transmit electricity back to the North. Conversely, in areas with high potential for power development, the transmission grid serves to transfer surplus electricity to load centres, thereby enhancing the efficiency of power generation nationwide. Thus, transmission is not only the “backbone” connecting supply and demand, but also a key factor in ensuring energy security, strengthening operational flexibility, and optimizing the efficiency of the national power system.

Space requirement

The safety protection corridor of overhead power transmission lines is a spatial area along the line, defined in terms of length, width, and height [8].

Length of the corridor: The length of the corridor is calculated from the point where the transmission line exits the protection boundary of one substation to the point where it enters the protection boundary of the next substation. This regulation applies to all voltage levels.

Width of the corridor: The width of the corridor is limited by two vertical planes on both sides of the line, parallel to the line, with a distance from the outermost conductor on each side when the conductor is in a static state, as regulated below:

- For 220 kV lines: The distance from the outermost conductor on each side is 6.0 meters.
- For 500 kV lines: The distance from the outermost conductor on each side is 7.0 meters.

Height of the corridor: The height of the corridor is calculated from the foundation base of the tower to the highest point of the structure, plus the safety clearance in the vertical direction as regulated below:

- For 220 kV lines: The additional clearance is 4.0 meters.
- For 500 kV lines: The additional clearance is 6.0 meters.

Accordingly, the corridor of a 220 kV transmission line is estimated at about 22 – 23 m, while that of a 500 kV line is estimated at about 32 – 40 m. Under Vietnamese regulations, trees and structures may still be located within the corridor provided that the safety clearance is ensured. The temporary land acquisition for transmission line projects is calculated based on the area of the tower foundations.

For substations, the land requirement for one 500 kV AIS substation is about 20 – 25 ha and for one 220 kV AIS substation is about 4 – 8 ha. The land area required for an indoor GIS substation is only about half that of an outdoor AIS substation of the same scale and capacity.

Environment

The environmental impacts of the electrical grid systems are mainly

- Visual impacts – Overhead lines are often considered to have a negative aesthetic impact on the surroundings
- Electromagnetic fields – Electricity infrastructure produces both electric and magnetic fields that may be harmful. Exposure to electric and magnetic fields is regulated and appropriate safety distances are assured when establishing and operating electrical transmission infrastructure [9].
- Land occupation, resettlement, and ecosystem fragmentation – Transmission line projects exert significant impacts on land use by occupying large areas, creating challenges for compensation, site clearance, and generating resettlement needs. At the same time, their construction and operation

may fragment ecosystems, convert forest land, and traverse protected areas and tourism landscapes, thereby reducing certain ecosystem services and affecting the livelihoods of local communities.

- Noise – Sizzles, crackles and hissing noises occur around high voltage overhead lines during periods of high humidity. Transformers emit humming sounds. These noises are audible only at close vicinity to the equipment. Noise during construction and maintenance can have an impact on the environment.
- Electrical hazard – Safety requirements on design and operation are established to assure safe design and operation of electric facilities.
- SF_6 gas is often used in gas insulated substations. SF_6 is a strong climate gas[3].

Research and development

Alternating current (AC) power transmission technologies are already mature worldwide. Current research directions globally mainly focus on digitalization and decarbonization. In Viet Nam, the specific research directions include the following:

- **Research on Flexible AC Transmission Systems (FACTS)**: Research and development of Flexible AC Transmission Systems (FACTS) aim to optimize the transmission capacity of AC power systems while enhancing system stability and interconnection capability among regional power grids. Research directions may include both the development of materials for manufacturing equipment and issues related to the design, integration, operation, and control of FACTS devices within power systems.
- **Research on smart grids**: Smart grid technology not only enables power transmission but also enhances the capability for information transmission and exchange within the power system, thereby improving system reliability, cybersecurity, and operational efficiency. Key research directions may include the operation and management of rooftop solar power systems, the application of voltage-regulating distribution transformers, and research on data exchange protocols and connectivity for data centres within the power system.
- **Research on digitalization and digital transformation in power system operation**: Research on digitalization and digital transformation focuses on the application of digital technologies to improve operational efficiency, management, and reliability of the power system. One important research direction is the development of digital substations, in which conventional substations are converted into digital substations and eventually unmanned substations, thereby optimizing operational costs and improving system reliability. The share of unmanned substations in Viet Nam is increasing rapidly, with a target of reaching 100% of 110 kV and 220 kV substations by 2030. In addition, research on data-driven asset management is also receiving increasing attention, through the application of artificial intelligence (AI) and big data (Big Data) to analyse equipment conditions and implement predictive maintenance solutions, thereby extending equipment lifetime and improving the efficiency of grid asset management.

Examples of current projects

500 kV North–South national power transmission line

The 500 kV North–South Inter-regional Transmission Line is one of Vietnam’s most important ultra-high-voltage power grid projects, often referred to as the “backbone” of the national electricity system. This project marked a significant milestone in forming a continuous 500 kV transmission network linking the North, Central, and South of the country.

Circuit 1 (1992–1994):

The first 500 kV line from Hoa Binh (North) to Phu Lam – Ho Chi Minh City (South) was inaugurated. It spans nearly 1,500 kilometers and transmits electricity from major hydropower plants in the North to support the electricity-deficient South. This century-defining project was completed in just two years.

Circuit 2:

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[3] The amended F-Gas Regulation (EU) 2024/573, aims for a complete phase-out of F-gases by 2050. Including a complete phase-out of SF6 for transformers in 2032.

The second circuit was completed in 2005, enhancing system reliability, reducing power losses, and increasing North–South transmission capacity. This project was entirely undertaken by Vietnamese engineers and workers, from design and construction to steel tower manufacturing, supervision, and commissioning.

Circuit 3:

The third 500 kV transmission line runs from Quang Trach (Quang Binh) to Pho Noi (Hung Yen), stretching approximately 519 km. This double-circuit line traverses diverse terrains, resulting in a heavy workload. Despite this, construction was completed in just over 6 months.

Key Features:

- The 500 kV system links the North, Central, and South with multiple parallel transmission lines and important substations (e.g., Hoa Binh, Ha Tinh, Da Nang, Pleiku, Phu Lam...).
- The total length of the 500 kV North–South transmission network exceeds 3,000 km.
- Acts as a backbone, transmitting power between regions..

Importance of the 500 kV Inter-regional Transmission System:

- Ensures national energy security by balancing electricity supply and demand across regions.
- Effectively leverage geographical and natural advantages to support power generation development.
- Reduces the need for local generation investments, optimizing the operation of the entire national power system.

Uncertainty

Performance data of electrical grid, such as energy losses, technical lifetime and load profile typically depends on techno-economic-market considerations such as amount of energy transfer to adjacent countries, value of energy loss, lifetime vs. investment costs, etc. Changes in regulations, economic and political foundations may have impact on the performance data. Furthermore, large changes on the basic design and operation of the grid will have impact on both performance and costs that are difficult to anticipate.

Prediction of performance and cost

To enable comparative analyses between different technologies it is imperative that data are actually comparable: All cost data are stated in fixed prices/real terms (price level 2025) excluding value added taxes (VAT) and other taxes. Investment costs (CAPEX) include purchase and installation. The information given in the tables relate to the development status of the technology at the point of final investment decision (FID) in the given year (2025, 2030, 2035, 2040 and 2050).

The inflation rates for Vietnam on average have been [10]:

- Vietnam inflation rate for 2024 was 3.6%
- Vietnam inflation rate for 2023 was 3.3%
- Vietnam inflation rate for 2022 was 3.2%
- Vietnam inflation rate for 2021 was 1.8%
- Vietnam inflation rate for 2020 was 3.2%

FID is assumed to be taken when financing of a project is secured, and all permits are at hand. The year of commissioning will depend on the construction time of the individual technologies after permits have been received.

The quantitative data are described in tables in this report and supplementary datasheets. Data contains parameters used to describe the specific transmission components.

The uncertainty of numbers is in general assessed as plus/minus 30 %.

The evaluation of costs and performance is based on the following main sources:

1. EVN, Investment capital norms for the construction of substation and transmission line projects at voltage levels from 110 kV to 500 kV, January 2023 [11].

2. Investment cost rates for construction and the aggregated construction price for structural components issued together with Decision No. 816/QĐ-BXD dated August 22, 2024, by the Ministry of Construction.
3. Statistics on the total investment costs of selected actual power grid projects in Vietnam during the period 2021–2025.

Source 1 and 2 is an official document published by EVN and Ministry of Construction on investment capital norms for the construction of substations and transmission lines. In which, investment cost in source 1 is consistent with the EVN's regulations on the design of transmission grid projects. The document includes data tables presenting investment cost norms for various types of transmission lines and substations typical in Vietnam. It serves as a reference for preliminary estimation of investment costs (during project planning, investment policy approval, and capital budgeting), and as a tool for managing construction investment costs during project preparation, as well as for cross-checking total investment values in the processes of preparation, appraisal, and approval of projects. Since EVN is currently the sole investor responsible for developing the transmission grid in Vietnam, referencing data from EVN's publications is both reliable and reflective of actual conditions.

Source 3 consists of a database compiled by a group of domestic experts, reflecting the actual total investment costs of transmission line and substation projects commissioned in the 2021–2025 period in Vietnam. The data were collected from official sources, including information published on websites reporting project energization progress, feasibility study reports, and direct technical exchanges with experts in the field of power transmission.

According to EVN's published investment capital norms for the construction of substations and transmission lines, the growth rate of CAPEX of transmission assets is as follows:

- Costs of 500 kV substations have increased by about 10-20%
- Costs of 220 kV substations have increased by about 15-20%
- Costs of 500 kV AC transmission line have increased by about 50-80%
- Costs of 220 kV AC transmission line have increased by about 40-80%

For the 2025 benchmark data, the expert team refers to the investment capital norms published by EVN in 2023. Transmission cost data released in 2023 are typically based on reference projects implemented two to three years earlier or even older. Therefore, the estimated 2025 costs are adjusted upward in line with the actual total investment of grid projects commissioned during 2023–2025.

In 2024, changes in load-bearing standards led to revisions in the design regulations for transmission lines, causing total investment costs of grid projects to increase significantly compared to the 2023 investment norms. As a result, for all assets, prices are generally raised by about 50–80% as a preliminary adjustment to reflect 2025 cost levels. This implies that part or most of the price fluctuations had already been captured, for example, in the 2023 reference data. However, it should be noted that cost increases due to changes in design standards were abrupt and non-linear over time.

According to contacted transmission sector stakeholders, the main reasons for the surging prices over the last years can be summarised as follows:

- After the COVID-19 pandemic, demand for transmission assets surged due to renewed activity in the energy field. This caused an imbalance between demand and supply. The supply chains became challenged and still are.
- Significantly increased interest rates increased the general cost basis of supplier business, which raised supplier bids in tenders.
- Additional demand increase took place because of the general trend of energy systems going from “fossil fueled” to “green”, a development that calls for new investments in the transmission network.
- Increased prices of raw materials.
- Different ongoing conflicts around the world have had global macroeconomic effect and have also meant that important manufacturing capacity and supply lines have been destroyed or disrupted.

Stakeholders from the transmission industry expect the prices to level out, but they do not foresee a downward movement of prices in the near future (in real terms). Even with new factories producing transmission assets being built in e.g. India, China, Germany and US they expect the supply capacity to be lower than the demand for years to come.

In this catalogue we have assumed that in the market in the longer term we will again attain an equilibrium between supply and demand when new factories for transmission assets have been built. Consequently, we have assumed continued high prices until 2030 and thereafter a decline in prices towards 2050. In 2050 the prices are assumed to be back (in real terms) to prices before the assumed 40-80% price rise.

Technical data for AC transmission

The parameters on losses and load-carrying capacities of grid components are determined based on typical equipment configurations used in Vietnam's power system. It should be emphasized that these technical figures are entirely estimated through technical analysis, using information published in manufacturers' catalogues. In actual operation, when equipment operates under environmental conditions that differ from standard or ideal conditions, the technical parameters may not achieve the values estimated below.

Table 3: Energy losses for line and substation

Item	Value
Energy losses, OH lines 500 kV AC [%/100 km] at rated power	0.89% - 1.39%
Energy losses, OH lines 220 kV AC [%/100 km] at rated power	2.31% - 3.51%
Energy losses, cables AC [%/100 km] at rated power	0.35%- 1.05%
Energy losses, AC substation [%]	0.89% - 1.39%
Energy losses, Transformer [%]	0.35%- 1.05%

Table 4 Capacity of typical AC lines and cables (by thermal limit)[4]

	Item	Value
OH line	500 kV AC, conductor size ACSR4x330	2000 MW
	500 kV AC, conductor size ACSR4x400	2200 MW
	500 kV AC, conductor size ACSR4x500	3100 MW
	500 kV AC, conductor size ACSR4x600	3400 MW
	220 kV AC, conductor size ACSR500	340 MW
	220 kV AC, conductor size ACSR2x330	500 MW
	220 kV AC, conductor size ACSR2x400	600 MW
	220 kV AC, conductor size ACSR3x400	900 MW
Cable	220kV underground cables	400 MW
	220kV sea cables	400 MW

Economic data for AC OH-lines

For overhead AC transmission lines, the 2025 benchmark economic data are compiled from EVN's 2023 publication on investment capital norms for transmission projects. The investment costs are adjusted based on the total investment of selected actual projects commissioned during 2023–2025 to reflect cost increases. Compared to EVN's original data, the investment costs for transmission lines are increased by approximately 40–80% to align with 2025 price levels, mainly due to higher material prices and more stringent design standards. As EVN is currently the main investor in Vietnam's transmission grid projects,

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[4] For long transmission lines, the power transfer capacity is limited by stability conditions, which are significantly lower than the thermal limits of the conductors.

this source is considered appropriate and reliable. The total investment of EVN's transmission projects is thus referenced according to the published investment norms.

Investment costs for overhead lines are categorized by voltage level (500 kV – 220 kV) and by typical conductor cross-sections. The unit used in the economic data tables is mill USD/km.

Economic data for AC onshore and offshore cables

The economic data for cables are divided into two categories: underground cables and submarine cables.

To serve as a basis for constructing the technical–economic cable dataset, the 2025 benchmark data are derived from actual projects already commissioned in Vietnam. However, currently only 220 kV AC underground cable projects have been put into operation, so cable data remain limited. The technical parameters are calculated based on information from supplier catalogues, such as NKT and Cadivi. Economic data are compiled from actual operational cable line projects, such as Tao Dan – Tan Cang and Kien Binh – Phu Quoc. EVN's 2023 investment capital norms only provide information for 110 kV underground cables.

An estimation of investment costs for cable lines is made based on their ratio to the investment costs of overhead lines. According to technical discussions with transmission experts and suppliers, the investment cost of underground cables is typically about 10 times higher than that of overhead lines with the same load capacity. Submarine cable lines are generally 3–4 times more expensive than underground cables. The cost increase is mainly due to the special materials required and the high technical demands of construction and installation.

Cost forecast for AC OH-Lines and cables

As basis for the cost forecast the data from the German TSOs (Netz, 2023) is selected for OH-lines and cable systems. The argument is that (Netz, 2023) provide figures which must be assumed to be consistent between AC and DC and onshore/offshore, as prices come from the same source: the German TSOs. In addition, the German TSOs have large experience with transmission costs from their many projects. The forecasting performed by the German TSO is reflecting the European market situation, but have been applied to Vietnamese context. The main reasoning for applying European methodology to the Vietnam case is due to two main drivers for the cost projections which are similar for the two markets:

- Costs on transmission infrastructure have increased significantly from 2023-2025 on both the European and Vietnamese market. The 2025 base year is considered at state where the market is not in equilibrium, and in long term the market is expected to reach an equilibrium with lower prices.
- The key drivers for cost increase in 2025 have been similar in Vietnam and Europe; rising prices on materials, supply chain bottlenecks and new approaches in infrastructure best practices and standards

The methodology follows that the costs are assumed unchanged until 2030. From 2030 to 2050 the prices are assumed to decrease until the level before the 2025 uplift (40-80%). Thus, we have assumed that in the market in the longer term we will again attain an equilibrium between supply and demand. For consistency, all assets have decreased with 50% from 2030 to 2050 independent of the uplift level at 2025. The uncertainty interval (high and low values) for the financial parameters is assumed to be plus/minus 30% (in the datasheets).

The table below summarizes the results of the cost projections for selected OH-lines. Note that in general there is high variation in prices for each category. The prices therefore have a high uncertainty.

Table 5: The results of the cost projections for selected OH-lines

OH-line	Unit	2025	2030	2040	2050
Investment, OH lines 500 kV AC, conductor size ACSR4x330	mill USD/km	0.91	0.91	0.83	0.74
Investment, OH lines 500 kV AC, conductor size ACSR4x400	mill USD/km	1.09	1.09	0.97	0.86

OH-line	Unit	2025	2030	2040	2050
Investment, OH lines 500 kV AC, conductor size ACSR4x500	mill USD/km	1.23	1.23	1.11	1.00
Investment, OH lines 500 kV AC, conductor size ACSR4x600	mill USD/km	1.43	1.43	1.29	1.14
Investment, OH lines 220 kV AC, conductor size ACSR500	mill USD/km	0.24	0.24	0.22	0.19
Investment, OH lines 220 kV AC, conductor size ACSR2x330	mill USD/km	0.37	0.37	0.34	0.30
Investment, OH lines 220 kV AC, conductor size ACSR2x400	mill USD/km	0.47	0.47	0.43	0.38
Investment, OH lines 220 kV AC, conductor size ACSR3x400	mill USD/km	0.86	0.86	0.77	0.69

Table below summarizes the results of the cost projections for selected cables. Note that in general there is high variation in prices for each category. The prices therefore have a high uncertainty.

Table 6: The results of the cost projections for selected cables

Cable	Unit	2025	2030	2040	2050
AC 220 kV underground cables, 400 MW capacity	mill USD/km	2.84	2.84	2.56	2.27
AC 220 kV sea cables, 400 MW capacity	mill USD/km	6.00	6.00	5.40	4.80
AC 500 kV underground cables	mill USD/km	6.26	6.26	5.64	5.02
AC 500 kV sea cables	mill USD/km	13.25	13.25	11.92	10.60

Economic data for substations

Similar to transmission lines, the primary source used to construct the 2025 benchmark economic dataset for substations is EVN's 2023 publication on investment capital norms for transmission grid projects. Adjustments are made based on current prices of actual substations commissioned during 2023–2025. Since there have been few changes in technical construction standards compared to overhead lines, the 2025 investment capital for substations is estimated by adding approximately 10-20% to the original figures in EVN's 2023 document.

Investment costs for substations are categorized by typical 500 kV and 220 kV substation configurations, similar to EVN's published investment capital norms. Investment costs vary depending on the substation's capacity, number of transformers, number of transmission line bays, and other factors, making it necessary to break down costs by different substation components. For this economic dataset, the figures are based on AIS substations. GIS substations are still not widely used in Vietnam, so data availability is limited.

The unit of investment cost in the economic dataset is million USD/MVA or million USD/MW. It can be observed that the investment cost per MVA decreases as the substation's capacity increases.

Cost forecast for AC substations

As basis for cost forecast the data from (Netz, 2023) is selected for substations. The argument is that (Netz, 2023) provide forecasted figures which must be assumed to be consistent between AC and DC and onshore/offshore, since the method comes from the same source: the German TSOs. In addition, the German TSOs have large experience with substation costs from their many projects.

Table 7 summarizes the cost forecast for selected substations. Prices are assumed unchanged from 2025 to 2030. From 2030 to 2050 the prices are assumed to decrease (until the level before the 2025 uplift). For consistency, all assets have decreased with 20% from 2030 to 2050 independent of the uplift level at 2025 The uncertainty interval (high and low values) is assumed to be plus/minus 30% (in the datasheets).

Table 7: The results of the cost projections for selected substations

	Unit	2025	2030	2040	2050
500 kV AC onshore substation, 600 MVA capacity, 2 bay feeders of 500 kV line, 4 bay feeders of 220 kV line	Mill USD/MVA	0.030	0.030	0.027	0.024
500 kV AC onshore substation, 2x600 MVA capacity, 4 bay feeders of 500 kV line, 8 bay feeders of 220 kV line	Mill USD/MVA	0.024	0.024	0.021	0.019
500 kV AC onshore substation, 900 MVA capacity, 2 bay feeders of 500 kV line, 6 bay feeders of 220 kV line	Mill USD/MVA	0.023	0.023	0.020	0.018
500 kV AC onshore substation, 2x900 MVA capacity, 4 bay feeders of 500 kV line, 8 bay feeders of 220 kV line	Mill USD/MVA	0.018	0.018	0.016	0.014
220 kV AC onshore substation, 125 MVA capacity, 2 bay feeders of 220 kV line, 4 bay feeders of 110 kV line	Mill USD/MVA	0.066	0.066	0.059	0.052
220 kV AC onshore substation, 2x125 MVA capacity, 4 bay feeders of 220 kV line, 6 bay feeders of 110 kV line	Mill USD/MVA	0.043	0.043	0.039	0.035
220 kV AC onshore substation, 250 MVA capacity, 4 bay feeders of 220 kV line, 6 bay feeders of 110 kV line	Mill USD/MVA	0.038	0.038	0.034	0.031
AC offshore substation, incl. platform, 500 MVA capacity	Mill USD/MVA	0.076	0.076	0.068	0.061

Economic data for transformers

Transformers will normally be a part of a substation, and their costs will be included in the substation cost (also in this catalogue).

Investment costs for transformers are referenced from the Specialized Equipment Price Tables in EVN’s 2023 publication on investment capital norms. The 2025 investment capital for substations is estimated by adding approximately 10-20% to the original figures in EVN’s 2023 document. Additionally, information is supplemented through technical discussions with transformer suppliers commonly active in the Vietnamese market, including domestic manufacturers such as Dong Anh Electric Equipment Corporation and international producers like Toshiba and Hitachi. Transformer investment costs vary significantly between manufacturers, depending on applied technical standards (e.g., IEC or IEEE), manufacturing technology, materials used, and the level of automation in production. European manufacturers typically adhere strictly to international technical and quality standards, with rigorous testing procedures and high-quality materials. Consequently, transformer prices from European companies are generally higher than those from Chinese manufacturers, who often offer more competitive pricing due to economies of scale and lower labour costs.

In terms of investment cost per MVA (million USD/MVA), larger-capacity transformers tend to have lower unit investment costs. This is because, when manufacturing higher-capacity units, the material and production costs do not increase proportionally with capacity. Many components, such as the tank, tap changer, and cooling system, remain relatively similar across different capacity levels.

As basis for cost performance the data from [12] is selected for transformers. The argument is that [12]provide figures from the German TSOs, who have large experience with transformers from their many projects. Besides, prices from [12] have been selected for other transmission components. Where shown, figures for 2025 are estimated by adding 20% to the price from source (2020 price level). The increase is explained by higher material cost, supply chain bottlenecks etc. The 20% is an estimate based on informal talks with industry stakeholders in the power transmission sector (primarily in Denmark) and the assumption that part of the price rise over the last years has been reflected in the 2023 prices.

Table 8 summarizes the cost forecast for selected transformers.

Table 8: The results of the cost projections for selected transformer

Transformer	Unit	2025	2030	2040	2050
500/220 kV, 900 MVA	Mill USD/MVA	0.012	0.012	0.010	0.009
500/220 kV, 600 MVA	Mill USD/MVA	0.015	0.015	0.013	0.012
500/220 kV, 450 MVA	Mill USD/MVA	0.016	0.016	0.015	0.013
220/110 kV, 250 MVA	Mill USD/MVA	0.019	0.019	0.017	0.015
220/110 kV, 125 MVA	Mill USD/MVA	0.026	0.026	0.023	0.020

Economic data for compensation

Compensation is used to control voltage and transfer capacity of the transmission grid. Compensation is in the form of reactive power provided or consumed by means of capacitor banks, reactors, SVCs and STATCOMs (see qualitative chapter).

Since data on compensation equipment, especially FACTS devices, is not readily available in Vietnam, the datasheet has been developed based on references from the Technology Catalogue for Energy Transport of Denmark, 2025 version. The data in Table 9 is from US, MISO (system operator) [13]; the data in Table 10 is from Germany (Netzentwicklungsplan, version 2021) [12].

2025 prices have been estimated by adding 10-20% to the price from source. The increase is explained by higher material cost, supply chain bottlenecks etc.

By comparing 2025 figures in Table 9 with corresponding figures in Table 10 it is seen that US figures for STATCOM and SVC are about 45% and 90% higher that German figures, respectively. For capacitor banks and reactors, German prices are significantly higher than US prices.

Table 9: Economic data for compensation, US data

Voltage	69 kV	115 kV	138 kV	161 kV	230 kV	345 kV	500 kV	765 kV	Reference	Note
Reactor (kEUR/MVAr)	16	16	16	16	16	16	25	36	1	1, 2, 3, 4
Capacitor bank (kEUR/MVAr)	12	12	12	12	12	12	12	12	1	1, 2, 3, 4
SVC (kEUR/MVAr)	115	115	115	115	115	115	115	115	1	1, 2, 3, 4
STATCOM (kEUR/MVAr)	227	227	227	227	227	227	227	227	1	1, 2, 3, 4

References
1. Transmission cost estimation guide for MTEP22, April 2022

Notes
1. MVAr: MVA reactive power
2. Unit costs include all material, shipping, foundation and installation costs, taxes (not specified) and contingency
3. Original prices in 2022: 0,951 EUR/$
4. Price in 2025: additional 20% to price from original source

Table 10: Economic data for compensation, European data (Germany)

			Unit	Price, original from source	Price level 2020	2025	Reference	Note
[22]	380 kV, 100 MVAr	Capacitor bank	kEUR/MVAr	20	20	24	1	1
[22]	380 kV, SVC	SVC	kEUR/MVAr	50	50	60	1	1
[22]	380 kV, 100 MVAr	Reactor	kEUR/MVAr	21	21	25	1	1
[22]	380 kV	STATCOM	kEUR/MVAr	130	129	155	1	1

References

1. Netzentwicklungsplan Strom (TSO Đức), phiên bản 2021

Note

1. Price in 2025: additional 20% to price from original source

Table 11: The results of the cost projections for selected compensation

Compensation	Unit	2025	2030	2040	2050
Capacitor bank	Mill USD/MVAr	0.034	0.034	0.031	0.027
SVC	Mill USD/MVAr	0.086	0.086	0.077	0.069
Reactor	Mill USD/MVAr	0.036	0.036	0.032	0.029
STATCOM	Mill USD/MVAr	0.222	0.222	0.199	0.180

Economic data, O&M

The annual costs of operating and maintaining the transmission system components vary due to system design, materials, climate, age etc. Often the costs are assumed to be a percentage per year of the investment cost (CAPEX). For all assets – OH-lines, cables, substations, transformers and compensation - the fixed O&M values are set as 2% (of CAPEX per year). It can be argued that O&M costs would not increase with the same rate as an abrupt CAPEX increase. However, for the sake of simplicity the percentages are kept unchanged from 2025-2050.

References

[1] Law No. 61/2024/QH15 of the National Assembly: Law on Electricity.

[2] Law No. 03/2022/QH15 amending and supplementing a number of articles of the Law on Public Investment, the Law on Investment in the form of Public-Private Partnership, the Law on Investment, the Law on Housing, the Law on Bidding, the Law on Electricity.

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Data sheet

Overhead lines AC (double circuit)													
Parameter	**Unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
								Lower	**Upper**	**Lower**	**Upper**	**-**	**-**
Energy/technical data													
Energy losses, OH lines 500 kV AC at rated power	%/100 km	1.14%	1.14%	1.14%	1.14%	1.14%	1.14%	0.89%	1.39%	0.89%	1.39%		4
Energy losses, OH lines 220 kV AC at rated power	%/100 km	2.91%	2.91%	2.91%	2.91%	2.91%	2.91%	2.31%	3.51%	2.31%	3.51%		4
Technical life time	years	50	50	50	50	50	50	40	70	40	70		1
Typical load factor	%	60%	60%	60%	60%	60%	60%	50%	70%	50%	70%		
Construction time	years	2	2	2	2	2	2	1	3	1	3		1
Economic data													
Investment, OH lines 500 kV AC, conductor size ACSR4x330	mill USD/km	0.91	0.91	0.89	0.83	0.77	0.74	0.66	1.20	0.51	0.94	A, B, C, D, E, F	3
Investment, OH lines 500 kV AC, conductor size ACSR4x400	mill USD/km	1.09	1.09	1.03	0.97	0.91	0.86	0.74	1.40	0.60	1.11	A, B, C, D, E, F	3
Investment, OH lines 500 kV AC, conductor size ACSR4x500	mill USD/km	1.23	1.23	1.17	1.11	1.06	1.00	0.86	1.60	0.69	1.29	A, B, C, D, E, F	2
Investment, OH lines 500 kV AC, conductor size ACSR4x600	mill USD/km	1.43	1.43	1.34	1.29	1.20	1.14	1.00	1.86	0.80	1.49	A, B, C, D, E, F	2
Investment, OH lines 220 kV AC, conductor size ACSR500	mill USD/km	0.24	0.24	0.23	0.22	0.21	0.19	0.17	0.32	0.14	0.25	A, B, C, D, E, F	3
Investment, OH lines 220 kV AC, conductor size ACSR2x330	mill USD/km	0.37	0.37	0.35	0.34	0.31	0.30	0.26	0.49	0.21	0.39	A, B, C, D, E, F	3
Investment, OH lines 220 kV AC, conductor size ACSR2x400	mill USD/km	0.47	0.47	0.45	0.43	0.40	0.38	0.33	0.62	0.27	0.50	A, B, C, D, E, F	3
Investment, OH lines 220 kV AC, conductor size ACSR3x400	mill USD/km	0.86	0.86	0.82	0.77	0.73	0.69	0.60	1.12	0.49	0.90	A, B, C, D, E, F	3
Investments, installation	%	30%	30%	30%	30%	30%	30%	-	-	-	-		2, 3
Investments, materials	%	57%	57%	57%	57%	57%	57%	-	-	-	-		2, 3
Additional costs	%	13%	13%	13%	13%	13%	13%	-	-	-	-		2, 3
Fixed O&M	% of CAPEX/year	2%	2%	2%	2%	2%	2%	-	-	-	-		2, 3
Variable O&M	USD/MWh/km	-	-	-	-	-	-	-	-	-	-		

Notes:

A The value is significantly lower than European sources.

B Lower and upper uncertainties are minus/plus 30%.

C Prices assumed to decrease linearly from 2030 to 2050 with 20%.

D Unit cost is corresponding to installation in weak soil conditions and routes passing through forests.

E The investment cost of a single circuit is about 0.7 times that of a double circuit.

F The Danish Technology Catalogue expresses investment costs in USD/km/MW. However, in Vietnam, transmission line investment costs are typically calculated in USD/km. To convert between these units, the cost in USD/km can be divided by the rated transmission capacity of the line to obtain the cost in USD/km/MW.

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4 Technical parameters from catalogue of overhead conductors

Cables AC

Parameter	Unit	2025	2030	2035	2040	2045	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
								Lower	Upper	Lower	Upper		
Energy/technical data													
Energy losses, cables AC at rated power	%/100 km	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	0.50%	1.93%	0.50%	1.93%		2
Technical life time	years	40	40	40	40	40	40	25	40	25	40		2
Typical load factor	%	60%	60%	60%	60%	60%	60%	50%	70%	50%	70%		
Construction time	years	2	2	2	2	2	2						2
Economic data													
AC 220kV underground cables, 400 MW capacity	mill USD/km	2.84	2.84	2.70	2.56	2.42	2.27	1.99	3.69	1.59	2.95	A, B, C, E	1, 2, 3
AC 220 kV sea cables, 400 MW capacity	mill USD/km	6.00	6.00	5.70	5.40	5.10	4.80	4.20	7.80	3.36	6.24	A, B, C, E	1, 2, 3
AC 500kV underground cables	mill USD/km	6.26	6.26	5.95	5.64	5.33	5.02	4.39	8.15	3.52	6.52	A, B, C, D, E	1, 2, 3, 4
AC 500kV sea cables	mill USD/km	13.25	13.25	12.59	11.92	11.26	10.60	9.28	17.22	7.42	13.78	A, B, C, D, E	1, 2, 3, 4
Investments, installation	%	30%	30%	30%	30%	30%	30%	-	-	-	-		1, 2
Investments, materials	%	57%	57%	57%	57%	57%	57%	-	-	-	-		1, 2
Additional costs	%	13%	13%	13%	13%	13%	13%	-	-	-	-		1, 2
Fixed O&M	% of CAPEX/year	2%	2%	2%	2%	2%	2%	-	-	-	-		1, 2
Variable O&M	USD/MWh/km	-	-	-	-	-	-	-	-	-	-		

Notes:

A Lower and upper uncertainties are minus/plus 30%.
B Prices assumed to decrease linearly from 2030 to 2050 with 20%.
C The investment cost excludes compensation, support and resettlement costs, interest during construction, initial working capital, contingency costs, and VAT.
D Based on the investment cost for the AC 220 kV underground cable, 400 MW and the ratio between investment costs for an AC 220 kV sea cable and an AC 500 kV underground cable in [4].
E The Danish Technology Catalogue expresses investment costs in USD/km/MW. However, in Vietnam, transmission line investment costs are typically calculated in USD/km. To convert between these units, the cost in USD/km can be divided by the rated transmission capacity of the line to obtain the cost in USD/km/MW.

References

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2 Keith Bell, John Loughhead, Andrew Lovett, Katherine Jackson, and David Reid, “A comparison of electricity transmission technologies: Costs and characteristics.” [Online]. Available: https://www.theiet.org/media/axwkktkb/100110238_001-rev-j-electricity-transmission-costs-and-characteristics_final-full.pdf
3 Investment rate of real project in Vietnam
4 ACER, pwc, UIC, 2023

Substations AC, Onshore and Offshore													
Parameter	**Unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
								Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data													
Energy losses, substation	%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.35%	1.05%	0.35%	1.05%		4, 5
Technical life time	years	40	40	40	40	40	40	20	40	20	40		4
Typical load factor	%	60%	60%	60%	60%	60%	60%	50%	70%	50%	70%		
Construction time	years	2	2	2	2	2	2	-	-	-	-	A	
Economic data													
500 kV AC onshore substation, 600 MVA capacity, 2 bay feeders of 500 kV line, 4 bay feeders of 220 kV line	Mill USD/MVA	0.030	0.030	0.029	0.027	0.026	0.024	0.021	0.039	0.017	0.031	B, C, D, E	2
500 kV AC onshore substation, 2x600 MVA capacity, 4 bay feeders of 500 kV line, 8 bay feeders of 220 kV line	Mill USD/MVA	0.024	0.024	0.023	0.021	0.020	0.019	0.017	0.031	0.013	0.025	B, C, D, E	2
500 kV AC onshore substation, 900 MVA capacity, 2 bay feeders of 500 kV line, 6 bay feeders of 220 kV line	Mill USD/MVA	0.023	0.023	0.022	0.020	0.019	0.018	0.016	0.030	0.013	0.024	B, C, D, E	2
500 kV AC onshore substation, 2x900 MVA capacity, 4 bay feeders of 500 kV line, 8 bay feeders of 220 kV line	Mill USD/MVA	0.018	0.018	0.017	0.016	0.015	0.014	0.012	0.023	0.010	0.018	B, C, D, E	2
220 kV AC onshore substation, 125 MVA capacity, 2 bay feeders of 220 kV line, 4 bay feeders of 110 kV line	Mill USD/MVA	0.066	0.066	0.062	0.059	0.056	0.052	0.046	0.085	0.037	0.068	B, C, D, E	2
220 kV AC onshore substation, 2x125 MVA capacity, 4 bay feeders of 220 kV line, 6 bay feeders of 110 kV line	Mill USD/MVA	0.043	0.043	0.041	0.039	0.037	0.035	0.030	0.056	0.024	0.045	B, C, D, E	2
220 kV AC onshore substation, 250 MVA capacity, 4 bay feeders of 220 kV line, 6 bay feeders of 110 kV line	Mill USD/MVA	0.038	0.038	0.036	0.034	0.033	0.031	0.027	0.050	0.021	0.040	B, C, D, E	2
AC offshore substation, incl. platform, 500 MVA capacity	Mill USD/MVA	0.076	0.076	0.072	0.068	0.065	0.061	0.053	0.099	0.042	0.079	B, C, D, E	1, 3, 4
Investments, installation	%	27%	27%	27%	27%	27%	27%	-	-	-	-		1, 4
Investments, materials	%	60%	60%	60%	60%	60%	60%	-	-	-	-		1, 4
Additional costs	%	13%	13%	13%	13%	13%	13%	-	-	-	-		1, 4
Fixed O&M	% of CAPEX/year	2%	2%	2%	2%	2%	2%	-	-	-	-		
Variable O&M	USD/MWh/km	-	-	-	-	-	-	-	-	-	-		

Notes:

A Project specific, depends on size and location of station.

B Investment cost includes civil works, equipment supply and installation, testing and commissioning, project management, engineering/consultancy, and other related project costs for the defined standard substation configuration including the specified bays; it excludes land acquisition/resettlement, financing during construction, contingency, special geotechnical treatment, site grading, and VAT.

C The investment cost excludes compensation, support and resettlement costs, interest during construction, initial working capital, contingency costs, and VAT.

D Prices assumed to decrease linearly from 2030 to 2050 with 20%.

E Lower and upper uncertainties are minus/plus 30%.

References

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3 T. A. Antunes, R. Castro, P. J. Santos, and A. J. Pires, “Technology Selection of High-Voltage Offshore Substations Based on Artificial Intelligence,” Energies, vol. 17, no. 17, Art. no. 17, Jan. 2024, doi: 10.3390/en17174278

4 “Ensuring reliability: Aging substation infrastructure replacement initiative continues to make progress - Basin Electric Power Cooperative.” [Online]. Available: https://www.basinelectric.com/news-center/basin-today-stories/Ensuring-reliability-Aging-substation-infrastructure-replacement-initiative-continues-to-make-progress

5 U.S. Department of Energy, Transmission and Distribution Components, Quadrennial Technology Review 2015

Transformers													
Parameter	**Unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
								Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data													
Energy losses, transformer	%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.17%	0.50%	0.17%	0.50%		4
Technical life time	years	30	30	30	30	30	30	20	40	20	40		1, 2
Typical load factor	%	60%	60%	60%	60%	60%	60%	-	-	-	-		
Construction time	years	1	1	1	1	1	1	-	-	-	-		1, 2
Economic data													
500/220 kV, 900 MVA	Mill USD/MVA	0.012	0.012	0.011	0.010	0.010	0.009	0.008	0.015	0.006	0.012	A, B, C	3
500/220 kV, 600 MVA	Mill USD/MVA	0.015	0.015	0.014	0.013	0.013	0.012	0.010	0.019	0.008	0.015	A, B, C	3
500/220 kV, 450 MVA	Mill USD/MVA	0.016	0.016	0.016	0.015	0.014	0.013	0.011	0.021	0.009	0.017	A, B, C	3
220/110 kV, 250 MVA	Mill USD/MVA	0.019	0.019	0.018	0.017	0.016	0.015	0.013	0.025	0.011	0.020	A, B, C	3
220/110 kV, 125 MVA	Mill USD/MVA	0.026	0.026	0.024	0.023	0.022	0.020	0.018	0.033	0.014	0.027	A, B, C	3
Investments, installation	%	27%	27%	27%	27%	27%	27%	-	-	-	-		3
Investments, materials	%	60%	60%	60%	60%	60%	60%	-	-	-	-		3
Additional costs	%	13%	13%	13%	13%	13%	13%	-	-	-	-		3
Fixed O&M	% of CAPEX/year	2%	2%	2%	2%	2%	2%	-	-	-	-		
Variable O&M	USD/MWh/km	-	-	-	-	-	-	-	-	-	-		

Notes:
A Lower and upper uncertainty are minus/plus 30%.
B Prices assumed to decrease linearly from 2030 to 2050 with 20%.
C The investment cost excludes compensation, support and resettlement costs, interest during construction, initial working capital, contingency costs, and VAT.

References

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2 R. Marketing, “Understanding Transformer Aging and Life Expectancy,” A Line EDS [Online]. Available: https://www.alineeds.com/understanding-transformer-aging-and-life-expectancy/
3 EVN 2023, Unit Capital Investment for the Construction of Power Grid Projects at Voltage Levels from 110kV to 500kV.
4 Technical Parameters from catalogue of transformers

Compensation													
Parameter	**Unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
								Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data													
Technical life time	years	40	40	40	40	40	40						
Typical load factor	%	60%	60%	60%	60%	60%	60%						1
Construction time	years	0.2	0.2	0.2	0.2	0.2	0.2						1
Economic data													
Capacitor bank	Mill USD/MVAr	0.034	0.034	0.0323	0.0306	0.0289	0.027	0.024	0.044	0.019	0.035	A, B	1
SVC	Mill USD/MVAr	0.086	0.086	0.0817	0.0774	0.0731	0.069	0.060	0.112	0.048	0.089	A, B	1
Reactor	Mill USD/MVAr	0.036	0.036	0.0342	0.0324	0.0306	0.029	0.025	0.047	0.020	0.037	A, B	1
STATCOM	Mill USD/MVAr	0.222	0.222	0.2109	0.1998	0.1887	0.18	0.155	0.289	0.124	0.231	A, B	1
Investments, installation	%	27%	27%	27%	27%	27%	27%	-	-	-	-		
Investments, materials	%	60%	60%	60%	60%	60%	60%	-	-	-	-		
Additional costs	%	13%	13%	13%	13%	13%	13%	-	-	-	-		
Fixed O&M	% of CAPEX/year	2%	2%	2%	2%	2%	2%	-	-	-	-		1
Variable O&M	USD/MWh/km	-	-	-	-	-	-	-	-	-	-		

Notes:
A Lower and upper uncertainty are minus/plus 30%.
B Prices assumed to decrease linearly from 2030 to 2050 with 20%.

References:
1 Danish Energy Agency, 2025 - Technology Data for Energy Transport

1.2. Direct current transmission

Brief technology description

Overview

Technology development has enabled the use of HVDC as a highly efficient alternative for transmission of electric power and for interconnecting power grids with different frequencies. A DC grid system is a grid system based on DC instead of AC. The connection to the fundamental AC grid system is made by AC/DC (near end) and DC/AC (remote end) converters [1].

Due to the expected increase in power transmission demand from the Central and Southern regions to the North in the future, Vietnam plans to develop additional high-voltage direct current (HVDC) transmission systems during the 2031–2035 period, transmitting power from the North Central and South-Central regions to the Northern region. Each system is expected to have a transmission capacity of approximately 5–10 GW.

DC grids can be designed as radial multi-terminal systems or in a meshed way, providing the characteristics of a grid. Two-terminal long-distance DC corridors emerged in the 1960s and in the 1970s, with the rapid advancements in power electronics and control systems. The first multi-terminal, non-meshed, HVDC system was commissioned in the 1990s.

Meshed multi-terminal DC grids (MTDC), in which feature more than one power-flow path between two grid terminals are still being examined at the research level to solve the challenges of integration with the AC meshed grid. The concept of DC grids may one day also allow the various large electricity networks to be interconnected on a global level. Furthermore, a DC overlay grid system is able to enhance the flexibility of the entire transmission grid, being able to cope with the characteristics of renewable power infeed in a more effective manner [1].

HVDC systems require terminal and costly converter stations, which is not required by HVAC. The cost per distance (excluding converters) for Over Head- transmission Lines (OHL) is however lower for HVDC systems, due to smaller space requirements, reduced number of conductors and reduced losses. With regard to cables, HVDC enables longer cable transmission due to the lack of capacitive[5] losses that are present in AC cables.

Figure 1 illustrates a typical layout of a HVDC converter substation (Greenlink, link between GB and Ireland) with converter hall, converter transformers, AC switchgear and busbars, harmonic filters[6], lightning towers, ancillary plant etc.

Figure 3: Example of layout of HVDC, VSC substation, Greenlink [2]

Figure 4 and Figure 5 illustrate a comparison of the investment costs for HVAC and HVDC systems along the transmission line length at transmission levels of 2000 MW and 5000 MW (using overhead line). The

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[5] A cable has high capacitance, because the conductors are close together (separated by an insulator). The AC cable is repeatedly charged and discharged (with the frequency). The charging current uses capacity of the cable and leaves less room for active power transmission.

[6] Harmonics are frequencies that are integer multiples of the fundamental frequency. HVDC converters generate both AC and DC harmonic currents and voltages. Filters are used to reduce harmonics and their adverse effects.

comparison results show that the investment cost for the HVDC system becomes competitive with the HVAC system at transmission distances of at least 700 km for 2000 MW and at least 500 km for 5000 MW.

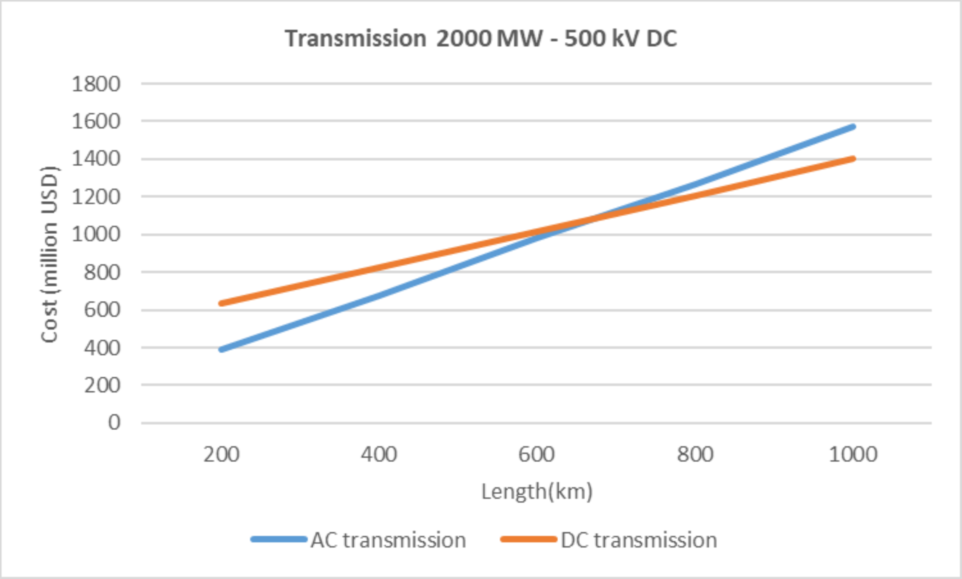

Figure 4: Cost comparisons of HVDC and HVAC systems by length (2000 MW)

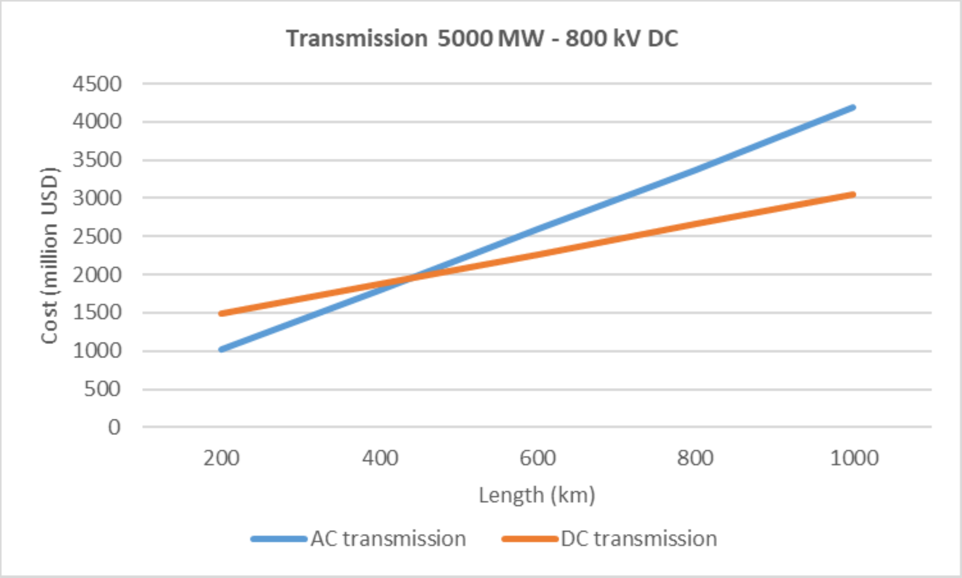

Figure 5: Cost comparisons of HVDC and HVAC systems by length (5000 MW)

The break-even distance for high voltage cable lines it is around 50 km [3]. Therefore, once a certain economic break-even point is exceeded, HVDC technology becomes cheaper than HVAC.

HVDC systems also enable a number of additional benefits, such as enhanced voltage regulation and controllability, ability to interconnect regions with different frequencies, providing fast power run-back or run-up[7], black start capability[8] etc. The choice between HVDC and HVAC is based on economical, technical, and environmental judgments.

Classification of HVDC systems

- ***By technology***

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[7] If a severe disturbance threatens system stability, HVDC can help maintain synchronized power-grid operation by fast power run-up (increase power flow on a line) or run-back (decrease power flow on a line) control functions.

[8] Black start is starting a power system from an un-energised state.

HVDC LCC system

Line-commutated converters (LCCs) are the conventional, mature and well-established technology used to convert electric power from AC to DC or vice versa. The term "line-commutated" indicates that the conversion process relies on a stable line voltage at both terminals of the HVDC system [1]. LCC HVDC systems use thyristor[9] valves, and the current commutation process depends on the voltage of the AC grid.

A LCC requires connection to a grid with sufficient short circuit power level to avoid commutation faults and a synchronous voltage source to operate (AC voltage at both terminals of the HVDC system). In comparison to a VSC, it still allows for higher power conversion capacities but would require converter stations with a larger ground footprint than the equivalent capacity VSC sites.

Advantages: Capable of handling very high voltages and currents, with low losses; commonly used in large-capacity, long-distance LCC-HVDC transmission systems.

Disadvantages: Highly dependent on the AC grid, lacks black-start capability after a power outage, and requires a sufficiently "strong" AC system for operation. The system generates harmonics, and LCC stations consume a large amount of reactive power (about 50–60% of the transmitted power) [4], requiring bulky harmonic filters and reactive power compensation equipment.

HVDC VSC system

Voltage Source Converters (VSC) are self-commutated[10] converters to connect HVAC and HVDC systems using devices suitable for high power electronic applications, such as IGBT[11]s (electronic switch). VSCs are capable of self-commutation, being able to generate AC voltages without the need to rely on an AC system. This allows for independent rapid control of both active and reactive power and black start capability [1].

VSCs maintain a constant polarity of the DC voltage for their building blocks. The change of power flow direction is achieved by reversing the direction of the current. VSC-based HVDC systems offer a fast active power flow control while also ensuring flexible and extended reactive power controllability at the two ends of the HVDC link.

Advantages: Compact station footprint, no need for large AC filters, suitable for space-constrained areas or offshore environments. VSC allows independent control of active and reactive power, has black-start capability without relying on the AC grid, can quickly restart after a blackout, and reduces harmonics.

Disadvantages: The rated capacity of VSC equipment is still limited compared to LCC technology. Power losses in converters are relatively high due to the use of high-frequency switching semiconductor devices. Equipment must withstand high electrical stress and dielectric requirements, increasing technical demands and investment costs. The control and design of VSC systems are complex, requiring advanced technology and specialized operational expertise.

HVDC systems based on hybrid LCC-VSC technology

At the current stage, hybrid HVDC (LCC-VSC) technology is an optimal solution as it combines the high efficiency and cost-effectiveness of LCC with the flexible controllability of VSC. This configuration is particularly effective for transmitting large amounts of power to load centres with weak or complex grid structures. In addition, the hybrid solution supports the transmission of renewable energy from generation areas to load centres (with sufficiently strong AC grids), helping stabilize power flows and optimize the integration of clean energy sources.

China Southern Power Grid (CSG) has commissioned the world's first hybrid station-to-station HVDC project, known as the Wudongde HVDC project. The success of this project demonstrates the technical feasibility of the hybrid station-to-station HVDC configuration. This hybrid HVDC system consists of three terminal stations: one LCC rectifier station (8000 MW) and two VSC inverter stations (5000 MW and 3000

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[9] A thyristor is a high-power semiconductor device that is triggered by a gate pulse but cannot turn off on its own. The turn-off process depends on the current through the valve dropping to zero or the presence of reverse voltage; therefore, an AC grid voltage is required to perform commutation.

[10] Voltage Source Converters (VSC) are self-commutated converters to connect HVAC and HVDC systems using devices suitable for high power electronic applications, such as IGBTs. VSCs are capable of self-commutation: being able to generate AC voltages without the need to rely on an AC system.

[11] Insulated-gate bipolar transistor

MW), with a rated DC voltage of ±800 kV and a total transmission capacity of 8000 MW. The total transmission line length is approximately 1452 km. The project uses conventional LCC technology at the sending end and VSC technology at both receiving ends.

In addition to Wudongde, hybrid HVDC technology is being widely deployed in other major projects. Notable examples include the Baihetan–Jiangsu project (China), which uses a hierarchical hybrid configuration to eliminate commutation failures at the receiving station. In Europe, the Skagerrak 4 system (Norway–Denmark) operates VSC and LCC in parallel to leverage black-start capability and voltage stability. Other projects such as Ultranet (Germany) and planned developments in India are also adopting this model to optimize the long-distance transmission cost advantages of LCC and the flexibility of VSC in weak grid areas.

❖ *By configuration*

HVDC- point to point

In the TYNDP-22 (ENTSO-E’s Ten-Year Network Development Plan) [10] many HVDC point to point projects have been promoted. The projects are typically interconnectors between countries/synchronous areas involving long sea cables. For illustration the capital costs of a selection of proposed new projects are shown in Figure 6 It follows that the left part of the figure has the best approximation to being linear (Coefficient of determination R^2=0,76). Figure 6 includes heterogenous projects with regard to converter types (VSC/LCC and onshore/offshore cables etc.).

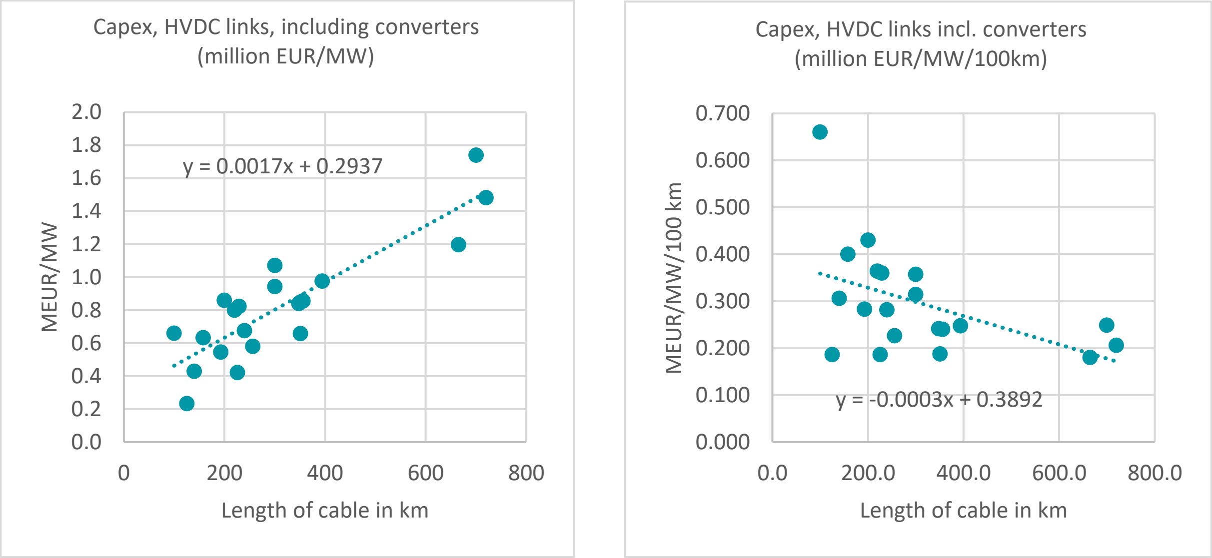

Figure 6: Investment cost of HVDC link in EU

It can be observed that as the transmission distance increases, the investment cost per unit of capacity rises. However, the investment cost per unit of capacity per unit length decreases. Therefore, the longer the transmission distance, the more cost-effective the HVDC system becomes.

New technology – multi-terminals

A few multi-terminal direct current (MTDC) systems are in operation around the world today, mainly concentrate in China. However, MTDC grids overlaying their AC counterpart might be a reality in a near future. The main driver for constructing such DC grids is the large-scale integration of remote renewable energy resources into the existing AC grids.

DC overlay systems can be designed as radial multi-terminal systems or in a meshed way, providing the characteristics of a grid with more than one DC power-flow path between two DC grid terminals.

Radial MTDC systems

Two-terminal long-distance DC corridors emerged in the 1960s and, with the rapid advancements in power electronics and control systems, the first multi-terminal, non-meshed, HVDC system was commissioned in the 1990s.

Figure 7 shows the Zhoushan 5-DC-Terminal project from 2014. It is a five terminal DC project at high voltage level. The five-terminal system connects five islands with the main power grid providing power for stabilizing the weak power grids on the islands. The system is designed as a radial multi-terminal system in a non-fault selective way, which results in a disconnection of the five terminals in case of a DC fault. A refurbishment with DC circuit breakers (DCCB) has later been implemented[12].

Another multiterminal project is the Sardinia-Corsica-Italy radial system [12]. The point-to-point 200 MW, 200 kV DC interconnection between Italy and Sardinia was extended in 1988 with an MTDC station of 50 MW in Corsica. The three MTDC stations form together the SACOI interconnection which operates as an MTDC system.

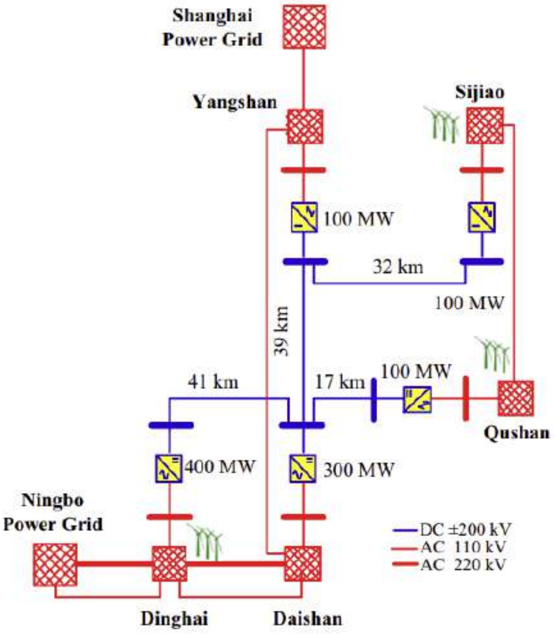

Figure 7: Zhoushan 5-Terminal DC project, China [6]

Authorities, TSOs, wind industry and other stakeholders of countries around the North Sea have reviewed the potential large-scale coordinated infrastructure over the past decade. A recent example is the large-scale North Sea Wind Power Hub proposed by, among others, TenneT NL, TenneT DE and Energinet. The whole system is intended to function as a hub for wind power transport via a multiterminal system transmitting power from the hub to several connected countries.

Meshed MTDC systems

Meshed multi-terminal DC grids, in which feature more than one DC power-flow path between two grid terminals, are still being examined at research level to solve the challenges of integration with the AC meshed grid [5]. Figure below is an illustration of a meshed multiterminal overlaid DC grid.

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[12] In the later Zhangbei project, 16 DCCBs of different types have been installed. One type is a further development of the type used in the Zhoushan project.

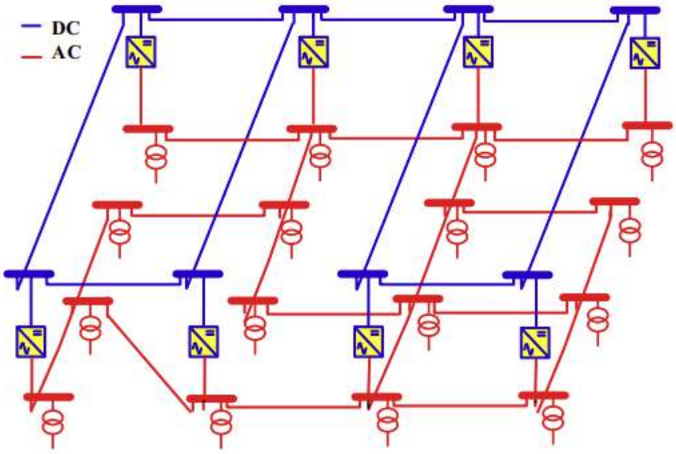

Figure 8: Example of design of a meshed multi-terminal DC [5]

HVDC Back-to-Back - Interconnecting asynchronous systems

High-voltage direct current (HVDC) transmission links are commonly used in power transmission networks to transfer large amounts of available power/energy over long distances, for example, transmitting electricity from large energy sources such as offshore wind power substations. Large-scale interconnection systems enable the optimization of power dispatch among multiple generation sources with different characteristics, enhance system reliability, and play a key role in effectively integrating the increasing share of variable renewable energy sources such as wind and solar.

HVDC systems are also used to interconnect power systems operating at different frequencies or at different phase angles (but the same frequency), commonly referred to as Back-to-Back (B2B) HVDC schemes. In a Back-to-Back HVDC configuration, the rectifier and inverter converters are installed at the same location, typically within the same station building. The two converters are connected via a very short DC link, so the length of the DC transmission line is minimal. Due to the short DC link, the DC voltage level is usually selected at a relatively low level, typically in the range of 50 kV to 150 kV, in order to reduce investment costs and insulation requirements for equipment. Locating all equipment at a single site facilitates operation, control, and maintenance, while enhancing system reliability. With these characteristics, Back-to-Back HVDC schemes are particularly suitable for interconnecting asynchronous power systems, especially in cross-border grid interconnection applications.

In the context of potential delays in several power sources in Northern Vietnam, EVN is proposing to increase electricity imports from China by constructing a 500 kV Back-to-Back (B2B) system with an import capacity of approximately 3,000 MW to Northern Vietnam, expected to be operational after 2030. The AC power from the Chinese side would be converted into DC and then converted back into AC synchronized with the Vietnamese power system. This arrangement allows power exchange between two systems operating at different frequencies.

Main components

HVDC line

The conductors of an HVDC transmission line may consist of overhead lines, cables, or a combination of both. When the installation of overhead lines is not feasible, HVDC cables (either underground or submarine) may be the preferred option or even the only viable solution.

Depending on the distance between the two converter stations, the HVDC transmission line can be one of the most significant components of the HVDC system in terms of total investment cost and power losses. Therefore, the selection of line conductors should be considered an integral part of the optimization process during the planning stage, taking into account total cost, rated power, and voltage level of the HVDC transmission system.

For overhead lines, key design considerations include corona effects (radio interference, power losses, and audible noise) as well as power losses. Corona effects are typically mitigated by increasing the equivalent radius of the conductor (also known as the geometric mean radius) and by increasing the number and/or cross-sectional area of sub-conductors in the bundled conductor. Power losses can be reduced by increasing the total conductor cross-sectional area. Both the number and cross-section of sub-conductors in a bundle have a significant impact on the overall cost of the HVDC transmission line. In general, the conductor cross-section should first be selected based on the rated current and the determined economic current density, and then verified against corona performance criteria and other constraints. Under high-altitude and high-voltage conditions, corona effects can be particularly significant and require special consideration.

The selection of HVDC cable type—whether underground land cable or submarine cable—requires simultaneous consideration of technical, economic, and environmental factors. Key requirements include insulation coordination with the converter station, load and overload capability, DC voltage level, HVDC link configuration, as well as installation conditions, protection measures, and transition points (between land cable and submarine cable or between cable and overhead line). In addition, specific factors such as water depth, landfall location, environmental impacts, and power reversal requirements also play an important role in the cable selection process.

HVDC superconducting cables have a design similar to HVAC superconducting cables. However, at present, HVDC superconducting cables remain largely at the prototype or demonstration project stage, and it is still unclear when the cost of this technology will decrease to a level that enables widespread commercial deployment[13].

HVDC converter station

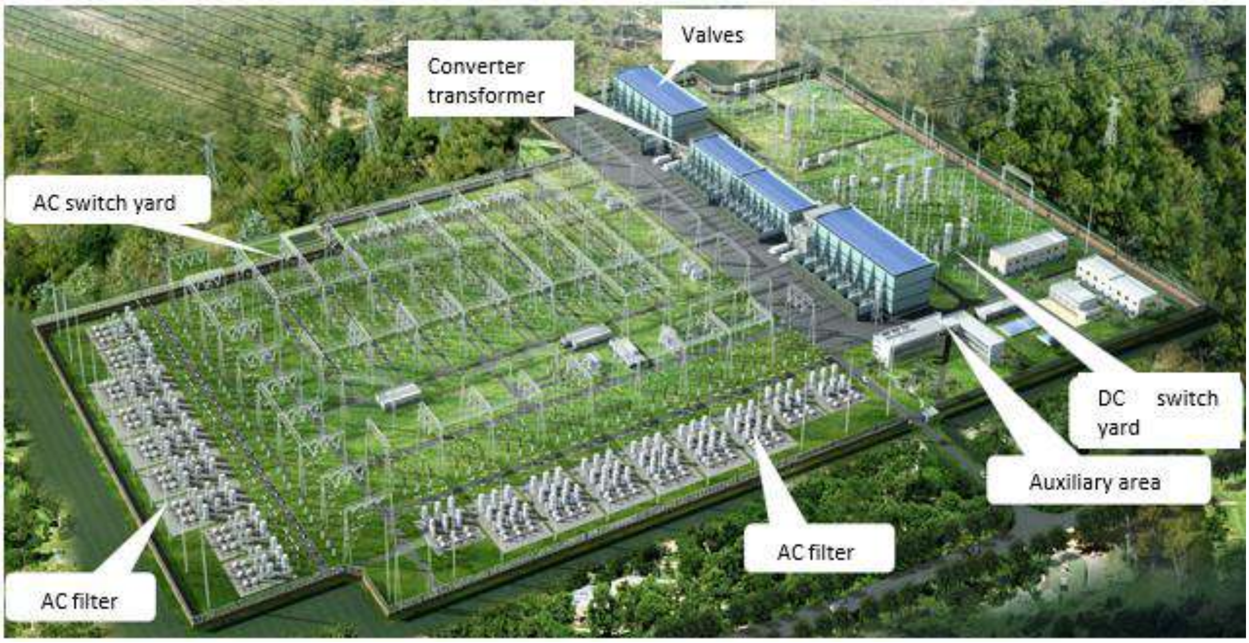

Figure 9: Basic configuration of an HVDC converter station (Source: GEDI)

a) Primary AC equipment

Primary AC equipment in an HVDC converter station serves as the direct interface between the AC power system and the converter station. This equipment includes busbar configurations, circuit breakers, disconnectors, current transformers, voltage transformers, and related protection components. Among them, the AC busbar configuration is the central element, determining the reliability, operational flexibility, and expandability of the station.

For large-capacity HVDC stations, the requirements for primary AC equipment are generally higher than those of conventional AC substations due to the large power exchange with the AC system, high short-

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[13] In October 2024, NKT collaborated with Stadtwerke München Infrastructure and other partners to inaugurate the world's longest superconducting cable test system, named SuperLink, in Munich, Germany. (https://www.nkt.dk/om-os/pressemeddelelser-events/nkt-paabegynder-test-af-verdens-laengste-superledende-kabel).

circuit currents at the point of connection, and the need for continuous operation and fault tolerance under the N-1 criterion. The scope of primary AC equipment in an HVDC converter station typically includes:

- AC busbars and switchyard equipment;
- Converter transformers;
- AC switching and isolation equipment;
- Primary measurement and protection equipment;
- AC-side compensation and filtering equipment.

b) Converter transformer

The converter transformer is the interface device between the AC system and the converter valves. It is one of the most critical and specialized pieces of equipment in the station.

Converter transformers differ from conventional AC transformers in several important aspects. In particular, an HVDC converter transformer must withstand insulation stress caused by DC voltage, in addition to the AC voltage stresses that a conventional power transformer is designed to handle. These two types of stresses differ in nature:

- AC voltage stress mainly exists in the insulating oil and is determined by the geometric design and the dielectric constant of the materials;

- In contrast, DC voltage stress depends on the resistivity of the insulating materials, whose values vary with operating conditions.

In addition, the converter transformer must be thermally designed to account for AC harmonic currents transmitted from the converter valves through the transformer to the AC harmonic filters.

Typically, the converter transformer is arranged with a grid-side winding connected in grounded star configuration, while the secondary windings are configured as floating star and delta. An on-load tap changer (OLTC) is usually installed on the grid-side winding, and its regulation range is generally wide to optimize converter design.

c) Converter valves

Converter valves perform the conversion from AC to DC or from DC to AC as required. Most HVDC converter valve groups are connected in a 12-pulse bridge configuration. A 12-pulse bridge consists of 12 valves, each of which may comprise many thyristors connected in series to achieve the rated DC voltage of the HVDC scheme [7].

Converter valves are the key distinguishing component between VSC-based and LCC-based HVDC systems. HVDC LCC (Line-Commutated Converter): Uses thyristors (controlled diodes). These devices can be turned on by a gate pulse but cannot be actively turned off. A thyristor valve requires the current through it to fall to zero in order to turn off. Therefore, the system is entirely dependent on the AC network voltage to perform commutation. If the AC grid is too weak or loses voltage, commutation failure can easily occur. HVDC VSC (Voltage Source Converter): Uses IGBTs (Insulated Gate Bipolar Transistors). These are fully controllable devices, allowing both turn-on and turn-off at any time as commanded by the control system. An IGBT valve can turn off without requiring the grid current to reach zero. This enables VSC to generate its own AC voltage independently of the AC grid, giving it black-start capability for restoring faulted power systems.

A thyristor/IGBT valve consists of many thyristors/IGBTs connected in series and/or parallel and operates as a single very large thyristor/IGBT. The valve must withstand hundreds of kilovolts in the blocking state. Since each individual thyristor/IGBT can withstand only a few kilovolts, many devices must be connected in series within one valve. Ensuring uniform voltage distribution across these series-connected devices is a major technical challenge.

d) AC filters

AC filters have two main purposes:

- To filter AC harmonics generated by the HVDC converter;

- To provide the reactive power required by the HVDC converter.

HVDC converter stations typically install shunt-connected and switchable AC filters, connected either directly to the converter valve busbar or to a dedicated filter busbar.

AC filters are automatically switched on/off by conventional AC circuit breakers to meet harmonic performance limits and reactive power requirements. Typically, an AC filter consists of a high-voltage capacitor bank connected in series with a medium-voltage circuit including air-core reactors, air-insulated components, resistors, and additional capacitor banks. These components are selected to ensure the required filter performance and proper rating.

The type and rating of the filter can be calculated based on system requirements (e.g., AC filtering performance, equivalent AC grid impedance, maximum switching voltage of the AC filter, etc.).

These performance requirements significantly influence the AC filter design, and thus directly affect the station footprint/layout and overall cost.

The design principles of system-side harmonic filters and associated breakers for both LCC and VSC HVDC systems are similar to those used in FACTS installations. High-pass filters, single-tuned, double-tuned, or triple-tuned filters may be used.

e) DC filters

The operation of converter valves generates harmonic voltage components at the DC terminals, meaning that sinusoidal AC harmonic components are superimposed on the DC voltage. These AC harmonic voltage components cause AC harmonic currents to flow in the DC circuit. The electromagnetic fields created by these harmonic currents may couple with nearby conductors, such as open-wire telecommunication systems, thereby inducing harmonic currents in other circuits.

In back-to-back schemes, these harmonics are confined within the valve hall through appropriate isolation systems; for cable-based schemes, the cable sheath usually provides harmonic shielding.

However, for DC transmission using overhead lines, DC filters may be required to limit harmonic currents flowing along the DC line if such harmonics adversely affect nearby systems (e.g., telephone lines).

DC filters have a physical structure similar to AC filters and are connected to the high-voltage level through a capacitor bank. Additional capacitors, together with reactors and resistors, are then connected in series with the high-voltage capacitor bank to achieve the desired tuning frequency and attenuation characteristics.

DC smoothing reactor

The DC smoothing reactor is a mandatory component in HVDC transmission schemes and forms part of the DC harmonic filtering system. It performs several functions, including:

- Reducing DC current ripple in overhead lines or transmission cables;

- Limiting the maximum potential fault current that may flow from the DC circuit into a fault at the converter valve, or into the valve due to a DC line/cable fault;

- Shifting DC-side resonances of the scheme to frequencies that are not multiples of the fundamental AC frequency.

The DC smoothing reactor is typically an air-core, air-insulated reactor (although oil-insulated iron-core reactors may also be used). In terms of layout, it is mainly installed at the high-voltage terminal of the HVDC converter valve for schemes with rated voltages ≤ 500 kV DC. For HVDC converters operating at higher voltages, it may be economically preferable to split the total DC inductance between the high-voltage and low-voltage terminals.

f) HVDC circuit breaker

The HVDC circuit breaker is used to interrupt direct current under both normal and fault conditions. A major challenge in interrupting DC current is the absence of a natural current zero crossing. Therefore, additional elements are required to create an artificial current zero, either by using special oscillation circuits in combination with mechanical breakers or by employing power electronic devices to perform current interruption. HVDC circuit breakers are essential components in meshed DC grids and multi-terminal DC links [1].

There are three main types of HVDC circuit breaker technologies:

- Mechanical Circuit Breakers (MCB): These use a passive resonant circuit consisting of a capacitor and an inductor connected in parallel with the main breaker contact. When the main contact begins to separate, an arc forms with a variable resistance (negative resistance characteristic). This interaction excites the LC circuit, generating an oscillating current with increasing amplitude. When the amplitude of the oscillating current equals the rated DC current, the total current through the main contact becomes zero, allowing the arc to be extinguished. This is an older technology, typically based on air-blast circuit breakers with multiple arc-extinguishing chambers, and it has a relatively long operating time.

- Solid-State Circuit Breakers (SS-CB): These use power electronic devices (such as IGBTs or MOSFETs) connected in series to interrupt the current. They are considered the fastest solution in terms of interruption speed. However, power losses during normal operation must be taken into account, and the initial investment cost is high.

- Hybrid Circuit Breakers (HCB): These combine ultra-fast mechanical disconnectors with controllable semiconductor devices. Upon receiving a trip command, the mechanical switch opens and generates a small arc voltage. This voltage is sufficient to force the current to commutate into the semiconductor branch (which has very low impedance when conducting). The current through the mechanical contact then decreases to zero. Subsequently, the semiconductor devices turn off to interrupt the current without producing an arc. Various configurations exist for this type of breaker. HCBs have low conduction losses but longer operating times compared to SS-CBs.

Input

AC power is converted into DC power through converters.

Output

DC power is converted into AC power through inverters.

Advantages/disadvantages

Challenges and characteristics for DC grids and AC/DC hybrid grids [5],[6]

Power flow control

In AC grids, flexible AC transmission system (FACTS) devices can be employed to adjust voltage levels by providing or consuming reactive power. In MTDC grids, the system state is different, since DC bus voltages are only characterized by their amplitude, and not by their phase-angle, and the transmission line impedances do not present any reactive component (inductive and capacitive reactance).

Devices of importance for dynamic behaviour (converter)

In a MTDC grid, the most vital component providing power exchange to and from the AC grid is the power electronics-based power converter. In comparison to synchronous generators, power converters have a time response that can be several orders of magnitude faster. Precise modelling of power converters and their controllers is, therefore, a key aspect for assessment of the MTDC grid’s dynamic behaviour.

Stability via VSC controllers

Stability analysis for an MTDC grid, which only relies on the DC bus voltage magnitudes, has to be approached in a different way than in AC power systems. In this sense, detailed models for the MTDC grid, the power converters’ controllers and the AC network, should be elaborated and systematic analyses should be carried out to define the ranges of the VSC controllers in order to ensure dynamic voltage stability at the MTDC grid and to know how fast the VSC controllers and protections should react in order to avoid a collapse of the MTDC grid. VSC converter systems are preferred in designing a MTDC grid[14].

Protection devices and HVDC breaker

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[14] There are several multi-terminal DC networks (MTDC) in operation with LCC converters, but it is clearly simpler to make MTDC with VSC converters because one does not have to change polarity to change the power direction.

The development of appropriate protection devices and strategies for MTDC grids is a challenging issue, and the lack of efficient protection strategies is a constraint on the pace of development of MTDC technology.

Components & enablers [6]

The most important components:

- LCCs with capacities of approx. 4 – 8 GW per circuit, and continuing developments towards 2050
- VSCs with ratings in the range of 1 – 3 GW per circuit, and continuing developments towards 2050
- HVDC Circuit breakers
- HVDC Gas insulated switchgears

Enablers are:

- Advanced operational coordination between TSOs
- Advanced modelling technique of hybrid systems (AC/DC): dynamics, stability
- Tailored fault clearing strategies to the specific HVDC/HVAC grid characteristics

Advantages & field of application [6]

The choice between an extension of a grid in AC or DC depends on a variety of technical, economic and environmental factors. The profitability threshold between the two types of current systems has varied over time depending on the use cases. The first building of a DC system was registered in 1954 in Sweden when the island of Gotland was connected to the mainland via a 98 km long sea cable.

With the increasing need to integrate remote large-scale renewables and the growing share of distributed DC connected energy resources, DC transmission will become more relevant, and its integration within the current AC system will contribute in several ways to achieving a cost-efficient energy transition.

Major advantages of the integration of DC systems in AC systems [6]:

Benefits of integrating DC transmission into Vietnam’s power grid:

- Meeting long-distance transmission needs: Major load centres such as Hanoi and Ho Chi Minh City are often located far from large power sources (Northwest hydropower, wind and solar in the South Central and Central Highlands). DC systems enable stable and efficient transmission of large amounts of electricity over long distances.
- Reducing right-of-way requirements: Particularly in the Central region, where terrain is narrow, land is limited, and land clearance is increasingly challenging, DC technology helps reduce the width of transmission corridors, saving land and minimizing social impacts.
- Lowering transmission losses: For long-distance transmission, DC grids have lower losses compared to AC, enhancing operational efficiency and reducing system costs.
- Facilitating renewable energy integration: Offshore wind and remote solar sources can be connected directly to the DC system, avoiding overloads on regional AC grids and maximizing renewable energy utilization.
- Strengthening regional grid interconnections: DC technology allows flexible connections with neighbouring power systems such as Laos, China, and Cambodia, enabling electricity import during shortages and export during surpluses, contributing to energy security and regional integration.

Research and development are being accelerated in the field to overcome the technical and regulatory barriers to operate and control MTDC system and integrate them in meshed AC systems. Such integration will combine the benefits of AC and DC technologies and open the door to new devices and systems, such as HVDC circuit breakers, HVDC gas insulated switchgears and flexible DC transmission system devices that can bring benefits to the security, reliability, performance, and economics of a DC grid system.

Concepts such as the “North Sea Wind Power Hub” already show advanced DC grid layouts complementing the AC onshore system. The Mediterranean Grid (“Med Grid”) idea is already linking European, North African and Middle Eastern areas around the Mediterranean area.

Space requirement

Currently, Vietnam does not yet have regulations on safety corridors for HVDC transmission lines. Based on China's experience, the right-of-way corridor for a bipolar HVDC system is comparable to that of a three-phase HVAC system. However, the power transfer capacity of HVDC systems is higher than that of HVAC, so it can be considered that HVDC uses less space per unit of power.

According to [8], the estimated land area for an LCC converter station (500 MW) is about 27 hectares, while a VSC converter station (500 MW) requires about 20.7 hectares. The land area of converter stations typically depends on factors such as capacity scale and the number of line bays, with land-use intensity ranging from approximately 0.004 to 0.009 ha/MW for LCC technology. The land footprint of VSC stations is generally about 40–80% smaller than that of LCC stations.

Environment

The environmental impacts of DC transmission systems mainly include

- Impact on landscape – Overhead transmission lines are often considered to negatively affect the aesthetics of the surrounding landscape.
- The long length of transmission lines leads to large land occupation, resulting in challenges related to compensation, site clearance, and potential impacts on ecosystems.
- HVDC stations use high-power electronic components, require cooling systems (water or air), and may generate significant noise from transformers and filters.
- HVDC generates a static electric field (similar to the Earth's magnetic field), unlike the varying fields of HVAC. Although it raises fewer health concerns, it may interfere with compasses or precise navigation devices near the lines.
- If the system operates in monopolar mode and uses earth/sea return, it may cause corrosion of buried metallic pipelines or interfere with submarine communication cables.

However, HVDC transmission systems are considered more environmentally friendly than AC transmission systems due to reduced corridor requirements and minimized energy losses.

Research and development

Currently, the entire power grid is operated using alternating current (AC) technology. Therefore, exploring the development and application of high-voltage direct current (HVDC) transmission technology opens up many new research directions related to system design, construction, installation, and operation. At the same time, the deployment of this technology also creates a need for research and improvement of standards, technical regulations, and technical guidelines for each stage of implementation, as well as the development of appropriately skilled human resources to meet the requirements of future HVDC transmission systems.

In addition, it is necessary to study the capability to master the technology and operate cross-border transmission lines, especially Back-to-Back systems.

The lack of effective protection solutions remains a factor limiting the development speed of MTDC technology. To address this issue, many manufacturers and research groups are focusing on developing DC circuit breakers to enable early standardization and commercialization.

Reference international standard

The framework of standards and guidelines applicable to HVDC systems is not defined by a single standard or guideline, but rather by a combination of multiple standards and guidance documents. The most commonly used international standard systems today include IEC , IEEE , and CIGRE . Throughout the lifecycle of an HVDC project—from planning to operation—no single system of standards and guidelines can comprehensively cover all technical aspects. The current international standard system for HVDC has covered most of the equipment, main components, and technologies of HVDC systems. For LCC technology, standards such as IEC 63127, IEC 63179-1, and IEC 60071-12 focus on system design guidance, planning, and insulation coordination specific to converter stations. Meanwhile, VSC technology is standardized through IEC 62747 on terminology, IEC 62543 for equipment selection, and IEC 63411 for offshore wind integration. The design and operation of hybrid LCC/VSC systems are guided in CIGRE TB 950. For converter valves, standards/guidelines such as IEC 60700, IEC 62501, and CIGRE TB 136 provide stringent requirements for testing thyristor valves, VSC valves, as well as fire and explosion safety for valve halls. For transmission lines and cable systems, standards/guidelines such as IEC 62895, IEC 62681, and CIGRE TB 852 provide a technical framework for design, electromagnetic performance assessment, and testing procedures for insulated cables, with voltage levels up to 800 kV. For station equipment, including transformers and filters, standards such as IEC 61378, IEC 62001, and CIGRE TB 223 set out design and operational requirements to ensure efficient voltage conversion and harmonic control within the system. For control, protection, and insulation systems, standards such as IEC 61850-90-14, IEC 63368, and IEC 62772 specify communication architectures, protection schemes, and insulation characteristics, ensuring data synchronization and overall operational safety of HVDC stations.

Regarding submarine cables, the framework differs between AC and DC applications. IEC 63026 specifies requirements for fixed submarine power cables AC with extruded insulation, including electrical, material, component, and mechanical tests specific to marine environments, for voltage levels ranging from 6 kV to 60 kV. This standard has been adopted in Vietnam as TCVN 14467:2025. For submarine cables with voltage levels above 60 kV, reference is typically made to land cable standards (IEC 60840 for voltage levels from 30 kV to 150 kV, and IEC 62067 for voltage levels from 150 kV to 500 kV). However, these standards clearly state that for special applications such as submarine cables, standard test requirements may need to be adapted or supplemented with specific test conditions to suit the underwater environment. For higher-voltage HVDC marine applications, CIGRE TB 852 and CIGRE TB 853 are important references, providing recommendations for testing extruded and lapped HVDC cable systems, respectively, up to 800 kV, including submarine applications.

Examples of current projects

500 kV Back-to-Back interconnection system for importing electricity from China (DC corridor between two synchronous areas)

Amid concerns over delays in the commissioning of several power sources in northern Vietnam, EVN is proposing to increase electricity imports from China by constructing a 500 kV Back-to-Back (B2B) system, with an expected import capacity of approximately 3,000 MW to the 500 kV Lao Cai substation.

Expected commissioning timeline: Estimated after 2030.

Expected investment scope:

- On the Chinese side:
  - Construction of a 500 kV Back-to-Back station.
  - A 500 kV transmission line from Yunnan to the Back-to-Back station and up to the border.
- On the Vietnamese side:
  - Construction of a double-circuit 500 kV transmission line from the border interconnection point to the 500 kV Lao Cai substation (approximately 40 km in length).

Viking link (DC corridor between two synchronous areas)

Viking Link [9] is a new high voltage direct current (DC) electricity interconnector between the substation Revsing in southern Jutland, Denmark, and Bicker Fen in Lincolnshire, Great Britain. Its capacity is 1400 MW:

- The interconnector went into operation in December 2023.
- Viking Link is developed by Energinet and the British National Grid, via National Grid Viking Link Ltd. and other subsidiaries.

The connection is composed of the following components:

North Sea:

- 625 km high voltage direct current (HVDC) submarine cables between Great Britain and Denmark. The cables are buried in the seabed.

Denmark:

- A pair of onshore underground high voltage DC cables from the west coast of Jutland to the existing 400 kV substation Revsing near Vejen
- Converter station (VSC technology) in Revsing near Vejen to convert electricity between DC and AC
- New equipment within the existing 400 kV substation at Revsing

Great Britain:

- A pair of onshore underground high voltage DC cables (66.5 km) from the coast in Great Britain to a converter station
- A converter station (VSC technology) to convert electricity between direct current (DC) and alternating current (AC)
- High voltage alternating current (AC) underground cables from the converter station to the existing National Grid substation at Bicker Fen in Lincolnshire
- New equipment within the existing substation

Changji–Guquan HVDC System [10]

As of the end of 2025, China had more than 20 HVDC systems nationwide, with a total HVDC transmission line length of approximately 60,000 km. Although a latecomer in the development of high-voltage and ultra-high-voltage direct current transmission technologies, China has sought to become a key actor in shaping international standards for HVDC transmission. At present, China is leveraging this process of global coordination to internationalize its indigenous HVDC technologies, particularly by promoting HVDC standards. China's active participation in international standardization organizations has enabled Chinese enterprises to embed national priorities into international HVDC standards. At the same time, these enterprises are working to increase the likelihood of achieving global consensus on technical parameters and market access requirements in ways that are favorable to their technologies.

The Changji–Guquan HVDC system (Changji–Guquan) is one of China's most important ultra-high-voltage direct current (UHVDC) transmission projects, holding world records for operating voltage, transmission capacity, and transmission distance as of 2026.

Key technical parameters of the system:

- Operating voltage: ±1,100 kV, the highest voltage level in the world to date.
- Transmission capacity: 12 GW.
- Transmission line length: approximately 3,300 km, crossing six provinces and autonomous regions, including Xinjiang, Gansu, Ningxia, Shaanxi, Henan, and Anhui.
- Total investment: approximately GBP 4.7 billion (equivalent to USD 5.9 billion).
- Construction commenced in January 2016; the system was commissioned in December 2018.
- Major equipment suppliers: ABB – converter transformers, HVDC valves, bushings, on-load tap changers, DC circuit breakers, and capacitors (contract value of approximately USD 300 million); Siemens – 587 MVA transformers for the Guquan converter station; TBEA (China) – 607.5 MVA converter transformers for the Changji converter station.

Strategic significance of the project:

- Enhancing energy security for the most densely populated regions in eastern China by transmitting electricity generated in the sparsely populated but renewable-energy-rich northwest.
- The project is estimated to reduce coal consumption at power plants in eastern China by approximately 38 million tonnes per year.
- The system is capable of supplying power equivalent to eight 500 kV AC transmission lines and two 1,000 kV AC transmission lines.
- Demonstrating China's technological self-reliance in HVDC, with localization of core equipment reaching 99.9%.

COBRAcable: Interconnector of Denmark - Netherlands

In September 2019 the first interconnector between Denmark and the Netherlands was commissioned. The interconnector has a capacity corresponding to the annual electricity consumption by approx. 700,000 households. The purpose of the COBRAcable is to improve the cohesion of the European transmission grids by increasing the exchange of excess wind power to neighbouring countries and strengthening the electrical infrastructure, the security of supply and the European electricity market.

The connection contributes largely to the introduction of renewable power production in that both countries are able to manage much more sustainable production, i.e. buy and sell wind power and solar power across borders whenever there is a surplus situation in either one of the countries. This increases the value of sustainable energy. At the same time, the connection ensures a high level of security of electricity supply, as more and more wind energy flows into the systems “as the wind blows”.

The connection is designed to meet future requirements by presenting the opportunity for future offshore wind farms in the North Sea to be connected to the COBRAcable. Furthermore, the cable can be part of a future interconnected offshore electricity grid between the countries bordering the North Sea.

Technical description

The COBRAcable consists of two parallel, approx. 300km long, DC submarine cables linking western Denmark and the Netherlands together. The project also comprises approx. 20 km of onshore cable. The cables are connected to converter stations built in Endrup, east of Esbjerg, Denmark and Eemshaven in the Netherlands, respectively.

The new Voltage Source Converter technology used for the project, provides the option for connecting offshore wind farms to the cable. Hence, the COBRAcable can be the first stepping stone towards the establishment of an actual offshore grid in the North Sea, capable of unpinning the expansion of wind power and strengthening the European electricity transmission grids.

The installations

The converter stations

The converter stations in Endrup and Eemshaven connect the 400-kV (kiloVolt) AC grid to the DC COBRAcable.

The converter stations transform the AC of the national grids to DC and vice versa.

The COBRAcable is built with the latest converter technology, the VSC – Voltage Source Converter – and not the well-known LCC technology – Line Commutated Converter – used in most of Energinet’s other DC connections.

The VSC technology is based on IGBTs – insulated gate bipolar transistors – whereas the LCC technology is based on the use of thyristors. The VSC technology offers several advantages:

- As opposed to LCC, the VSC technology offers “black start capability”, i.e. the DC connection can be used to start up the Danish grid (area DK1) in case of a total blackout.
- One of the advantages of the VSC technology is that it enables control of reactive power and hence contributes to controlling the voltage level in the AC grid. This advantage makes the VSC technology economically attractive in connection with the development of renewable energy resources as operating the large power plants is not feasible in situations with sufficient wind power.

In the past, VSCs had so large electrical losses that the technology was not competitive compared to the LCC technology. However, the technology has improved. The losses in Interconnectors based on VSC technology today are only marginally larger than with the LCC technology. So, with this and other operating advantages, the VSC technology is an attractive alternative, and the VSC technology is seen as the future technology in HVDC.

The COBRAcable project includes a research project with two PhD students who work on developing a multi-terminal HVDC concept in case it becomes feasible to connect one or more offshore wind farms to the COBRAcable.

The converter station in Denmark

The converter station in Denmark is built close to the existing transformer station at Endrup, east of the town of Esbjerg. Offshore wind farms Horns Rev 2 and 3 are also connected here.

The converter station is an extension of the existing HVAC substation and includes a 2-breaker converter that connects the COBRAcable to the Danish high-voltage grid:

- Converter hall where the cables are connected and the VSC equipment is installed. The building's total length is 121 meters and its height 19.5 meters. Architects have been involved in the design to ensure that the structure blends into the landscape.
- Extension of the existing HVAC substation to connect the converter to the existing HV grid
- A new HVAC yard for switchgear, transformers, cooling plant etc.
- A building for the converter's controls, auxiliary supply, cooling pumps etc.
- A building for spare parts and maintenance equipment.

The cables

The total cable route is 329 km of which 307 km are offshore and 22 km are onshore. Two cables are installed in parallel making the total length of cables 658 km. The cable is a 320-kV PEX DC cable with a 2,500-mm^2 aluminium conductor. The submarine cables will be installed as bundled, whereas the onshore part will be installed in cable ducts at a distance of 70 cm.

Prediction of performance and cost

The methodology for forecasting the cost of DC transmission technology is similar to that of AC transmission technology. The evaluation of costs and operational performance is based on the following main sources of information:

1. Institute of Energy, Study on the application of HVDC transmission technology in Vietnam, 2026 [11].
2. DEA&IE, Analysis of HVDC for PDP 8 Vietnam, 2020 [12].

In addition, domestic experts also received technical support and consultations from HVDC system suppliers such as Hitachi (formerly ABB) and Sumitomo.

Economic data for DC lines

The datasheet for high-voltage direct current (HVDC) transmission technology is based on international references and informal technical exchanges with equipment suppliers, since Vietnam has not yet conducted comprehensive studies or implemented specific projects.

Economic data for DC onshore and offshore cables

The table below summarizes the results of the cost projections for selected OH-lines. Note that in general there is high variation in prices for each category. The prices therefore have a high uncertainty.

Table 12: The results of the cost projections for selected OH-lines

OH-line	Unit	2025	2030	2040	2050
Investment, OH lines DC 500 kV DC	mill USD/km	1.14	1.14	1.03	0.91
Investment, OH lines DC 800 kV DC	mill USD/km	1.83	1.83	1.65	1.46

Table below summarizes the results of the cost projections for selected cables. Note that in general there is high variation in prices for each category. The prices therefore have a high uncertainty.

Table 13: The results of the cost projections for selected cables

Cable	Unit	2025	2030	2040	2050
DC underground cables, 1500-2000 MW capacity	mill USD/km	16.60	16.60	14.94	13.28

DC sea cables, 1500-2000 MW capacity	mill USD/km	34.60	34.60	31.14	27.68

Economic data for DC converter station

The datasheet for high-voltage direct current (HVDC) transmission technology is based on international references and informal technical exchanges with equipment suppliers, since Vietnam has not yet conducted comprehensive studies or implemented specific projects.

Cost forecast for DC converter station

Table 14 summarizes the cost forecast for selected DC converter station.

Table 14: The results of the cost projections for selected substations

	Unit	2025	2030	2040	2050
DC LCC onshore substation, 1000-1250 MW capacity	Mill USD/MW	0.11	0.11	0.10	0.09
DC VSC onshore substation, 1000-1250 MW capacity	Mill USD/MW	0.17	0.17	0.15	0.14
DC offshore substation, incl. platform, 1500-2000 MW capacity	Mill USD/MW	0.45	0.45	0.40	0.36

Economic data, O&M

The annual costs of operating and maintaining the transmission system components vary due to system design, materials, climate, age etc. Often the costs are assumed to be a percentage per year of the investment cost (CAPEX). For all assets – OH-lines, cables, substations, transformers and compensation - the fixed O&M values are set as 2% (of CAPEX per year). It can be argued that O&M costs would not increase with the same rate as an abrupt CAPEX increase. However, for the sake of simplicity the percentages are kept unchanged from 2025-2050.

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[12] DEA and IE, »Analysis of HVDC for PDP 8 Vietnam«, 2020.

Data sheet

Overhead lines DC (double circuit)													
Parameter	**Unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
								Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data													
Energy losses, OH lines DC at rated power	%/100 km	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.10%	0.50%	0.10%	0.50%		2, 3, 5
Technical life time	years	50	50	50	50	50	50	50	70	50	70		1
Typical load factor	%	80%	80%	80%	80%	80%	80%	70%	90%	70%	90%		
Construction time	years	2	2	2	2	2	2	1	3	1	3		1
Economic data													
Investment, OH lines 500 kV DC	mill USD/km	1.14	1.14	1.07	1.03	0.96	0.91	0.80	1.49	0.64	1.19	A, B, C, D, E, G	4, 6, 7
Investment, OH lines 800 kV DC	mill USD/km	1.83	1.83	1.72	1.65	1.54	1.46	1.28	2.38	1.02	1.90	A, B, C, D, E, F, G	4, 6, 7
Investments, installation	%	30%	30%	30%	30%	30%	30%	-	-	-	-		2, 4
Investments, materials	%	57%	57%	57%	57%	57%	57%	-	-	-	-		2, 4
Additional costs	%	13%	13%	13%	13%	13%	13%	-	-	-	-		2, 4
Fixed O&M	% of CAPEX/year	2%	2%	2%	2%	2%	2%	-	-	-	-		2, 4
Variable O&M	USD/MWh/km	-	-	-	-	-	-	-	-	-	-		

Notes:

A	Based on the investment cost estimate for OH line 500 kV AC, conductor size ACSR4x600 (double circuit) in cost per km. and applying a DC to AC cost ratio of 80 % (MEUR/km) taken from [7], where they estimate comparable AC OH lines to cost 2.50 MEUR/km and DC OH lines to cost 2.00 MEUR/km (= 80 %).
B	The investment cost represents line-only overhead transmission costs and excludes HVDC terminal/converter, compensation, support and resettlement costs, interest during construction, initial working capital, contingency costs, and VAT.
C	Unit cost is corresponding to installation in weak soil conditions and routes passing through forests.
D	Lower and upper uncertainties are minus/plus 30%.
E	Prices are assumed to decrease linearly from 2030 to 2050 with 20%.
F	Based on the 500 kV DC line-only estimate using an engineering uplift of 1.6 (1.4 - 1.8) on cost per km to reflect the heavier line class of 800 kV overhead lines. This uplift is informed by voltage-class design differences from [8] and should be treated as an assumption.
G	The Danish Technology Catalogue expresses investment costs in USD/km/MW. However, in Vietnam, transmission line investment costs are typically calculated in USD/km. To convert between these units, the cost in USD/km can be divided by the rated transmission capacity of the line to obtain the cost in USD/km/MW.

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4 EVN 2023, Unit Capital Investment for the Construction of Power Grid Projects at Voltage Levels from 110kV to 500kV

5 Technical parameters from catalogue of overhead conductors

6 Netzentwicklungsplan Strom (German TSOs), version 2021

7 MISO 2024, Transmission Cost Estimation Guide for MTEP24

Cables DC													
Parameter	**Unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
								Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data													
Energy losses, cables DC at rated power	%/100 km	0.30%	0.30%	0.30%	0.30%	0.30%	0.30%	0.10%	1.00%	0.10%	1.00%		1
Technical life time	years	40	40	40	40	40	40	25	40	25	40		2
Typical load factor	%	80%	80%	80%	80%	80%	80%	70%	90%	70%	90%		
Construction time	years	2	2	2	2	2	2	-	-	-	-		2
Economic data													
DC underground cables, 1500-2000 MW capacity	mill USD/km	16.6	16.6	15.78	14.94	14.12	13.28	11.62	21.58	9.3	17.26	A, B, C, D	2, 3
DC sea cables, 1500-2000 MW capacity	mill USD/km	34.6	34.6	32.88	31.14	29.42	27.68	24.22	44.98	19.38	35.98	A, B, C, D	2, 3
Investments, installation	%	30%	30%	30%	30%	30%	30%	-	-	-	-		2, 3
Investments, materials	%	57%	57%	57%	57%	57%	57%	-	-	-	-		2, 3
Additional costs	%	13%	13%	13%	13%	13%	13%	-	-	-	-		2, 3
Fixed O&M	% of CAPEX/year	2%	2%	2%	2%	2%	2%	-	-	-	-		2, 3
Variable O&M	USD/MWh/km	-	-	-	-	-	-	-	-	-	-		

Notes:

A The investment cost excludes compensation, support and resettlement costs, interest during construction, initial working capital, contingency costs, and VAT.

B Prices assumed to decrease linearly from 2030 to 2050 with 20%.

C Lower and upper uncertainties are minus/plus 30%.

D The Danish Technology Catalogue expresses investment costs in USD/km/MW. However, in Vietnam, transmission line investment costs are typically calculated in USD/km. To convert between these units, the cost in USD/km can be divided by the rated transmission capacity of the line to obtain the cost in USD/km/MW.

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Substations DC, Onshore and Offshore

Parameter	Unit	2025	2030	2035	2040	2045	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
								Lower	Upper	Lower	Upper		
Energy/technical data													
Energy losses, DC LCC substation	%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.7%	1.6%	0.7%	1.6%		4, 5
Energy losses, DC VSC substation	%	1%	1%	1%	1%	1%	1%	1%	2%	1%	2%		4, 5
Technical life time	years	40	40	40	40	40	40	20	40	20	40		2
Typical load factor	%	80%	80%	80%	80%	80%	80%	70%	90%	70%	90%		
Construction time	years	2	2	2	2	2	2	-	-	-	-	A	
Economic data													
DC LCC onshore substation, 1000-1250 MW capacity	Mill USD/MW	0.11	0.11	0.10	0.10	0.09	0.09	0.08	0.14	0.06	0.11	B, C, D, E	3
DC VSC onshore substation, 1000-1250 MW capacity	Mill USD/MW	0.17	0.17	0.16	0.15	0.14	0.14	0.12	0.22	0.10	0.18	B, C, D, E	3
DC offshore substation, incl. platform, 1500-2000 MW capacity	Mill USD/MW	0.45	0.45	0.42	0.40	0.38	0.36	0.31	0.58	0.25	0.46	B, C, D, E	1, 2
Investments, installation	%	27%	27%	27%	27%	27%	27%	-	-	-	-		1, 2
Investments, materials	%	60%	60%	60%	60%	60%	60%	-	-	-	-		1, 2
Additional costs	%	13%	13%	13%	13%	13%	13%	-	-	-	-		1, 2
Fixed O&M	% of CAPEX/year	2%	2%	2%	2%	2%	2%	-	-	-	-		
Variable O&M	USD/MWh/km	-	-	-	-	-	-	-	-	-	-		

Notes:

A Project specific, depends on size and location of station.
B Estimates, project specific, depends on size and location of station. DC substation includes converter, converter transformers, AC switchgear and busbars, harmonic filters, lightning towers, ancillary plant etc.
C The investment cost excludes compensation, support and resettlement costs, interest during construction, initial working capital, contingency costs, and VAT.
D Prices assumed to decrease linearly from 2030 to 2050 with 20%.
E Lower and upper uncertainties are minus/plus 30%.

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2. TRANSPORTATION OF GAS AND LIQUID FUEL

General introduction of transportation of gas and liquid fuel

Purpose and scope

The gas and liquid fuel transportation technologies considered include:

1. Transportation of gas and liquid fuel by pipeline.
2. Transportation of gas and liquid fuel by ship.

These subsections are preceded with this introduction section that includes:

1. Description of the different types of fuels and their key properties (Sections *Properties* & *Short fluid description and Grade*)
2. Grouping fuels into (Section *Transport form – chemical phase*):
    - Liquid fuels (LHC)
    - Fuels that are liquefied @ 20 bar (L20)
    - Fuels that require extreme cooling to liquify (H_2NG)

    To avoid having to treat each fuel separately, the above three fuel groups have been defined. These groups are used to identify which transport form/phase is possible/optimal and thereby which elements that are needed in the transport chain.

3. Advantages and disadvantages of different transport forms (i.e. pipeline, truck, train and ships) (Section *Transport unit – pipeline, truck, train or ship*)
4. Material of construction, i.e. steel grade needed for handling the different types of fuels (Section
5. *Figure 18:* Ship transporting LNG from South to North
6. Material of construction)
7. Safety issues (Section *Safety*)
8. Overall transport chain (Section *Transport chain - logistic and infrastructure*) giving an overview of the elements that must be included in the entire transport chain.
9. Energy loss - overview of different type of energy losses and how they can be predicted (Section *Energy losses*).
10. Possible elements of the transport chain:
    - Conversion to/from hydrogen carrier (Section *Conversion to/from carrier (LOHC)*) (only for H_2)
    - Conversion to liquid phase by cooling (Section *Convert to liquid phase by cooling*)
    - Compressor (Section

    Figure 24: Energy loss associated with liquefaction of H_2 [15]

    - Compressor)
    - Pumps (Section *Pumps*)
    - Fiscal metering (Section *Fiscal metering stations*)
    - Storage tanks (Section *Storage tanks*)

    These sections include losses and costs for the different elements.

11. Examples (Section *Examples - full transportation chain*) of calculating loss and cost for the entire transport chain.

Properties

Key properties

This chapter list key chemical properties for fuels and some LOHC. The purpose is for later reference.

This catalogue aims to lump components into fuel groups that are treated together. Therefore, properties for other fluids than the H_2, NH_3, DME and LOHC have been included.

The following properties are given:

1. **Energy density:** The energy density listed is per mass. This can be converted to energy density per volume by multiplying with the density which is given too. The mass- and volume-based energy density is plotted in Figure 10.
2. **Freezing point and boiling point/distillation curve:** The freezing point gives the solidification point while the boiling point/distillation curve give the point/range where it vaporizes. For single components (i.e. H_2, NH_3, MeOH, etc.), freezing and boiling points are single point, while for mixtures (LPG, gasoline, jet fuel, etc.) it's in ranges. These properties give the chemical phase (solid, liquid, gas) that a given fuel will take at ambient pressure (1.025 bar).
3. **Flash point, autoignition point and flammability/explosion limit:** These properties are ignition and safety related properties. Flash and autoignition point give the lowest temperature at which it ignites with and without an ignition source. The explosion limit gives the fuel concentration range in air where it will burn/explode in the presence of an ignition source.

Energy density

The energy density for various fuels is shown in Figure 10 below.

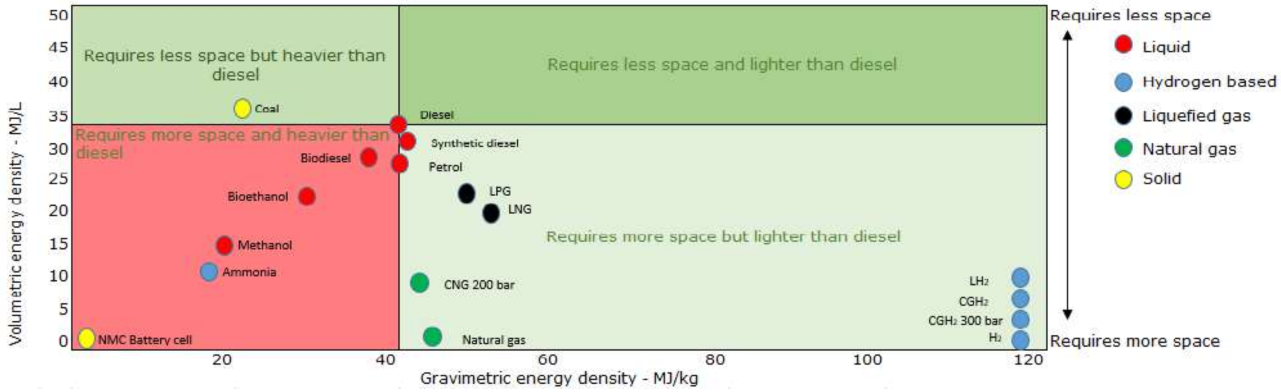

Figure 10: Energy density for various fuels

Phase curve

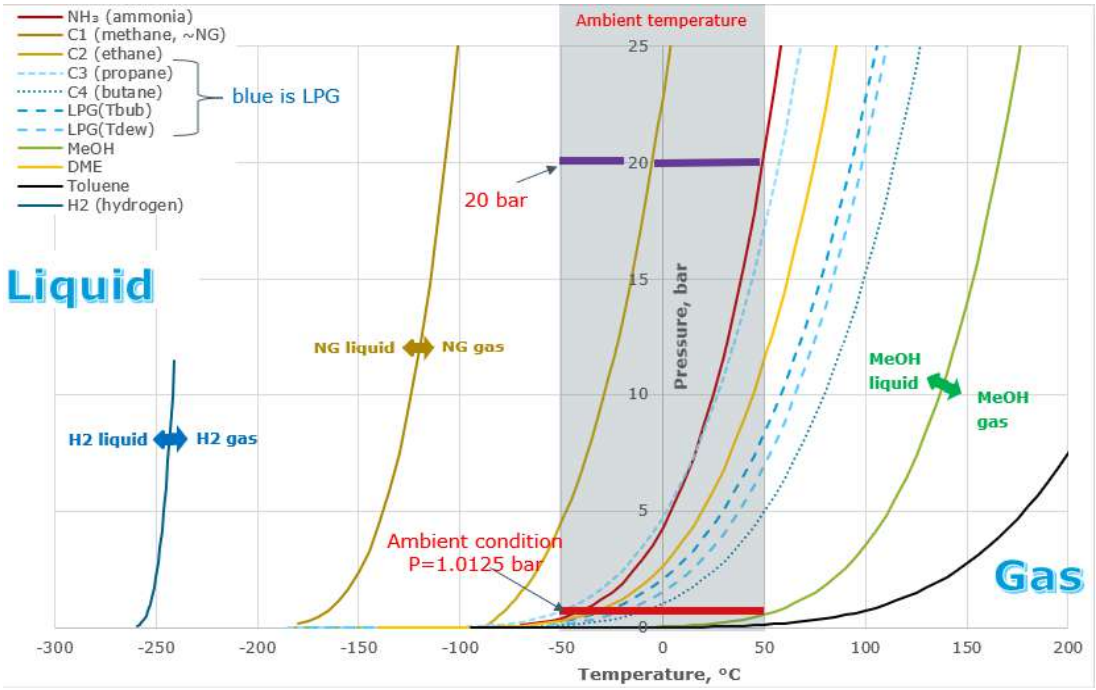

Figure 11: Phase curve for various fuels. Toluene is representative for LOHC which all are liquid at ambient condition. All hydrocarbon mixtures above C5 and all alcohols are below the MeOH curve

In Figure 11 the gas-liquid phase curve is represented for various fuels. Thus, the fuel is liquid on the left-hand side of the curve and gas on the right-hand side. The red line represents ambient condition (pressure is 1.025 bar and temperature is between -50 °C and +50 °C). This red line express which phase the fluid is if not exposed to any cooling or pressurization. At 20 bar (the purple line) the majority of fuels (all except for hydrogen, methane and ethane) are liquids.

Short fluid description and Grade

Hydrogen (H_2)

Hydrogen is lighter than air, highly flammable, very easily ignited, does not cool when expanded, and has so small molecular size that leakage and even penetration into the surrounding material is a key design issue.

Hydrogen fuel grades – key requirements to hydrogen when used as fuel for PEM fuel cells for road vehicles (ISO 14687, SAE J2719):

1. >99.97 %
2. < 5 ppm H_20, < 5 ppm O_2
3. Max requirements to several other impurities

Ammonia (NH_3)

Ammonia is a toxic, corrosive, less flammable gas with a strong characteristic odor. Ammonia is lighter than air but because of its tremendous affinity for water, it reacts immediately with the humidity limiting the dispersion in the environment. Is not a greenhouse gas.

Typical product specification [1]:

1. >99.5 wt % NH_3
2. 0.2-0.5 wt % Water
3. max 5 ppm Oil

Refrigerant grade ammonia:

1. >99.95 wt % NH_3
2. < 33 ppm H_2O
3. < 2 ppm Oil

Ammonia is still not approved as fuel, thus no fuel grade requirement exists yet.

Dimethyl ether (DME)

Dimethyl ether (DME, CH_3OCH_3) is colorless, non-toxic and highly flammable.

Typical product specification:

- 99.7 DME
- Rest is MeOH

Transport form – chemical phase

Within this catalogue, fuels are divided into three groups.

Table 15: Transport groups, which fuel belong to each group, possible transport form/phase and possible transport options

Group	Description	Include	Transport form	Transport options		
				Pipeline	Truck/ train	Ship
1 LHC	Liquid @ ambient condition (see Liquid fuels (LHC))	HC where CNO≥5 All alcohols All LOHC	Liquid P=few bars, T=Amb.	yes	yes	yes

2 L20	Liquid @ P=20 bar (see Liquid at ≥ 20 bar (L20) - NH3, DME and LPG)	NH_3 LPG DME (Ethane)	Pressurized Liquid P=10-30 bar, T=Amb.	yes	yes	yes
			Cooled liquid P=few bars, T~ (-25)-(-45) °C	no	yes	yes
3 H_2NG	Require extreme cooling to liquify (see H2 and NG)	H_2 Methane/NG	Pressurized gas NG: P=60-80 bar, T=Amb H_2: P=60-140 bar, T=Amb	yes	yes	no
			Cooled liquid[15] NG: P=few bars, T~-163°C H_2: P=few bars, T~-253°C	no	yes	yes
			Carrier (only H_2) P=few bars, T=Amb.	yes	yes	yes

Group 1 (LHC) is liquid at ambient condition. Group 2 and 3 fuels are converted into the more energy dense transport form either via pressurization, cooling or reaction with a carrier (latter only relevant for H_2). The advantages and disadvantages for each of these packing methods are listed in Table below.

Table 16: Advantages and disadvantages for different methods of converting group 2+3 into more energy dense transport form.

	Pressurized	Cooled	Carrier (only H_2)
Advantages	1. Low compression loss 2. Low transportation loss	1. High volumetric energy density compared with compressed gas	1. Higher volumetric energy density compared with both CH_2 and LH_2 2. Stored at ambient condition 3. Existing infrastructure can be used 4. Neglectable transport and standby loss 5. Long term storage without loss 6. Safety – less flammable fluid
Disadvantages	1. Low volumetric energy density requiring many tours if transported with trucks/ships. 2. Cost intensive as high amount of steel is required due to the high pressure (thick tank walls)	1. Capital cost of installing refrigeration/cryogenic unit 2. High conversion loss 3. Normally high loss when transferring fluid from one vessel to another (all surfaces must be kept cold) 4. Boil off (or cooling or highly isolated) under transportation/standby	1. Capital cost of installing conversion unit 2. High conversion loss 3. Extra transport fuel as weight of carrier must be transported too (both forth and back)

Liquid fuels (LHC)

All fuels and LOHC that are liquids at P=1.025 bar and T=50°C will be treated as one group called liquid fuels (LHC). This group includes:

1. All hydrocarbons with carbon number (CNO) larger and equal to 5 (gasoline, diesel, HFO, MGO, Jet fuels, etc.)
2. All alcohols (Methanol, Ethanol, Propanol, etc.)
3. All liquid organic hydrogen carriers (LOHC)

All these fuels are stored and transported in the same manner as conventional liquid-hydrocarbons.

Liquid at ≥ 20 bar (L20) - NH_3, DME and LPG

This fuel group (L20) include fuels that are liquid at (P=20 bar, T=50°C) and vapor at (P=1.025 bar, T=50°C). All fuels within this group will all be transported and stored as liquids.

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[15] Might be a combination of cooling and pressurization

This group include NH_3, DME an LPG. Pure ethane is also part of this group but will require a little higher pressure to liquify than the others.

The liquefaction will always be via pressure when transported in pipeline while either pressurization, cooling or both can be applied when transported via truck, rail and ships.

Liquefied Natural Gas (LNG)

H_2 and NG

Fuels that are gaseous at 20 bar can either be transported as compressed gas (will always be the case for pipe-transport), cryogenic liquid or via a carrier (the latter is only for H_2). Hydrogen and natural gas require cryogenic cooling for liquefaction.

Pipe transport: As cooling is impractical, H_2 and NG will always be transferred as compressed gas in transmission pipes.

Mobile transport: NG will normally be transported as a liquid. Hydrogen is today mostly transported as compressed gas but liquid transportation exists too. As hydrogen requires extreme cooling, its optimal transportation (and storage) form is still under development. Figure below gives an overview of different ways that hydrogen can be transported/stored.

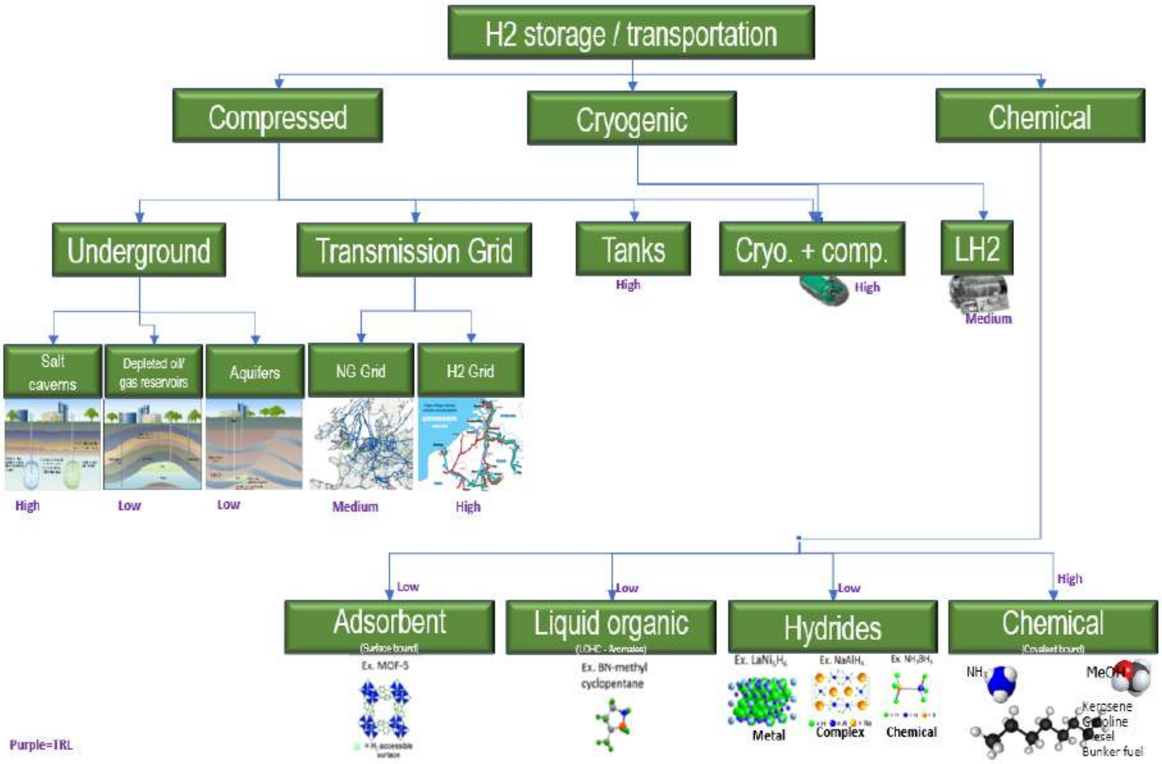

Figure 12: Different H_2 storage and transport technologies

LNG is liquefied natural gas for storage and transportation. At atmospheric pressure, LNG will have temperatures ranging from -161 degrees Celsius to -158 degrees Celsius.

The main component is methane (CH_4), and other components can be ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}) and nitrogen. Impurities may include CO_2, sulfur, COS, mercaptans, and mercury.

The boiling point is about -161.5^{o}C, and specific weights are in the range from 410 kg/m^3 to 500 kg/m^3 depending on temperature, pressure and composition.

Because it occupies only 1/600 of the volume of natural gas under standard conditions (15 degrees Celsius, 1 atm), LNG is a convenient form for storing and transporting natural gas from production sites to consumption markets around the world. The main means of transportation today are LNG ships with a load of 155,000 m^3 to 260,000 m^3, of which the most common load is from 155,000 m^3 to 170,000 m^3.

After being transported to the place of consumption, the LNG is transferred back to the gaseous state, as it passes through the regasification equipment, and then pumped into the transportation pipeline to the consumers. In remote areas, for households far from pipelines, coastal areas and offshore islands in LNG-importing countries, it can be transported by tankers, trains, and coastal ships with a load of 2,500-12,000 m^3 to the receiving port.

Figure 13: Transporting LNG by tank truck in Vietnam

In Vietnam, Liquefied Natural Gas (LNG) is mainly used as a fuel for gas power plants and industrial customers, helping to ensure national energy security and meet Vietnam's commitment to reducing emissions. In the section below, the main transportation plan from the warehouse to the gas power plant will be presented.

LNG supply: According to the national energy master plan towards 2050, in addition to LNG terminals dedicated to LNG power plants, Vietnam will develop LNG terminal projects to supply gas to consumers in the Northern/North Central, South Central, Southeast, and Southwest regions. Currently, Vietnam has the Thi Vai LNG Depot operating from 2024 with a capacity of 1 million tons/year and it is expanding to 3 million tons/year.

Figure 14: Thi Vai LNG Terminal

Road: LNG is transported by tanker trucks or specialized ISO containers (20 ft, 40 ft) along major road networks such as national and provincial highways. However, road transport of LNG requires a large number of vehicles, which may place pressure on the road traffic system and must comply with strict safety requirements. In addition, transportation costs by road are typically higher than by water. Therefore, inland waterway transport is generally the preferred option.

Figure 15: Transporting LNG by barge

Marine: LNG is transported by barges or vessels to the plant area or intermediate storage terminals via inland waterways of Class II or higher. This option leverages the river network, helping to reduce pressure on road traffic.

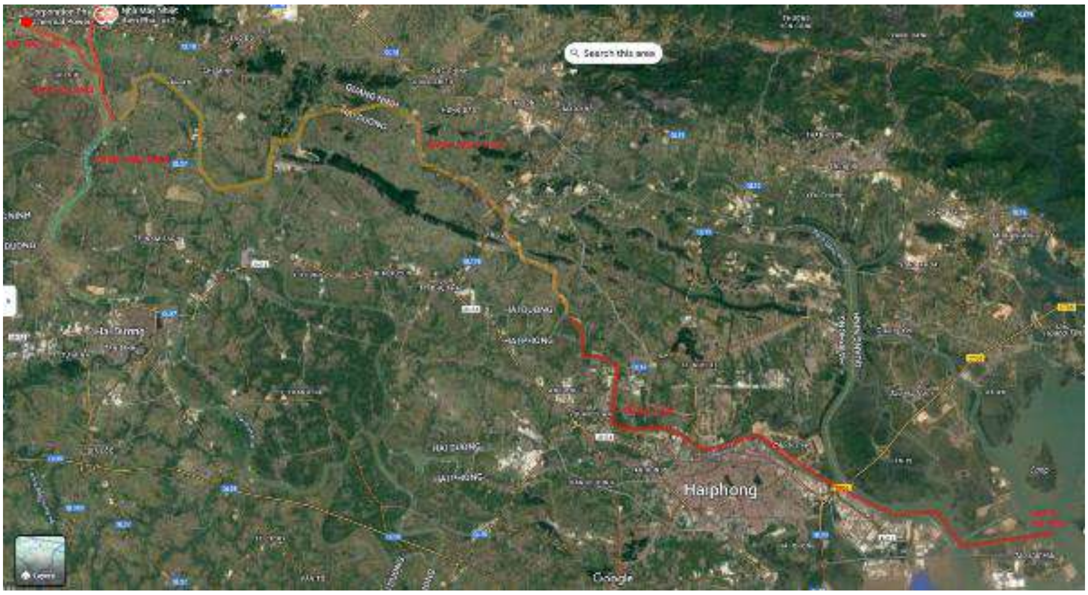

Figure 16: The channel route is expected to transport LNG from Hai Phong seaport to Pha Lai Thermal Power Plant

Hydrogen transport methods are determined according to the physical properties of hydrogen. To be transportable, hydrogen needs to be compressed to about 35 – 140 bar, liquefied, or incorporated into chemical conversions in other compounds.

In terms of transportation methods, hydrogen can be transported by:

- Roads and railways, in gas or liquid form, in special ships, pipes and containers;

- Sea transportation, mainly by specialized carriers;

- Pipeline, which can transport natural gas, hydrogen or blended products.

Transportation by Road and Rail

The common method of transporting hydrogen is in pressurized cylinders on trucks or ships, containers with a volume size of up to 150 liters.

Shipping by sea

The transport of hydrogen across the oceans has been studied primarily in the form of liquid hydrogen or as methylcyclohexane (C_7H_{14}). However, this technology is still in the research and development stage, and it is expected that this technology will be ready by 2040.

Pipeline Shipping

Blending a small proportion of hydrogen into natural gas allows the use of existing gas pipeline systems for transportation, thereby reducing costs, particularly in areas where infrastructure is already in place. In the long term, the refurbishment, upgrading, or replacement of existing natural gas pipelines can be carried out in parallel with the development of new, dedicated hydrogen infrastructure.

Table 17: Main hydrogen distribution methods [3]

Distribution form	**Pipe**	**By road**		**Transport of liquid hydrogen by road**	**Transport of liquid hydrogen by train**
		By dedicated storage tubes	**Transport of liquid hydrogen by road**		
Conformity	Transport of hydrogen (gaseous) in large volumes over long distances	Transport of hydrogen (gaseous) over short distances	Short and medium distances, transporting large volumes of hydrogen	Medium distances, transporting large volumes of hydrogen	High-volume, intercontinental hydrogen transportation
Investment Costs	$200,000 - $1,000,000 per kilometre depending on the terrain	About $300,000 per truck	$300,000 - $400,000 per truck	$2,000,000 - $4,000,000 per wagon	$465,000,000 - $620,000,000 per hydrogen carrier
Operating and maintenance costs	About $0.03/kg for pipeline compressors	Workers drive at about $18 per hour	Workers drive at about $18 per hour	Workers drive at about $18 per hour	
Effective	Above 99.2% for 100 km	94 % per 100 km	99 % per 100 km (liquefaction efficiency approx. 75 %)	99 % per 100 km (liquefaction efficiency approx. 75 %)	Evaporation rate 0.3 % per day
Energy Consumption	Up to 100 tonnes of hydrogen/hour (3.9 GW) of electricity required for pipeline compressors	Fuel consumption up to 400 kg per truck	Fuel and liquefied energy consumption up to 4000 kg per truck vehicle	Fuel and liquefied energy consumption up to 4000 kg per train vehicle	Up to 10,000 tons per trip
Advantage	Large quantities and lengths can be transported with high efficiency and low operating costs. This method will store large volumes of hydrogen	Suitable for small-scale consumers	Transport more than gaseous hydrogen transport	Transport more than gaseous hydrogen transport	Bulk international shipping over long distances
Disadvantage	The investment cost is relatively large, so this option is suitable for the distribution of large volumes of hydrogen	Small-scale delivery per vehicle, short-distance transportation	Large investment costs, poor transportation performance due to liquefaction and evaporation gas phenomenon	Rail transport of hydrogen requires suitable railway infrastructure and dedicated transfer terminals equipped with cryogenic storage tanks and loading/unloading systems. Therefore, additional investment in	Operating experience is still low. Suitable for large enough consuming households. Losses due to evaporated gases during transportation are still large

Distribution form	Pipe	By road		Transport of liquid hydrogen by road	Transport of liquid hydrogen by train
		By dedicated storage tubes	Transport of liquid hydrogen by road		
				infrastructure and specialized operational equipment is required.	
Total transportation cost for 100 km (USD/kg)	0.1 – 1.0	0.5 – 2.0	0.3 – 0.5	0.2 – 0.5	1.8 – 2.0

Vietnam does not have a gas pipeline system connected to consumers, but mainly uses pipelines to transport natural gas for nitrogen fertilizer plants, power plants, etc. In addition, mixing hydrogen into natural gas pipelines in Vietnam is not popular, so hydrogen transportation by road (compressed and liquefied) is prioritized for short- and medium-term use and supply of hydrogen from general warehouses to charging stations in the region. When Vietnam imports or collects large quantities of hydrogen from production facilities to domestic storage, the option of transporting liquid hydrogen by waterways and pipelines will be more efficient.

Liquid hydrogen require liquefaction. The energy loss under liquefication process is very high meaning that LH_2 only is optimal for very long-distance transport.

Hydrogen carriers are substances that are able to bind several hydrogen atoms. As hydrogen is more expensive to store/transport than other fuels, extensive research has lately been carried out to investigate whether hydrogen carriers are optimal for storage and transport of hydrogen.

Table 18: Different type of hydrogen carriers

	Description	Component (examples)	TRL	Advantages	Disadvantages
Adsorbent	Solid that adsorbs hydrogen on the surface or in the pores of complex materials via intermolecular forces.	Metal–organic frameworks (MOFs), graphene, carbon nanotubes	1	Materials can be reused many times. Stable materials.	Immature technology
Ion hydrides	Compounds consisting of hydride ions (H^+) and electropositive metals, typically an alkali or alkaline earth metal.	LiH, NaH, KH, MgH	2	Flexible source of hydrogen. Can be stored infinite under dry conditions.	Must not be exposed to any moist before the dehydration, pyrophoric Dehydrogenation is strongly exothermic => waste heat Highly alkaline waste after hydrogen release.
Covalent metal hydrides	The hydride is part of complex ions, where hydride is covalent bound to a metal atom.	LiBH4, NaBH4, LiAlH4, NH4BH4	2	More stable than ion hydrides	
Metallic hydrides	Hydride is nonstoichiometric bound/adsorbed/absorbed to precious metals and its alloys. Hydrogen is released by heating.	Precious metals (Pd, Pt)	2	Knowledge available from the Ni-Hydrogen battery technology.	High cost as currently made in small quantities and as require >95% purity.
Liquid Organic hydrocarbons (LOHC)	Liquid organic hydrogen carriers are organic chemical components that relatively easy can be hydrogenated/dehydrogenated.	See [13]	7	Transported and handled as liquid fuel are handled today.	Many different technologies for releasing hydrogen

	Description	Component (examples)	TRL	Advantages	Disadvantages
H_2 rich chemical	Non-carbon-based compounds that relatively easy can be hydrogenated/dehydrogenated.	NH_3, hydrazine	4-8	Except for the cracking into H_2, mature technology ready for large scale exploration.	Toxic. Untested as hydrogen supply. Very high cracking temperature required. NH_3 is poisonous to PEM fuel cell, i.e. no NH_3 traces after cracking

Liquid organic hydrocarbons (LOHC) and hydrogen rich chemicals are all transported as liquids (thus covered by LHC in this catalogue). Adsorbent, ion hydrides and covalent metal hydrides are solids and need special transportation which is not included in this catalogue.

Transport unit – pipeline, truck, train or ship

Ways to transport fluid are listed in Table 16 together with key advantages/disadvantages.

Table 19: Ways to transport major amount of fluids and associated advantages/disadvantages

	Advantages	Disadvantages
Pipeline	- Limit number of intermediate storage/compression stages. - Combine transport and storage - Very low OPEX - Very low risk - Can transport large amount of energy much cheaper than electric cables	- High CAPEX - Less flexible than mobile transportation
Trucks	- Provide point to point solutions, i.e. limit number of intermediate storage/compression stages	- Risk is higher than pipeline, train and ships - Size limited to max weight, width and length of a truck
Trains	- Risk are lower than trucks but higher than pipelines	- No point-to-point solution – needs other transportation form in both ends - Size limited to max weight, with and length of train carriage
Ships	- Less fuel consumption per distance: ship ~0,3 MJ/ton/km, train ~0,6 MJ/ton/km, road ~1.2 MJ/ton/km. Reason is less friction loss due to buoyancy forces. [4] - Size limitation: much larger amount can be transported per trip than on trucks and trains - Social risk (the amount of people that can die if an accident occurs) is much less offshore than onshore (see ***Safety***) - Cheapest option for very long distances	- No point-to-point solution – needs other transportation form in both ends

Overall:

1. Truck: optimal for low capacity, short distance, onshore transport
2. Train: A common method of transporting hydrogen is in pressurized tanks on trucks or ships. These containers can be of industry standard size (volume up to 150 liters) or larger tubes.
3. Ship: optimal for long distance where a valid offshore route exists
4. Pipeline: optimal for larger quantities and/or many consumers

Figure 17: Train transporting NH3 from Russia to Europe

In Vietnam, in September 2024, the first shipment of liquefied natural gas (LNG) was transported from the South to the North by train. The train carrying 16 ISO tanks containing LNG has completed a journey of 1,700km on the railway from the South to the North. This is a breakthrough business plan, solving the problem of energy supply for the Northern market. Transporting fuel by railway in Vietnam is an effective and cost-effective method, especially suitable for transportation of large volumes and long distances, helping to reduce the load on the road and contributing to environmental protection.

Figure 18: Ship transporting LNG from South to North

Material of construction

Hydrogen (H_2)

Hydrogen embrittlement is cracking associated with hydrogen penetration into the metal grid. At low pressure (<150 bar), hydrogen is only able to enter materials in the form of atoms or hydrogen ions. Thus, pure gaseous hydrogen is not absorbed by materials at ambient temperatures, as it is in molecular form. However, dissociation of hydrogen into H-atoms can occur due to (point 2-4 can occur at temperature below 150°C):

1. High temperature[16] (>150°C, very little <200°C) [5]
2. Surface irregularities (impurities in the hydrogen and at the surface)
3. Corrosion
4. Electrochemical or chemical surface treatment
5. Cathodic protection

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[16] Material is normally exposed to hydrogen at high temperature under manufactures (casting, carbonization, coating, plating, cleaning, pickling, electroplating, electrochemical machining, welding, roll forming and heat treatment).

Any penetration of H-atoms into the metal grid may lead to hydrogen embrittlement when temperature is below ~150°C.

Hydrogen embrittlement can only occur in combination of the following three factors:

1. A susceptible material
2. Hydrogen environment (H^+-ion formation – see points above)
3. High tensile stresses

Thus, if stresses are sufficiently low, the environment not sufficiently aggressive, or the material not susceptible, the hydrogen will diffuse through the material without causing damage.

Susceptible material: ASME B31.12 specify material requirements to hydrogen pipes[17] and material grades that are approved for hydrogen pipes. For design pressures (Pd) <200 barg and design temperatures (Td) <175°C Carbon steel (A 105/A 106) and Micro alloy steel (X42 and X52) is applicable. For Pd>200, high alloy steel (SS-316L) should be used [6]. X70 may be used subject to evaluation of the hardenability in weld heat affected zones. Within this catalogue, X52 have been used.

High tensile stresses: The stress levels can be lowered by:

1. Closer pipe support
2. Thicker pipe walls
3. Thermal relieving residual welding stresses
4. Hydrotesting (autofrettage)

Ammonia (NH_3)

Ammonia is corrosive to:

1. Copper
2. Copper alloys
3. Zinc
4. Nickel (must be kept below 5 wt%)
5. Most plastic

Oxygen levels of more than a few ppm in liquid ammonia can promote stress corrosion cracking especially at high temperatures. Ammonia and oxygen induced SCC are not expected at ambient temperatures, but stresses caused by welding can initiate SCC if oxygen is present. Ammonia as produced contains no oxygen. However, when filled into a tank, it must be ensured that the tank is purged until <0.5% oxygen before NH_3 is admitted.

Figure 19: Transporting ammonia by tank truck in Vietnam

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[17] The key material requirements are also listed in [6] and [15].

Water content in ammonia should be > 0.1 wt %. Research has shown [7] that presence of water inhibit the formation and growth of SCC (see grade specification under *Ammonia (NH_3)*).

Steel piping is suitable for ammonia gas and liquid. Within this catalogue X52 have been applied.

Currently, in Vietnam, ammonia (NH_3) is mainly used as an input material for nitrogen fertilizer production industrial plants, in addition, in thermal power plants, ammonia is used as a reducing agent to convert harmful nitrogen oxide (NO_x) emissions into harmless nitrogen gas (N_2) and steam (H_2O). helping to clean exhaust gases and protect the environment. Ammonia can be supplied as anhydrous ammonia and aqueous ammonia (ammonium hydroxide solution).

Safety

Key safety parameters are listed in Table below. All fuels are flammable with H_2 being the most flammable/explosive. NH_3 does also have toxicity impact (see section *Ammonia (NH_3)*).

Table 20: Key safety parameters

		H_2	**NH_3**	**DME**	**LHC/Toluene**
Toxicity		None	See ***Ammonia (NH_3)***	None	Depend on chemical. Liquid, i.e. leakage do not lead to inhalation.
Flammability/ Explosion limit[18], %	Lower (LFL/LEL),	4	15	3.4	1.1
	Upper (UFL/UEL)	75	28	27	7.1
Flame		Very difficult to see	Yellow	Blue	Most white + yellow
Flash point, C		NA	11	-24	≥6
Auto ignition point, C		560	651	235	200-500
Ignition energy, mJ		0.017	680	0.29	>0.2, most ~0.25
Detection limit air		25 ppm	5-50 ppm (smell), ~1 ppm	-	-

For every system the risk (= probability × severity of consequence) must be quantified. If risk violates acceptance criteria, measures to eliminate, reduce the probability and/or consequence must be taken.

Collision

The probability for collision between mobile transport depend strongly on where the transport is carried out. Generally, the likelihood for collision is much higher in populated areas, i.e. in cities, on train stations or in harbours. Additionally, the likelihood for collision on road is much more likely than collision with train or ships. Contradictory, if a collision occurs, then probability of tank rupture, and leak of large amount, is much higher from thin-walled tanks that carry cooled liquid (which is the most common liquefaction method on ships) than for thick-walled tanks that carry pressurized liquid [8].

Loading/unloading

Due to the nature of fuels, loading (and unloading) is a very critical process that must be executed with utmost safety precautions. Any leakage is critical.

It must be ensured that all loading systems/tanks are emptied for oxygen before exposed to fuels. Any purge with inert gas to remove oxygen must subsequently be vented to prevent contamination of fuel with inert gas. Tank-purge can be avoided if the tank is only used for one fluid type and the tank is kept at slightly overpressure to prevent ingress of air. This is common for CH_2 tube trailer tanks.

If loaded with refrigerated/cryogenic liquid, the loading system/tanks must either be pre-cooled or loading must be slow to prevent uncontrolled pressure rises and unsafe temperature gradients. Due to the sub-zero boiling points at atmospheric pressure of LPG, NH_3, DME and H_2, the refrigerated liquids that are entering

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[18] Gas to air ratio

tanks and piping which are at ambient temperature and pressure immediately begin to boil. Boiling and evaporation will continue until the materials reach the liquid temperature. This initial boiling will cause a rapid pressure increase in the loading system. The pressure attained will depend on the quantity of liquid and the heat available for evaporation. Care should therefore be taken to introduce liquids into non-cooled tanks sufficiently slowly to avoid an uncontrolled pressure rise. The initial boiling will also cause local cooling of the tank structure, with the risk of thermal stresses of the materials. Spray cooling[19] is essential for very cold cargoes.

Leakage

Pipeline is the safest mode of transporting fluid fuels. Long-distance pipelines must fulfill high demands of safety, reliability and efficiency. If properly maintained, pipelines can last indefinitely without leaks. Significant leaks that occur are normally caused by damage from nearby excavation or by corrosion caused by incorrect operation.

Pipeline is normally equipped with some leakage detection system. Leakage detection systems can include:

1. Internal leakage detection systems:
    a. Sensors and computer system that via a series of pressure and flow rate sensors and mathematical models estimate whether leakage occur.
    b. Acoustic pressure waves measures.
2. External leakage detection systems: Infrared radiometers, thermal cameras (above ground only), gas detectors, acoustic sensors, and digital oil leak detection cable.
3. Odor addition: see section *Odorization.*

In case a leakage is detected, insulation valves and associated vents are installed frequently (for every 10-20 km) so the leakage can be isolated, vented and repaired without having to empty the entire pipeline.

Sectionalization

Pipelines and larger transportation tanks are sectionalized (pipes with ESD valves that are closed in case of an emergency) to mitigate the risk of very large leakages, fires and explosion.

Hydrogen (H_2)

Due to the low flash point, low ignition energy and wide flammability range, the probability that hydrogen ignites immediately is very high. For cryogenic liquefied H_2, burning is also a risk.

Monday June 10, 2019, a hydrogen gas filling station at Kjørbo (near Oslo) in Norway caught fire and exploded. Three people were treated for minor injuries due to airbags deploying in their car nearby. The fire caused severe damage on the filling station. A root cause analysis by the authorities, Nel and Gexcon has identified the cause to be an assembly error of a specific plug in a hydrogen tank in the high-pressure storage unit. Due to human error, the inner bolts of the plug had not been adequately torqued. This led to a hydrogen leak, which created a mixture of hydrogen and air that self-ignited, which created an explosion (pressure wave) and fire.

Ammonia (NH_3)

The major safety concern related to ammonia is its toxicity issues:

Table 21: Ammonia toxicity exposure levels [2][7][9]

Conc. ppm	**Exposure period**	**General effect**
5-50	Max 8 h	Odor, detectable by most persons, Mild discomfort
50-80	2 hours Exposure for longer periods not permitted	Perceptible eye and throat,
100		Nuisance eye and throat irritation
140	2 hours	Serve irritation, need to leave exposure area

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[19] Cargo tanks are cooled down by spraying the initial loaded fuel (LNG) through spray nozzles

Conc. ppm	Exposure period	General effect
134	5 min	Tearing of eyes, eye-, nasal-, throat- and chest irritation
500	30 min	Upper respiratory tract irritation
700	<1 h	No serious injuries and repeated exposure produce no chronic effect
700-1700	Can be fatal after 30 min	Convulsive coughing, Severe eye, nose and throat irritation, Incapacitation from tearing of eyes
5000-2000	Can be fatal after 15 min	
5000-10000	Rapidly fatal (within min)	Respiratory spasm, Rapid asphyxia
>10000	Promptly lethal	

As ammonia is a toxic gas, it must be transported according to local legislation which normally means requirements to general safety procedures concerning:

1. Leakages
2. Minimum allowable cargo tank steel temperature
3. Firefighting and emergency procedures
4. Training of personal - driver/crew must complete specific training

Safety measures for handling ammonia include:

1. Protective full body chemical protective clothes, googles/face shield, gloves and safety footwear
2. 5 gallons of water (first aid if skin or eyes are exposed) and breathing apparatus

Figure 20: NH3 leakage - Panaji

Ammonia poses some challenges to ensure safety of the crew on ships as personnel cannot escape. Thus, any leakage can be fatal why piping and vessels normally are double walled with leakage detectors between the double wall.

Odorization

Odorant (normally tetrahydrothiophene (THT) or mercaptan) is added to the NG distribution net and partly to the NG transmission net, allowing leaking gases to be detected before it reaches combustible levels. The disadvantages with odorants are:

1. Humans must be present in the vicinity of the leak and not all are able to detect the odours at the mandatory level.
2. Commercial odorants are poisons for catalyst used in most synthesis and in hydrogen-based fuel cells. Thus, cost of removing odours will be high.

Due to these disadvantages and as it is assumed that the hydrogen net mainly will be a transmission net (and not a distribution net in densely populated areas), odorization is not recommended as a safety solution and will not be included in the performance and cost evaluation of hydrogen transmission piping.

Transport chain - logistic and infrastructure

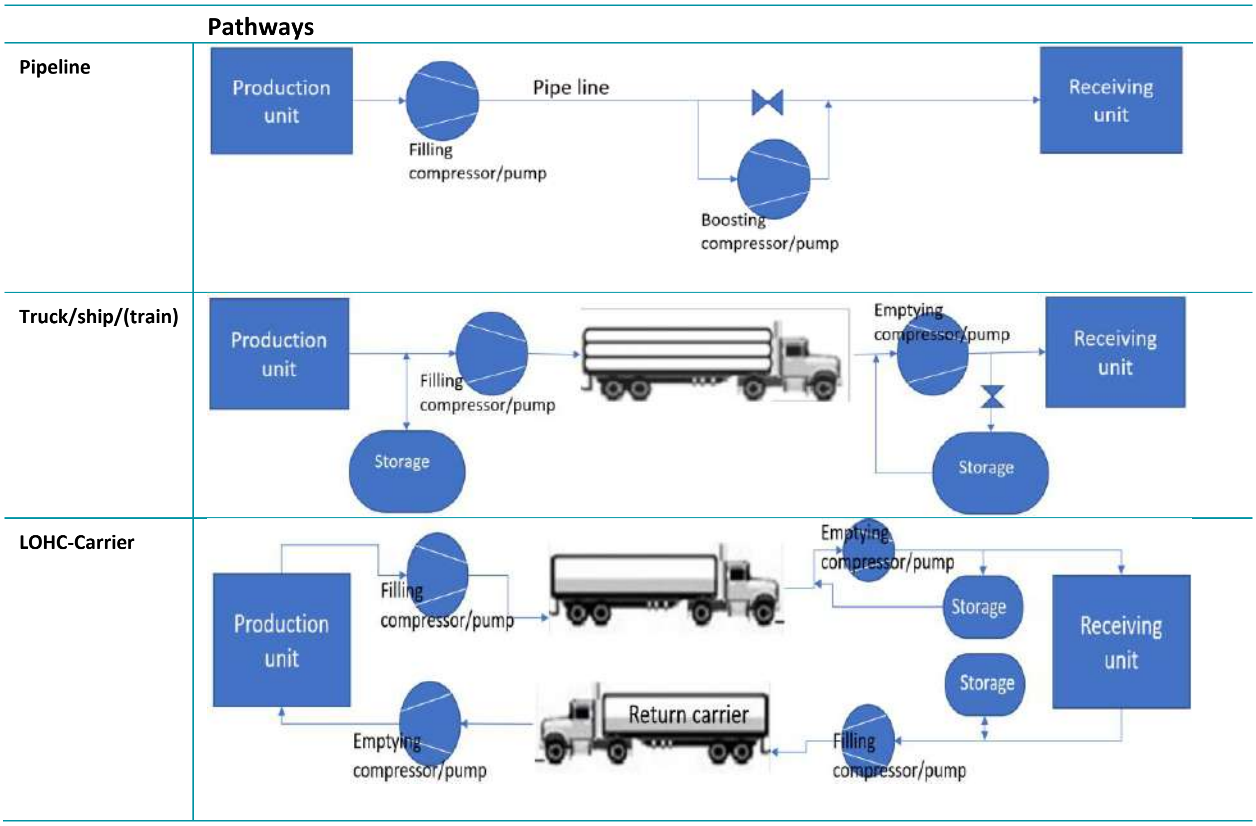


Figure 21: Infrastructure for the different transportation solutions

While filling compressor/pumps are used to transfer the fuel from the production unit to the transportation unit, emptying compressor/pump is used to transfer the fuel from the transport unit to the receiving unit. Emptying compressors/pumps may for liquid fuels be replaced with gravity.

Pipeline: Key elements are the pipeline, filling and boosting pressurization units. Boosting compressor is compressor/pump substations along the pipeline that boost the pressure to compensate for pressure drop along the pipeline.

Truck, ship, train: Key elements are the transportation unit (truck, train or ship), filling and emptying compressor/pump and storage tank in each end.

LOCH-carrier: Same key elements as above except that the carrier must be transported back again if not used at the receiving unit. The production unit includes the conversion to carrier and liquefaction by cooling.

Whether additional storage and compression/pumping facilities are needed will depend on the actual design. However, when designing infrastructure, it is important to notify that transfer of gas or liquefied fuel from one vessel to another inherit the following losses:

1. **Compression/pumping losses:** Especially compression is complex and can inherit larger losses as the pressure drops on the suction side, and increase on the discharge side, while emptying and filling the vessels.
2. **Cooling losses:** need to cool down the material of the new storage vessel

To limit these losses, it is optimal to limit the number of vessels in the infrastructure. Thus, it should be considered whether the storage and transportation tank could be the same vessel.

Hydrogen battery

Figure 22: Hydrogen storage, transportation and fuel tank.

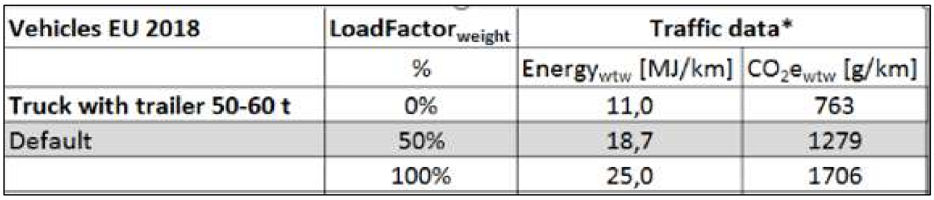
The section *Energy losses* gives and overview of the various sources of energy losses. The sections *Conversion to/from carrier (LOHC)* to *Storage tanks* describe the units within the transport chain and section *Examples - full transportation chain* gives some overall loss and cost calculation examples.

Energy losses

Depending on transport phase (gas or liquid) and transport unit (pipeline, truck, train or ships), the energy losses may include:

1. **Conversion to/from a carrier** (only for hydrogen) (see *Conversion to/from carrier (LOHC)*)
2. **Cooling losses** – losses in conversion to liquid phase via cooling.
    - Refrigeration of NH_3, LPG and DME (see
    - *Refrigeration of NH_3, LPG and* DME)
    - Cryogenic liquefaction of NG and H_2 (see *Cryogenic Liquefaction of NG* and *Cryogenic Liquefaction of H2*)
3. **Pressurization losses** – shaft power and interstage cooling losses within filling, boosting and emptying compressors/pumps.
    - Compression losses (for CNG and CH2) (see *Energy loss – reciprocating H2 compressor*)
    - Pumping losses (for LH_3, LPG, LDME, LNG, LH_2) (see *Pumps*)
4. **Fuel for propulsion (for truck, train and ships)**: Fuel consumption depends on weight due to increased resistance and increased force needed when accelerating.

Table 22: Fuel consumption [10]



Vehicles EU 2018	LoadFactor$_{weight}$	Traffic data*	
	%	Energy$_{wtw}$ [MJ/km]	CO_2e_{wtw} [g/km]
Truck with trailer 50-60 t	0%	11,0	763
Default	50%	18,7	1279
	100%	25,0	1706

As a truck is full one way and empty the other way, 19 MJ/km is used as average (19 MJ/km is ~50% load). For CH_2, the fuel is carried in thick-walled tubes, and for LH_2, the fuel is carried in a double walled tank. Thus, for CH_2 and LH_2, 24 MJ/km have been used as an average as the fuel-tanks have a higher weight and the transported fuel per truck is lower.

Ships: The fuel consumption per day of a ship can be described by the Barras formula [11]:

$$\text{Fuel consumption/day} = \frac{W^{2/3} \times v^{3}}{Fc}$$

Where

W=ship´s displacement (total weight) in tons

v= ship´s speed in knots (typically between 12-14 knots)

Fc= Fuel coefficient (Fc=120.000 for diesel engine)

As ships displacement is not always given, the following approximation has been made based on average from various sources (valid if velocity ~13 knots):

$$\text{Fuel [MJ/km]} = 0.023 \times M_{cargo} + 1400$$

Where M_{cargo} is the weight of the transported fuel in tons. Normally a tanker is empty on the return route, meaning that the fuel consumption for propulsion is approximately half of the delivery trip.

5. **<u>Heat interaction with the surroundings - Boil-off (for cooled liquids)</u>**

   If the temperature of the transported fuel is different from ambient, there will be some minor loses due to heat-interaction with the surrounding. Thus, if the fuel transported is colder than ambient, energy needs to be added to keep it cold. If not, some vaporization/boil-off will occur. Typically, boil-off rate (BOR) from double walled vessels with vacuum between are:

   - LH_2: 2-3 %/day for small portable H_2 containers and down to 0.06%/day for large. Typical boil-off is ~0.1/day [12]
   - LNG: Typical 0.15-0.6 %/day on ships

   This boil-off loss can be minimized if the mobile unit is using the boil-off for fuel. Thus, under the transportation the boil-off can be eliminated but not when the transportation stops.

6. **<u>Leakage:</u>** Leakage is assumed negligible.
7. **<u>Heating before depressurization</u>** (only for CNG): On NG transmission pipes, there are additional losses associated with depressurization as NG must be heated before depressurized. For hydrogen, heating before depressurization is not needed as hydrogen do not cool upon depressurization when >-150 °C.
8. **<u>Odor removal</u>** (only for CNG): Odor is often added to NG net. Thus, losses are associated with removing the odor. As per discussion in section *Odorization*, odor is not considered for hydrogen transmission pipes.

Conversion to/from carrier (LOHC)

LOHC (liquid organic hydrogen carrier) are organic hydrocarbon liquids with hydrogen "adsorbing" capabilities.

Conversion and reconversion losses today are 30-40 %. Theoretical possible is 18% and potential obtainable minimum loss is 25% [13].

Convert to liquid phase by cooling

Figure 23 gives an illustration of the steps and losses involved in conversion and transportation as liquefied fuel. The losses in liquefaction can in principle be recovered. However, as the liquefaction and regasification will be at two different locations, the calories extracted from the liquefaction will normally be lost.

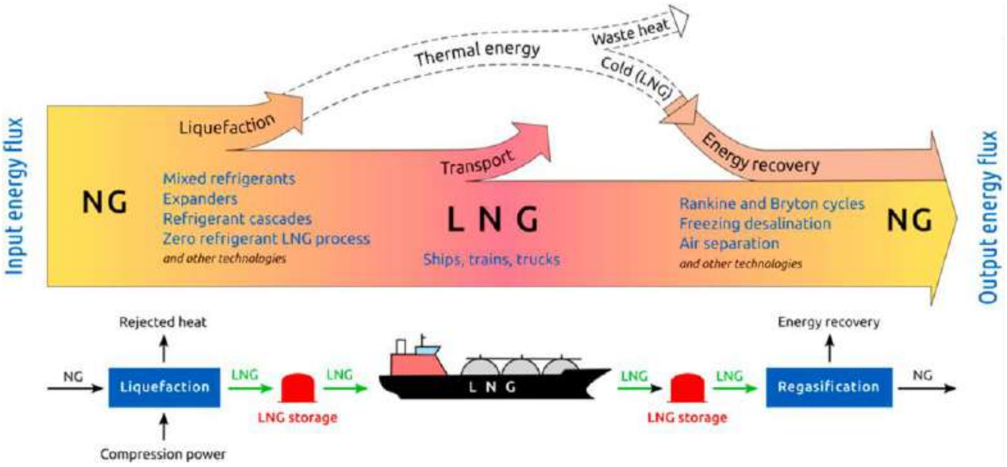


Figure 23: Illustration of steps and losses in transport of LNG. The other liquefied fuels include the same steps [14]

Refrigeration of NH_3, LPG and DME

The energy removed by the liquefaction is the energy required to cool to boiling point plus the energy required for condensation. For NH_3, LPG and DME, the energy removed by the condensation is the dominating term. or ammonia it is ~7.4 **%** of the LHV, while for LPG it is ~0.9% and for DME is ~0.47 % of the LHV.

NH_3 and DME are normally produced as cooled liquids so this step is not needed.

Cryogenic Liquefaction of NG

According to [12], the energy loss associated with liquefaction of NG is between 4-7%.

Cryogenic Liquefaction of H_2

The loss in the liquefaction process is between 25-45%, strongly depend on the capacity of the plant. The theoretical possible minimum loss is 18% [15].

Hydrogen exists in two forms. At very low temperature it is para- H_2 while at ambient ~75% is ortho- H_2. The transition from ortho to para is very slow and releases significant amount of heat (527 kJ/kg) [12]. Thus, liquefaction of hydrogen, i.e. transferring H_2 (mainly ortho- H_2) to LH_2 (para- H_2) must be done over a catalyst ensuring all is para- H_2 before transportation/storage of LH_2. If not, 30% of the hydrogen will boil off within two days if stored in full cryogenic tank.

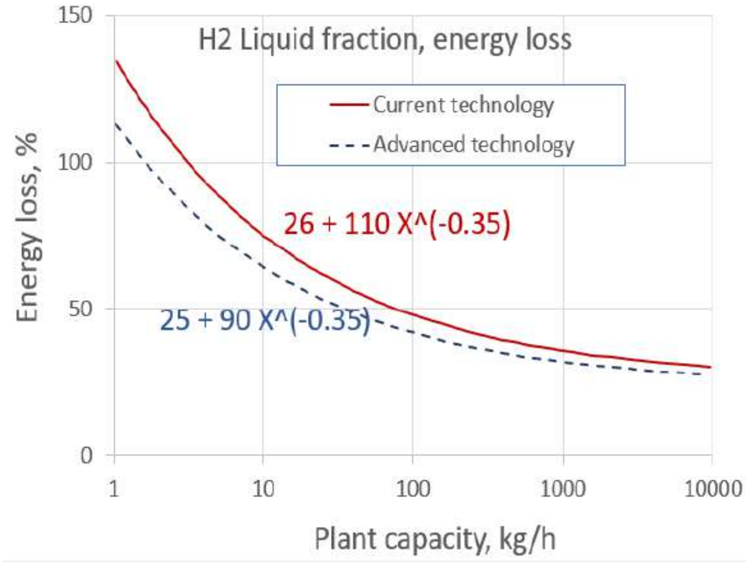


Figure 24: Energy loss associated with liquefaction of H_2 [15]

Compressor

Only H_2 compressors are covered within this catalogue.

Types - hydrogen compressors

High grade hydrogen is normally a requirement. Thus, non-lubricated compressor is required to avoid oil contamination in the hydrogen.

Reciprocating/piston compressors are optimal when requiring high compression ratio (and/or having low flow and large flow variations). Thus, reciprocation compressor is optimal in most hydrogen services and will therefore be the only one considered in the performance and cost estimate.

Of reciprocating compressors, the following types exist:

- Metal piston (free or crankshaft piston)
- Diaphragm piston

- Ionic liquid piston (do not require lubrication)

Future alternatives to reciprocating compressors may be the ones listed in Table below.

Table 23: Hydrogen compressors under development

Compressor type	**Description**
Hydride Compressor	Compressors where H_2 is adsorbed by a hydride at ambient conditions. The absorbent is then blocked in and heated whereby the pressure will increase. Compression ratio >20 and final pressure > 1000 bar is possible. However, the product will be a hydrogen flow at high temperature which is impropriate for transportation. It has a low TRL but may be optimal in the following cases: (i) H_2 need to be extracted from an impure H_2 rich stream (ii) H_2 is needed at high temperature
Electrochemical hydrogen Compressor (EHC)	EHC is a compressor where the hydrogen is supplied at low pressure at the anode and via electricity is forced through a proton exchange membrane (PEM) to the high-pressure cathode side. EHC are noiseless, scalable and with energy efficiency of >80%. TRL=3-5.

Energy loss – reciprocating H_2 compressor

Energy loss associated with compression include shaft power and power used to operate the cooling system of the interstage coolers.

Shaft power required for compression are given in Figure 25:

1. Adiabatic compression (blue curve): Have no interstage cooling – represent maximum losses
2. Isothermal compression (green curve[20]): Have infinity number of interstage cooling – represent minimum losses, i.e. the ideal compressor

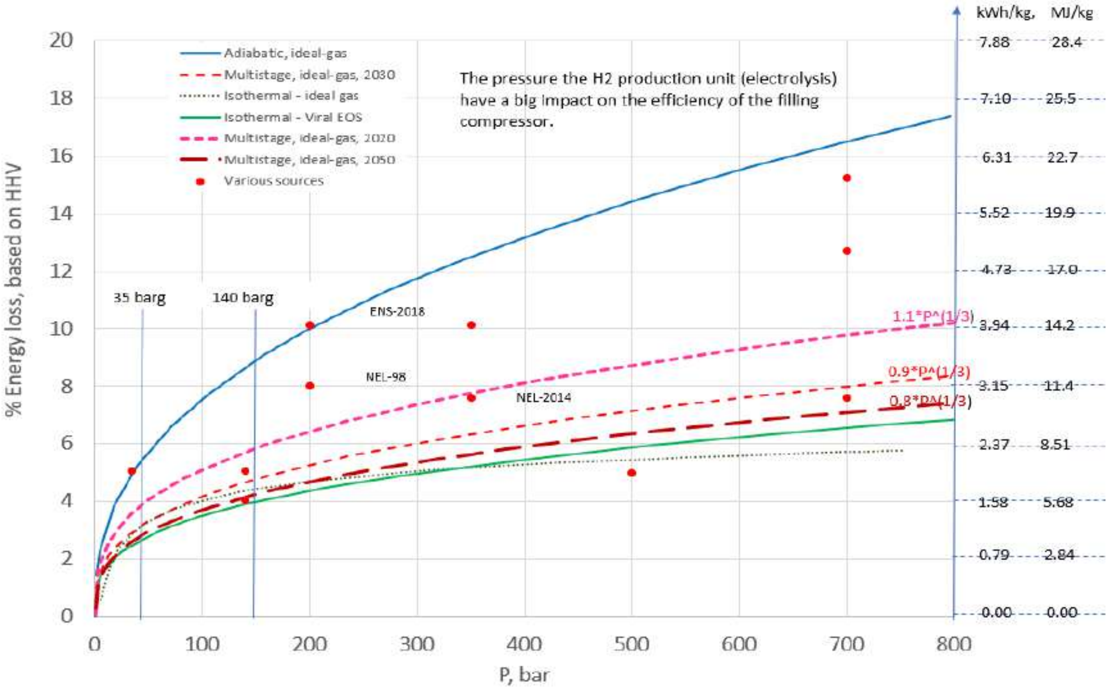

The pressure the H2 production unit (electrolysis) have a big impact on the efficiency of the filling compressor.

Figure 25: Energy loss for adiabatic, multistage with interstage cooling and isothermal compression (reciprocating H_2 compressors). Points from various sources have been added. Numbers along the secondary y-axis are absolute loss.

Most hydrogen compressors are multistage compressors with interstage cooling. Thus, the red curves are used in the performance calculation within this catalogue (the pink is assumed today status, the red is 2030 and the dark red is 2050).

---

[20] The two green curves calculate the same but with different thermodynamic models (ideal gas law and Viral equation of state) where the stipulate is more accurate

In addition to the shaft power, power used to operate the cooling system must be added too. This usually includes pump loss which is very minor compared with the shaft power.

The following formula is used in this catalogue to calculate compression power loss (Pin=suction pressure [bar], Pout=discharge pressure [bar], A=1.1 in 2020, 0.9 in 2030 and 0.8 in 2050 as per Figure 25):

$$\text{Loss (\%)}=A\times\left(\text{Pout}^{\frac{1}{3}}-\text{Pin}^{\frac{1}{3}}\right),\quad \text{see figure above for value of A}$$

$$\text{Loss (kWh/kgH2)}=\frac{\text{Loss (\%)}}{100}\times 39.42\frac{\text{kWh}}{\text{kgH2}}$$

Table 24: Calculate compression loss compressing H_2 gas from 35 bar to 140 bar

Calculation example		
Pin, bar	35	
Pout, bar	140	
A factor	1.1	A=1.1 (2020), 0.9 (2030), 0.8 (2050)
Loss (%)	2.1	= A*($Pout^{1/3}$-$Pin^{1/3}$)
Loss (kWh/kg)	0.8	= Loss (%)/100%*39.42 kWh/kgH_2
Loss (MJ/kg)	3.0	= Loss (kWh/kg)*3.6

The compressor operation cost can be lowered substantially by:

1. **Increasing the suction pressure:** Increasing the pressure in the H_2 production unit (electrolysis) will have a huge impact on lowering the operation cost of the compressor as the first steep part of the curve will be cut off.
2. **Increasing the number of stages:** Increasing the number of compression stages, and thereby approach the isothermal operation (green line in in Figure 25) will increase the compressor-efficiency. Additionally, multistage pressure level will also enable optimization with respect to the discharge pressure such that gas is only compressed to the current discharge pressure (the discharge pressure will be increasing when filling a tank on a truck/ship and will vary if using pipe-net as buffer/storage)

Pumps

Internal tool has been used for cost and efficiency estimation of pumps.

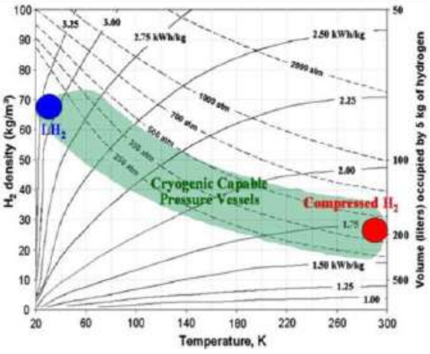
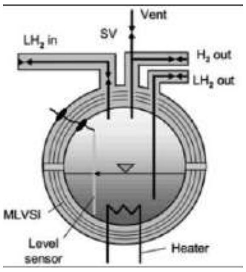
Fiscal metering stations

For transmission piping, normally two fiscal metering stations (one redundant ensuring correct measure) with associating lab/sample station will be installed at all filling stations. The cost of fiscal metering station and associated lab depends strongly on how the fluid is produced, i.e. which impurities should be detected, and has been judged outside the scope of this catalog.

Storage tanks

Storage will be in steel or fiberglass (later for hydrogen) tanks. Optimally the shape is spherical (gives largest wall strength per thickness and less heat exchange with surrounding per volume stored). However, as spherical shape takes up more space, cylinder shape is often applied, especially for hydrogen storage.

In Figure 26, a typical storage form is given for H_2, NH_3, DME and LPG. CAPEX for storage pressurized (up to 20 bar) and refrigerated tanks (down to -33 °C) is given too.

	Pressurized storage	Pressurized and cooled storage	Cooled storage
H_2	P=165–550 bar, T=Amb. Thick walled metallic (Type I) or composite reinforced tank (Type II, II, IV)  See cost and further description in [13]	 Red is CH_2, Blue is LH_2 and green is a combination of the two.	T=-253°C, P≤3.5 bar 
NH_3, DME, LPG	<100 ton, T=Amb., P≥20 bar 	100-1000 ton, T=0°C, few bars 	>10000 ton, up to 40000 t T=-33 °C, P=atm. 

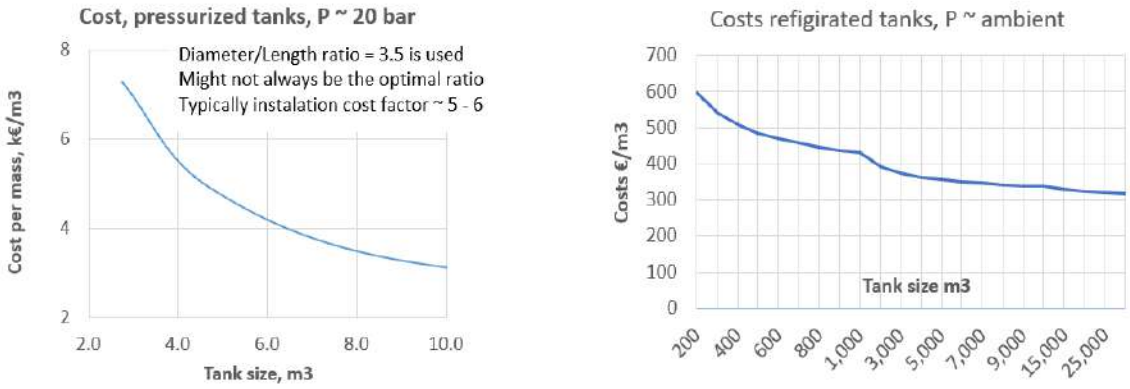


Figure 26: Typical storage form vs fuel and transport phase

Examples - full transportation chain

This chapter provides examples where the transport loss and the cost are calculated.

Colour codes for all the calculation examples are:

1. blue=input
2. red=numbers obtained from this document either from datasheet or given formulas
3. green= numbers obtained from internal cost estimation program
4. black = calculated values

Pipeline – CH_2 calculation example – small pipe

This example shows the cost and losses associated with a small 100 km pipeline for transporting 100 MW H_2 (could be a branch off pipe to a fueling station). Input assumption include:

- Operation and maintenance costs are assumed to be 4% of CAPEX.

- WACC is assumed to be 5%.

- Lifetime: 20 years for compressors and metering systems, and 50 years for pipelines.

- Transport velocity: 7 m/s

The example is comparable with the example in section *Truck – CH2 calculation example,* where truck transport of the same capacity is calculated.

The loss and investment costs are as follows::

1. Filling compression loss =2.1% of MW H_2.
2. Booster compressor loss =7.5 % of MW H_2, CAPEX for filling compressor =48 k€/MW, CAPEX of metering and scraper trap =5.2 M€ and CAPEX for pipeline =2559 €/(km*MW).
3. Total cost: 3,288,000 €/year.

The transport chain does not incorporate any storage. Optimally, storage can be avoided but, in most cases, it might be added. In such case, the capacity will depend on the various demands so it is omitted.

Pipeline – CH_2 calculation example – big pipe

This calculation example is similar to the previous one, but applies to a higher capacity and a longer transport distance. It illustrates the costs and losses associated with a small pipeline of 500 km used to transport 4,000 MW of hydrogen.

The assumed losses and capital investment costs are as follows:

1. Filling compression losses: 2.1% of hydrogen capacity (MW).
2. Booster compressor losses: 2.5% of hydrogen capacity (MW). The CAPEX for feeding gas into the compressor is 8,800 €/MW, the CAPEX for the metering system is 5.2 million €, and the CAPEX for the pipeline is 351 €/(km·MW).
3. Total cost: 107,229,000 €/year.

Truck – CH_2 calculation example

This example calculated the cost associated with truck transport of CH_2. It is calculated with the same transported capacity as pipeline in the section *Pipeline – CH2 calculation example*. Input assumption include:

- O&M costs are assumed to be 5% of CAPEX.

- WACC is assumed to be 5%.

- Transport distance: 100 km.

- Truck capacity: 1.5 t per truck.

- Density: 33 kg/m^3.

- Transport speed: 60 km/h.

The assumed losses and capital investment costs are as follows:

1. Filling compression losses: 4.2% of hydrogen capacity (MW).
2. CAPEX for feeding gas into the compressor: 50,000 €/MW.
3. Total cost: 9,759,000 €/year.

The red OPEX parameters for the loading/unloading and driving are found in the datasheet for the truck.

Storage has not been included; If filling compressors do not fill directly into truck-trailer tubes, storage and additional filling compressors are needed. Alternatively, if produced hydrogen is filling directly into the trailer tubes, additional trailers are required.

A loading arm is also missing, but this is assumed to be neglectable compared with the other costs.

It can be observed that transporting the same amount of gas by truck is more expensive than transporting it via pipeline.

Ship – LNH_3

This example gives an overview of the cost associated with LNH_3. LNH_3 is produced as a liquid so liquefaction of NH_3 is not included.

For ships, storage tanks in both departure and destination harbour are required as well as filling/emptying pumps and loading/unloading pipes.

The cost of transporting NH_3 by ship includes:

1. Fuel consumption: 2,435 MJ/km.
2. Ship CAPEX: €1,750 per ton.
3. Port costs: €1.7 per ton.
4. Total cost: €10,223,000 per year.

The above examples represent illustrative reference costs based on the Danish Energy Transport Catalogue. Hydrogen (H_2) and ammonia (NH_3) fuels are not yet widely used in Viet Nam; therefore, specific local cost data are currently unavailable.

2.1. Transportation of gas and liquid fuel by pipeline

Brief technology description

The fundamental principle of transporting gaseous and liquid fuels via pipelines is that the gas is compressed to high pressure and conveyed continuously through a closed pipeline system by maintaining a pressure differential between the inlet and outlet. Pressure is sustained and regulated through compressor stations installed along the pipeline route to compensate for pressure losses caused by friction and terrain. The transportation process is continuous, stable, and largely independent of weather conditions.

Currently, Viet Nam does not have a gas pipeline system directly connected to end-users. Pipelines are mainly used to transport natural gas to fertilizer plants, power plants, etc. In addition, hydrogen blending into the existing natural gas pipeline system is not yet common. Therefore, road transport of hydrogen (in compressed and liquefied forms) will be prioritized in the short and medium term to supply hydrogen from central storage facilities to regional refueling stations. When Viet Nam imports or collects hydrogen in large volumes from production facilities for delivery to domestic storage terminals, transportation options such as liquid hydrogen shipping and pipelines will offer higher efficiency.

Liquefied natural gas (LNG) is natural gas that has been liquefied for storage and transportation purposes. At atmospheric pressure, LNG has a temperature ranging from approximately –161°C to –158°C. Its primary component is methane (CH_4), and it may also contain ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and nitrogen. Impurities may include CO_2, sulfur compounds, carbonyl sulfide (COS), mercaptans, and mercury.

By reducing its volume to approximately 1/600 of that of natural gas under standard conditions (15°C, 1 atm), LNG provides a convenient means of storing and transporting gas from production sites to consumer markets worldwide.

Operation pressure

As mentioned in section *Transport form – chemical phase*, pipeline-fluid-phase will be in the following forms:

Table 25 Pipe pressures to be considered in this catalogue

Fluid	**Phase**	**Pmin/Pmax/Pdesign, barg**
H_2	Compressed gas	40/140/156 40/70/80
NH_3	Compressed liquefied gas	20/20/23
DME		13/20/23
Liquid HC	Liquid	3/8/10

A max operating pressure of 140 barg have been used in this catalogue. When building new network, 140 barg is believed to be the optimal pressure as this will give the largest buffer/storage capacity. Pressure above have not been selected as this will impose higher risk of hydrogen embrittlement. As major part of the existing natural gas net is designed to 80 barg, 70 barg has also been used in calculations as part of the natural gas transmission net can be converted to hydrogen transmission net.

Converting NG pipes to H_2 pipes

It is possible to use existing NG grid for hydrogen, though with some modifications [1][2].

Gasunie have realized a hydrogen backbone pipeline infrastructure in the Netherlands by converting NG pipes to H_2 pipelines.

Within [6], the cost of converting existing NG-transmission pipes to H_2-transmission has been assumed to be equal to 1/3 of cost of new installation.

In Vietnam, it is currently at research/development phase in regards to mixing hydrogen into natural gas and taking advantage of existing infrastructure for transportation by pipeline.

Underground pipeline

Pipelines should to the extent possible be underground as:

1. Mitigation of risk: Underground installation reduces the likelihood of damage/vandalism and the risk of explosion in in case of leakage.
2. Temperature is less variable: This reduces the expansion and shrinkage of the construction material.
3. Underground pipelines do not disfigure the nature and are less prone to protest.

Key requirements to underground piping:

1. Connections: To minimize the possibility of leaks, all underground connections should be welded.
2. Cathodic protection: To eliminate damage caused by lighting, underground pipes must be electric isolated from above ground installations via isolating flanges.
3. Corrosion: Galvanic corrosion is caused by difference in electric potential between the pipe and the soil. External coating, electrical measures (i.e. sacrificial anode or impressed current) that mitigate galvanic corrosion if there are coating-defects, and monitoring of the corrosion protection system is a must.
4. Pipe casings/load shields where above ground loading can occur (i.e. railroad, etc.).
5. Underground pipelines should be clearly marked, consider accidents caused by excavation of existing pipes.

Aboveground pipeline

Most equipment (fiscal metering, compressor/pumping stations, etc.) will normally be aboveground installations.

Key requirements to aboveground piping:

1. Connections: Generally, flanged (bolted and non-welded) connection is used above ground. However, as hydrogen is more prone to leakage, welded connections should be considered whenever practical.
2. Cathodic protection: All above ground piping shall have electrical continuity across all connections, except insulated flanges, and shall be earthed at suitable intervals to protect against lighting and static electricity.
3. Corrosion: Coating is normally applied to minimize environment corrosion. The type and amount depend on location.

Main components

Major elements in a transmission net are (see Figure 28):

1. **Filling pump/compressor:** A filling station is needed to raise the pressure from the outlet pressure of the production unit to the pressure within the transmission net.
2. **Boosting pump/compressor:** Boosting the pressure along the route to overcome friction loss is needed when the pressure drops below the minimum operating pressure.
3. **Isolation valve/vent station:** To seal off segments in case of leakage. The allowable distance between isolation valves will depend on a risk assessment of each section. In populated areas isolation valves are expected more frequently than in rural areas. Typical distance between isolation valves onshore is 10-20 km. Within this catalogue, isolation/vent station for every 20 km have been assumed.
4. **Fiscal metering stations (M/R):** two independent fiscal metering stations will most likely be installed after the filling station.

5. **Cathodic protection:** Cathodic protection is included as per shown in Figure 28 (green box with CP), i.e. one for filling station, two for each isolation valve/vent station and two for each boosting station.
6. **Scraper traps:** To maintain/clean the pipeline, a scraper lancer and a scraper receiver is needed (or a valve arrangement will allow for connection of mobile lancer and receivers) in either ends of the pipe.

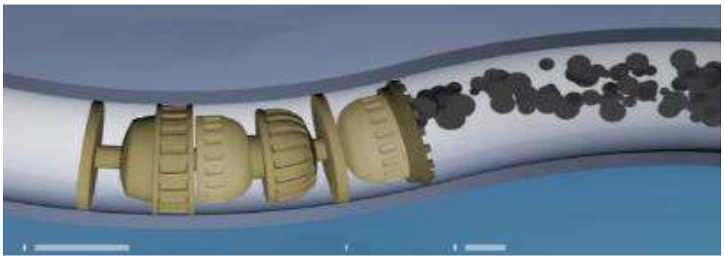


Figure 27: Scraper (also called pig) used to clean/inspect a pipeline

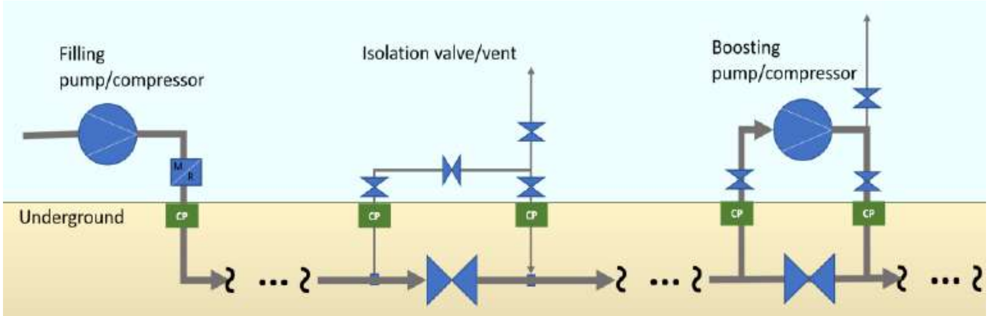


Figure 28: Major elements in a transmission pipe net

Filling compressor, fiscal metering station and scraper traps are installations required at the inlet (and/or outlet) or the pipe. Therefore, these costs have not been included in the "cost per km" estimate.

Input

Input is fluid at operation pressure given in Table 25. The flow is given by the optimal pressure drop and velocities listed in Table 26.

Output

The output is the same as the input. The exception is pressure, which can be somewhere between the min and the max pressure allowed in the transmission net.

Energy balance

The energy balance of a pipeline transportation system for gaseous and liquid fuels is determined by comparing the energy consumed for pumping, compression, and system operation with the energy content of the fuel delivered to the point of use.

Efficiency and losses

Energy loss occurs as a result of fluid frictional loss (pressure drop) in the pipelines. The friction loss is a strong function of fluid velocity. Thus, the optimal design velocity is a trade-off between capital cost (pipeline diameter) and operating cost (pumping/compression energy).

For this technology catalogue, a cost optimization has been performed. The dP/dL (dP/dL=pressure drop per km) listed in Table 26 give a good trade-off between CAPEX and OPEX (both for operating pressures at 70 bar as well as for operating pressures at 140 bar). The optimum depends on the length of the pipe and the cost of the booster vs cost of the piping material.

Table 26: Optimal/max pressure drop per km (dP/dL, bar/km), Q=duty transported in MW

	dP/dL, bar/km	**Velocity, m/s**
H_2	dP/dL(max) ≈$1.28 \times Q^{-0.75}$	P=140 bar V ≈ $4.4 \times Q^{0.1}$
		P=70 bar V ≈ $6.7 \times Q^{0.1}$
Liquid fluids (NH_3, DME, LHC)	dP/dL(max)=0.04 bar/km	

Application potential

H_2: Hydrogen is a key component that is required for optimal production of any synthetic fuel. This includes any CCU process, NH_3 production, fuel production from residue biomass/waste (the efficiency converting residue biomass/waste to synthetic fuel can be almost doubled by adding hydrogen) and H_2 fueling stations.

NH_3, DME and LHC: As these are not the "base" element, i.e. the element that is needed for production of all other fuels, and as they are much easier to transport in larger quantities via mobile transportation, pipelines will most likely just be point to point solutions where larger capacities need to be transported.

Typical capacities

The capacities considered in this catalogue are listed in the following table:

Table 27: Capacities considered in this catalogue. To convert the energy flow into LHV based flow, multiply with 120/142=0.85.

Fluid	**Mass flow TPD**	**Energy flow MW (HHV)**	**DN inch**	**Pmax barg**	**T °C**
H_2	40-13000	80-20000	4-48	140	Amb.
	40-9000	80-15000	4-48	70	
NH_3	50-10000	10-2600	4-24	20	
DME		20-3700	4-24	20	
Toluene		20-5000	4-24	10	

It is assumed that the transmission piping is underground piping and for underground piping 4" is selected as a minimum pipe-size. Therefore, for very low capacity, the pipes become quite expensive per unit capacity.

Advantages/disadvantages

Advantages:

- High energy efficiency, continuous transport, and low losses per unit of fuel.
- Safe and stable operation, with minimal dependence on weather conditions, traffic, or operational labor.
- Low environmental impact during operation due to the closed system, reducing emissions and leakage risks.

Disadvantages:

- High initial capital investment, especially for long-distance routes or complex terrain.
- Limited flexibility, with difficulty in modifying routes or capacity after construction.

Space requirements

Fuel pipeline transportation systems require the establishment of a dedicated right-of-way along the entire pipeline length to ensure safe operation, maintenance access, and incident prevention. The primary land occupation consists of the pipeline protection corridor, as well as areas allocated for pumping stations, compressor stations, block valve stations, and auxiliary facilities. Route selection should minimize passage through residential areas, environmentally sensitive zones, and valuable land resources, while ensuring compliance with applicable safety distance regulations and technical standards.

Environment

The construction phase of a pipeline may have environmental impact depending on the chosen route. An environmental impact assessment will be required.

Once the pipeline is constructed it will only have marginal environmental impact.

Blow down of pipeline sections for maintenance or repair work will be rare and done in a slow and controlled manner that will have insignificant environmental impact.

Research and development

Transmission and distribution pipes for both H_2, NH_3, DME and non-corrosive liquid hydrocarbons is a well-known technology (TRL=8-9).

Improvements and associated cost reduction:

1. Hydrogen compression:
    - Increase the suction pressure.
    - Several interstage compressors that are optimized so only compressing to the actual discharge pressure.
2. Material of construction:
    - Challenge existing assumptions such as reviewing the limitation on hardness or the belief that higher grades of pipeline steel will be more susceptible to hydrogen embrittlement.
    - Approval of newer low alloy steels for H_2 services: It is judged that there is room for larger cost reduction due to improved materials [8].
    - Plastic pipes may especially be optimal for smaller distribution pipes.
3. Max operating pressure:
    - Cost calculation within this report shows that the cost advantages of increasing the pressure is limited. However, this will most likely change if stronger alloys are approved for hydrogen service.
4. Design code:
    - Standardisation and development of Eurocodes for hydrogen pipes (i.e. CEN 234 working group or EIGA)
    - At the present, Vietnam still does not have a separate technical standard dedicated to the construction and development of hydrogen pipelines. However, regulations for fixed gas pipelines made of metal are being applied, such as QCVN 01:2016/BCT or QCVN 20:2023/BCT.
5. Installation cost:
    - Position drilling might reduce installation cost substantially: Directional drilling makes pipelines that cross streams, existing constructions, etc. much cheaper, especially in industrial/urban areas.
    - Converting NG pipes to H_2 pipes will result in a major reduction in CAPEX.
    - Put a smaller H_2 pipeline into an existing NG pipeline.

Examples of current projects

Existing natural gas pipelines in Vietnam

Vietnam's main gas supply systems are currently concentrated mainly in the South, including the Cuu Long gas system, the Nam Con Son gas system and the PM_3-Ca Mau gas system. These systems mainly meet the gas demand of gas-electricity and gas-electricity-fertilizer clusters in the Southeast and Southwest regions.

- Cuu Long pipeline system: Gas pipeline system with a total length of about 200 km, design capacity of 2 billion m^3 of gas/year, connecting the Cuu Long tank to the shore, treating gas at Dinh Co gas treatment plant, bringing gas to households in Ba Ria – Vung Tau, Dong Nai, Ho Chi Minh City, Phu My Gas Distribution Center.
- The Nam Con Son 1 gas pipeline system (370 km) and Nam Con Son 2 (320 km offshore pipeline) have a design capacity of 7 billion m^3 of gas per year per pipeline, connecting the Nam Con Son

gas fields to shore. The gas is processed at the Nam Con Son Gas Processing Plant and Dinh Co Gas Processing Plant, supplying gas to consumers in Phu My and Nhon Trach.

- PM_3 – Ca Mau gas pipeline system: Gas pipeline system with a total length of 325 km, a design capacity of 2 billion m^3 of gas/year, connecting from the Malay – Tho Chu tank to Ca Mau.
- Thai Binh pipeline system: Gas pipeline system which is 25 km long, with a design capacity of 500 million m^3 of gas/year, connecting Thai Binh mine to industrial consumers in Thai Binh and neighboring provinces.

Prediction of performance and costs

Investment cost (CAPEX)

The investment cost for fuel-transport pipelines in Viet Nam represents the full set of capital expenditures required to develop and commission an operational natural gas transmission system capable of supplying regasified LNG to power plants. These costs encompass the procurement of materials, execution of civil and mechanical works, acquisition of land and permitting approvals, and engineering and project-management activities. In practice, CAPEX for Vietnamese gas pipelines reflects a construction environment characterised by diverse terrain, stringent safety requirements, and comparatively high right-of-way compensation.

Components of investment cost

The major CAPEX elements include:

- Pipeline materials: carbon-steel line pipes manufactured to API 5L B/X42/X52 standards, together with associated fittings, block valves, instrumentation, and corrosion-protection systems.
- Construction works: trench excavation, pipe stringing, welding, non-destructive testing, hydrostatic testing, backfilling, and reinstatement undertaken in accordance with Vietnamese gas-transmission norms.
- Crossing solutions: controlled drilling or directional boring for road, railway, and river crossings — an increasingly significant cost driver in densely developed areas.
- Permitting and land acquisition: compensation for right-of-way, resettlement where applicable, environmental approvals, and compliance with provincial-level land-use regulations.
- Engineering and project management: detailed design, supervision, HSE management, quality assurance, commissioning, and contingency provisions following Vietnamese EPC practices.

Technical and design assumptions

Pipeline design parameters are aligned with current Vietnamese gas-transmission practices:

- PE or FBE external coating suitable for local soil conditions and protection requirements;
- Hydraulic design based on Vietnamese gas-transport standards for allowable pressure drop, operating pressure, and design pressure;
- Cathodic protection and integrity-management systems consistent with EPC norms used for LNG and gas pipelines;
- Compressor or booster stations included at spacing intervals typical for Vietnamese operating conditions;
- Sectionalisation valves (ESD) installed to facilitate isolation and maintenance activities;
- Installation costs reflecting local terrain constraints, higher land-acquisition costs, and elevated labour intensity relative to markets where mechanisation is more widespread.

Representative investment cost — calculation method

In the catalogue, the investment cost is expressed in USD per ton of natural gas transported (USD/tonNG). It is derived from the standard tariff-based conversion approach:

$$\text{Investment cost (USD/tonNG)}=\text{Investment tariff (USD/MMBTu)}\text{x}\mathrm{LHV}_{NG}$$

with:

$$\mathrm{LHV}_{NG}\approx 52 \text{ MMBtu per ton NG}$$

The investment tariff (USD/MMBtu) corresponds to the CAPEX-recovery component of domestic Vietnamese pipeline-transport charges, as documented in LNG-to-power supply studies and recent investment assessments. Applying the formula with Vietnamese project data yields the representative value adopted in the datasheet.

Cost-development trajectories

International evidence and Vietnamese construction practice both indicate that real-term CAPEX reductions for pipelines are incremental rather than dramatic. Accordingly, three cost-development trajectories are applied:

- Conservative (0%/year): costs are assumed to remain stable as material prices and construction costs exhibit limited real-term declines.
- Moderate (–2%/year): gradual improvements arise from optimisation of design, procurement, scheduling, and construction logistics.
- Aggressive (–5%/year): more substantial reductions could occur through adoption of enhanced construction methods, greater standardisation, improved contracting models, and economies of scale.

These trajectories ensure that projected CAPEX pathways remain consistent with Vietnamese construction realities and the broader behaviour of mature pipeline industries.

Fixed O&M

Fixed operating and maintenance (O&M) costs represent expenses that occur irrespective of throughput volume and are required to maintain safe, reliable operation of the pipeline system. These include staffing, inspections, maintenance of compressor stations, corrosion monitoring, integrity management and right-of-way maintenance.

Cost components

Typical fixed O&M activities include:

- Routine mechanical and electrical maintenance at compressor or booster stations;
- Inspection and upkeep of anti-corrosion systems, including external coatings and cathodic protection;
- Valve, sensor, and instrumentation calibration and repair;
- Surveillance of the pipeline right-of-way, including response to erosion, flooding, or encroachments;
- Periodic non-destructive testing and integrity assessments.

Representative fixed O&M cost — calculation method

Fixed O&M is calculated using an internationally recognised engineering ratio applied by AFRY for LNG and gas infrastructure:

$$\text{Fixed O\&M} = 5.72\% \times (\text{Construction cost} + \text{Equipment cost})$$

where construction and equipment together account for approximately:

$$\text{Construction} + \text{Equipment} \approx 70\% \text{ of total CAPEX}$$

The fixed O&M tariff (USD/MMBtu) is converted into the catalogue unit using:

$$\text{Fixed O\&M (USD/tonNG/year)} = \text{O\&M tariff (USD/MMBtu)} \times LHV_{NG}$$

with

$$LHV_{NG} \approx 52 \text{ MMBtu/tonNG}$$

Applying these formulas with Vietnamese pipeline data and the referenced sources yields the fixed O&M value presented in the datasheet.

Development trajectories for fixed O&M

Given the labour- and inspection-intensive nature of pipeline operations, O&M cost reductions tend to be modest:

- Conservative (0%/year): stable requirements for inspection, staffing, and routine maintenance;
- Moderate (–1%/year): incremental gains from optimised maintenance planning, improved asset-condition assessment, and more efficient service contracts;
- Aggressive (–3%/year): deeper reductions from digitalisation, automation, predictive maintenance, and advanced monitoring systems.

Under the Moderate trajectory, fixed O&M decreases gradually as Vietnamese operators adopt more structured and technologically supported maintenance processes.

Variable operational cost

Variable operational costs are minimal for natural gas pipelines, as they primarily relate to fuel or electricity used for recompression to offset frictional losses. Since the corresponding datasheet for Viet Nam does not define a variable-cost parameter, the component is acknowledged but not quantified here. Its exclusion is consistent with catalogue practice for infrastructure systems where throughput-related energy use is marginal relative to fixed O&M.

Uncertainty

Uncertainty in pipeline-transport cost estimates arises primarily from factors affecting material costs, construction effort, and permitting.
Material cost variability: steel prices, coating systems, and specialised fittings represent a major cost share and are subject to international price volatility.

- Terrain and geotechnical conditions: variations in soil type, watercourses, and elevation significantly influence construction effort and cost.
- Land acquisition and right-of-way risks: negotiation duration, compensation requirements, and local administrative processes are major sources of upward cost uncertainty.
- Construction-method variability: directional drilling, river crossings, and urban construction introduce cost variability and schedule risk.
- Regulatory and permitting uncertainty: environmental approvals, safety requirements, and compliance processes may evolve, impacting both cost and timeline.

As pipeline technology is mature, structural underestimation is limited. However, upward uncertainty remains higher than downward due to the potential for unplanned geotechnical challenges, protracted permitting, or community-objection processes. Cost-reduction potential is constrained by the physical and labour-intensive nature of pipeline installation, though incremental improvements may arise from enhanced construction technologies and better project-management techniques.

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Data sheet

Transport of H_2 by pipeline - 70 bar										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**	-	-
Energy/technical data										
Energy losses, pipelines 1-100 MW	%/1000 km	9.7%	9.3%	8.3%	7.9%	16.0%	7.3%	13.6%	A	1
Energy losses, pipelines 100-250 MW	%/1000 km	7.9%	7.6%	6.8%	6.4%	13.1%	6.0%	11.2%	A	1
Energy losses, pipelines 250-500 MW	%/1000 km	6.1%	5.8%	5.2%	4.9%	10.1%	4.6%	8.6%	A	1
Energy losses, pipelines 500-1500 MW	%/1000 km	4.3%	4.1%	3.7%	3.4%	7.1%	3.2%	6.1%	A	1
Energy losses, pipelines 1500-5000 MW	%/1000 km	2.8%	2.7%	2.4%	2.3%	4.7%	2.1%	4.0%	A	1
Energy losses, pipelines 5000-20000 MW	%/1000 km	2.1%	2.0%	1.8%	1.7%	3.5%	1.6%	3.0%	A	1
Energy losses, pipelines above 20000 MW	%/1000 km	1.6%	1.5%	1.3%	1.3%	2.6%	1.1%	2.1%	A	1
Energy demand, compressor filling station	%	0.9%	0.8%	0.7%	0.7%	3.0%	0.6%	2.1%	B	1
Technical life time	years	50	50	50	45	55	45	55		1
Construction time	years	1	1	1	0.5	2	0.5	2		1
Economic data										
Investment costs; 0-100 MW	USD/MW/m	5.3	5.2	4.9	4.9	6.9	4.5	6.3	C, F	1
Investment costs; 100-250 MW	USD/MW/m	2.4	2.3	2.2	2.2	3.0	2.0	2.7	C, F	1
Investment costs; 250-500 MW	USD/MW/m	1.4	1.4	1.4	1.4	1.9	1.3	1.7	C, F	1
Investment costs; 500-1000 MW	USD/MW/m	1.0	1.0	1.0	1.0	1.3	0.9	1.2	C, F	1
Investment costs; 1000-4000 MW	USD/MW/m	0.6	0.6	0.6	0.6	0.7	0.6	0.6	C, F	1
Investment costs; above 6000 MW	USD/MW/m	0.3	0.3	0.3	0.3	0.3	0.3	0.3	C, F	1
Investments, installation	%	77.5%	77.5%	77.5%	75%	80%	70%	80%	D	1
Investments, materials	%	22.5%	22.5%	22.5%	20%	25%	20%	30%	D	1
Fixed O&M	USD/km/year/MW	0.5	0.36	0.3	0.3	1.4	0.2	1.4	E	1
Variable O&M	USD/MW/km	-	-	-	-	-	-	-		1

Notes:

A Energy required to overcome pipeline pressure drop (dP). Optimal dP/km depend on cost of booster compressor vs pipe material cost. Currently, the optimum seems to be: Velocity (m/s) ≈ $4.4 \cdot Q^{0.1}$, dPdL(bar/km) ≈ $1.28 \cdot Q^{-0.75}$, Q = energy flow (MW).

B Energy to compress from 35 barg to 140 barg. This value can be lowered by only compressing to current operation pressure in transmission line using outtake from interstage compressors.

C Estimate includes: Installation based on buried pipeline with 8% tunneling, coating, sectionalization with depressurizations vents for every 20 km, cathodic protection, coating, pressure boosting stations, permitting and landowner compensation.

D Installation cost is ~80% for small pipes and ~75% for large pipes.

E Fixed operation cost is per pipe length and capacity. 4% of CAPEX is assumed in 2020, 2% in 2030 and 1.5% in 2050.

F This parameter refers to single-line pipelines.

References

1 Danish Energy Agency, 2025 - Technology Data for Energy Transport

Transport of H_2 by pipeline - 140 bar										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data										
Energy losses, pipelines 1-100 MW	%/1000 km	7.5%	7.0%	6.3%	6.0%	12.1%	5.5%	10.3%	A	1
Energy losses, pipelines 100-250 MW	%/1000 km	6.4%	5.9%	5.3%	5.0%	10.2%	4.6%	8.7%	A	1
Energy losses, pipelines 250-500 MW	%/1000 km	5.1%	4.7%	4.2%	3.9%	8.1%	3.7%	6.9%	A	1
Energy losses, pipelines 500-1500 MW	%/1000 km	3.8%	3.5%	3.1%	3.0%	6.1%	2.7%	5.2%	A	1
Energy losses, pipelines 1500-5000 MW	%/1000 km	2.7%	2.5%	2.2%	2.1%	4.2%	1.9%	3.6%	A	1
Energy losses, pipelines 5000-20000 MW	%/1000 km	2.1%	1.9%	1.7%	1.6%	3.3%	1.5%	2.8%	A	1
Energy losses, pipelines above 20000 MW	%/1000 km	1.5%	1.4%	1.3%	1.3%	2.5%	1.1%	2.1%	A	1
Energy demand, compressor filling station	%	2.1%	1.7%	1.5%	1.3%	3.5%	0.9%	2.5%	B	1
Technical life time	years	50	50	50	45	55	45	55		1
Construction time	years	1	1	1	0.5	2	0.5	2		1
Economic data										
Investment costs; 0-100 MW	USD/MW/m	5.8	5.6	5.3	5.3	7.5	4.8	6.8	C, F	1
Investment costs; 100-250 MW	USD/MW/m	2.5	2.4	2.3	2.3	3.3	2.2	3.0	C, F	1
Investment costs; 250-500 MW	USD/MW/m	1.6	1.6	1.4	1.4	2.0	1.3	1.9	C, F	1
Investment costs; 500-1000 MW	USD/MW/m	1.1	1.0	1.0	1.0	1.3	0.9	1.3	C, F	1
Investment costs; 1000-4000 MW	USD/MW/m	0.6	0.6	0.6	0.6	0.7	0.6	0.7	C, F	1
Investment costs; above 6000 MW	USD/MW/m	0.3	0.3	0.3	0.3	0.3	0.3	0.3	C, F	1
Investments, percentage installation	%	77.5%	77.5%	77.5%	75%	80%	70%	80%	D	1
Investments, percentage materials	%	22.5%	22.5%	22.5%	20%	25%	20%	30%	D	1
Fixed O&M	USD/km/year/MW	0.5	0.36	0.3	0.3	1.4	0.2	1.4	E	1
Variable O&M	USD/MW/km	0	0	0	0	0	0	0		1

Notes:

A Energy required to overcome pipeline pressure drop (dP). Optimal dP/km depend on cost of booster compressor vs pipe material cost. Currently, the optimum seems to be: Velocity (m/s) ≈ $4.4*Q^{0.1}$, dPdL(bar/km) ≈ $1.28*Q^{-0.75}$, Q = energy flow (MW).

B Energy to compress from 35 barg to 140 barg. This value can be lowered by only compressing to current operation pressure in transmission line using outtake from interstage compressors.

C Estimate includes: Installation based on buried pipeline with 8% tunneling, coating, sectionalization with depressurizations vents for every 20 km, cathodic protection, coating, pressure boosting stations, permitting and landowner compensation.

D Installation cost is ~80% for small pipes and ~75% for large pipes.

E Fixed operation cost is per pipe length and capacity. 4% of CAPEX is assumed in 2020, 2% in 2030 and 1.5% in 2050.

F This parameter refers to single-line pipelines.

References

1 Danish Energy Agency, 2025 - Technology Data for Energy Transport

Transport of NH_3 by pipeline

Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
					Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data										
Energy losses	‰	<0.1‰	<0.1‰	<0.1‰	0.01‰	0.1‰	0.01‰	0.1‰	A, B	1
Technical life time	years	50	50	50	45	55	45	55		1
Construction time	years	1	1	1	0.5	2	0.5	2		1
Economic data										
Investment costs; 1-15 MW	USD/MW/m	14.6	13.8	13.3	13.08	21.80	11.94	18.57	B, C, F	1
Investment costs; 15-30 MW	USD/MW/m	9.7	9.2	8.8	8.69	14.48	7.93	12.34	B, C, F	1
Investment costs; 30-100 MW	USD/MW/m	4.0	3.9	3.6	3.61	6.01	3.29	5.13	B, C, F	1
Investment costs; 100-300 MW	USD/MW/m	1.9	1.7	1.7	1.65	2.74	1.50	2.34	B, C, F	1
Investment costs; 300-500 MW	USD/MW/m	1.0	1.0	1.0	0.95	1.58	0.86	1.34	B, C, F	1
Investment costs; 500-1000 MW	USD/MW/m	0.6	0.6	0.6	0.57	0.95	0.52	0.81	B, C, F	1
Investment costs; 1000-2000 MW	USD/MW/m	0.4	0.3	0.3	0.33	0.55	0.30	0.47	B, C, F	1
Investment costs; above 2000 MW	USD/MW/m	0.3	0.3	0.3	0.26	0.43	0.24	0.37	B, C, F	1
Investments, installation	%	87.0%	82.7%	78.3%	80.0%	90.0%	75.0%	90.0%	D	1
Investments, materials	%	13.0%	17.4%	21.7%	10.0%	20.0%	10.0%	25.0%	C	1
Fixed O&M	USD/km/year /MW	144	144	144	72	288	72	288	E	1
Variable O&M	USD/MW/km	-	-	-	-	-	-	-		1

Notes:

A	Energy required to overcome pipeline pressure drop (dP). Optimal dP/km depend on cost of booster compressor vs pipe material cost. Currently, the optimum seems to be: Velocity (m/s) ≈ $4.4*Q^{0.1}$, dPdL(bar/km) ≈ $1.28*Q^{-0.75}$, Q = energy flow (MW).
B	Energy to compress from 35 barg to 140 barg. This value can be lowered by only compressing to current operation pressure in transmission line using outtake from interstage compressors.
C	Estimate includes: Installation based on buried pipeline with 8% tunneling, coating, sectionalization with depressurizations vents for every 20 km, cathodic protection, coating, pressure boosting stations, permitting and landowner compensation.
D	Installation cost is ~80% for small pipes and ~75% for large pipes.
E	Fixed operation cost is per pipe length and capacity. 4% of CAPEX is assumed in 2020, 2% in 2030 and 1.5% in 2050.
F	This parameter refers to single-line pipelines.

References

1 Danish Energy Agency, 2025 - Technology Data for Energy Transport

Transport of natural gas by pipeline										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**		
Economic data										
NG: Investment cost	USD/tonNG	1.04	0.94	0.63	0.80	1.04	0.34	0.94	A, C, D	1, 2, 3, 4, 5, 6
NG: Fixed O&M cost	USD/tonNG/y	0.24	0.23	0.19	0.21	0.24	0.12	0.23	B, C, D	1, 2, 3, 4, 5, 6

Notes:

A Pipeline tariff is about 0.025 USD/tr.BTU based on Vietnamese LNG pipeline assessments.
B Fixed O&M assumption is 5.72% of construction and equipment cost. Construction and equipment cost is about 70% of CAPEX.
C Tariff decomposition into investment (0.020 USD/tr.BTU) and fixed O&M (0.0046 USD/tr.BTU).
D LNG heating value: 1 ton is 52 million BTU.

References

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2.2. Transportation of gas and liquid fuel by ship

Brief technology description

NH_3

LNG

LH_2 (future)

Ship and tank types

For ship transport, only liquid transport exist, most likely because gas is not economically favourable due to low volumetric energy density and require a very high vessel wall thickness. Thus, only moderate pressure levels (<20 bar) exist, i.e. it is not possible to transport H_2 and NG as compressed gases. However, there exist development projects that look at marine transport of CNG [1] and marine transport of LH_2 [2].

Liquid/gas transporting ships can be divided into the following types:

Table 28: Different types of tankers for liquid/gas transport

Fluid	**Tank types (fluid phase)**	**T, °C**	**P, barg**	**Tank Class**	**Capacity (typical), m^3**	**Number of ships today (unit)**	**CAPEX M€**
LHC	Oil tankers (LHC)	Amb.	Atm.	Integral	3,000-120,000	800	31[21] (50,000 m^3)
LPG DME NH_3[22]	Full refrigerated (refrigerated liquefied gas)	-48 -25	Atm. Atm.	A C	15,000-200,000 6,000–12,000	Almost 300 <50	79[23] (80,000 m^3) 60–70 (≈10,000 m^3)
	Semi-refrigerated (refrigerated + comp. liquefied gas)	-10	4-17	C	6,000-12,000	Almost 100	65–75 (≈10,000 m^3)
	Pressurized (compressed liquefied gas)	Amb	≥17[24]	C	1,000-3,000	300	15–25 (≈2,000 m^3)
LNG	Cryogenic cooling	-165	Atm.	A, B, M	40,000 – 135,000	500	155[25] (145,000 m^3)
LH_2[26]	Cryogenic cooling	-253	Atm.		1,250	1 (expected in end of 2020)	90–110 (≈1,250 m^3)

The tanks can be either integral part of the ship structure or an independent self-supported tank. The independent tanks can be divided into:

1. Class A tanks – prismatic free-standing tanks: Pd< 700 mbar g.
2. Class B tanks – spherical shape: Pd< 700 mbar g.
3. Class C tanks – cylindrical or bilobe shape: Pd> 2 bar g
4. Membrane tanks (M)

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[21] BRS group annual review 2019

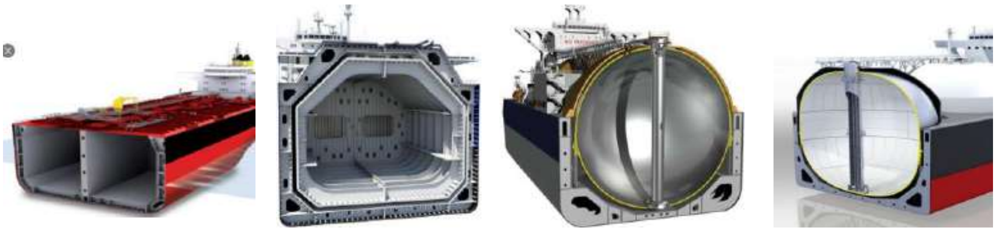
[22] Other fluids that can be transported via LPG tankers: Ethylene (full and semi refrigerated), Propane, Butane and Propylene.

[23] https://www.seatrade-maritime.com/tankers/euronav-buys-another-scrubber-fitted-resale-vlcc-newbuild

[24] Correspond to vapor pressure of LPG at ~45°C.

[25] Danish Ship Finance, Shipping market review 2019

[26] https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487



Integral tank Class A: prismatic Class B: spherical Class C: cylindrical

Figure 29: Different tank classes. The most cost-efficient onboard storage of ammonia seems to be class C (pressurized tanks) [3]

Max sizes of ships are given by the following classes:

Table 29: Tanker size classes

Max size class	Max Length m	Max Beam m	Max Draft m	Max dead weight ton (DWT)	Application/info
Coastal Tanker	205 m	29 m	16 m	50,000	Mainly used for refined products; domestic routes (Hai Phong – Dung Quat – Vung Ang).
Aframax	245 m	34 m	20 m	80,000	AFRA (Average Freight Rate Assessment) Typical for LNG import terminals (Vung Ang, Nghi Son); aligns with Hai Lang FSRUs.
Suezmax	285 m	45 m	23 m	125,000-180,000	Originally the max. capacity of the Suez Canal; common for Hai Lang LNG and Quảng Trị deep-sea ports.
Very large crude carrier (VLCC)	330 m	55 m	28 m	320,000	Oil tankers; not typical for Vietnam LNG ports due to draft limits.
Ultra large crude carrier (ULCC)	415 m	63 m	35 m	550,000	Oil tankers; not applicable for current VN infrastructure.

There are various technologies for developing LNG import infrastructure. Onshore LNG terminals are the most common option due to their stability and safety in both construction and operation. However, at locations where geological conditions, terrain, shipping channels, or environmental requirements are not suitable, offshore floating storage solutions will be considered. Two technologies will be studied and proposed for projects in Vietnam, including:

- Onshore LNG terminal: including unloading systems, storage tanks, technological equipment for LNG regasification, auxiliary systems, and other infrastructure;
- Floating Storage and Regasification Unit (FSRU): options include either building a new FSRU vessel or converting LNG carriers, along with regasification modules, mooring solutions, and LNG transportation.

Reliquification onboard

The semi-pressurized and fully refrigerated carriers can be provided with reliquification which re-liquify any boil-off produced during loading and operation and return it to the tanks.

Main components

At present, the primary mode of LNG transportation is by dedicated LNG carriers, with capacities ranging from 155,000 m³ to 260,000 m³, of which vessels between 155,000 m³ and 170,000 m³ are the most common.

Some key components of an LNG carrier system include:

- Insulated cargo containment system: Maintains LNG at cryogenic temperatures of approximately –162°C. This system typically employs either membrane or spherical tank technology, equipped with thick insulation layers to prevent heat ingress that could cause boil-off and to protect the steel hull from brittle fracture.

- Boil-off Gas (BOG) compression and handling system: Collects natural gas that evaporates from the cargo tanks. The system stabilizes tank pressure and then compresses the gas for use as engine fuel or safely disposes of it through controlled combustion.

- Submerged cargo pumps: Fully immersed in the LNG at the bottom of the tanks. These pumps transfer cargo ashore during unloading. Their submerged configuration allows for self-cooling and eliminates the risk of spark formation that could cause ignition.

- Dual-fuel engines: Enable the vessel to operate on both diesel oil and boil-off gas from the cargo tanks. This feature enhances fuel efficiency and significantly reduces emissions.

- Emergency shutdown (ESD) system: A critical safety mechanism for gas transport. When sensors detect leakage, fire, or abnormal pressure, the system automatically closes all cargo valves and stops pumping operations within seconds to isolate the hazard.

Upon arrival at the consumption site, LNG is regasified through vaporization equipment and then injected into the gas pipeline network for delivery to end-users. For households located far from pipeline networks, coastal areas, and offshore islands in LNG-importing countries, LNG can be transported by tanker trucks, rail, or small coastal vessels with capacities ranging from 2,500 to 12,000 m³ to receiving terminals.

Input

Input is the fluid to be transported and the fuel used to sail the ship.

Fuel to be transported:

The terminal will consist of storage tanks with capacity typically 120-150% of the ship's capacity. Loading system will normally be designed for ~10h loading. Fuel is typically loaded with loading arms or flexible hoses.

If refrigerated/cryogenic liquefied fluid, the loading system/tanks must either be precooled or loaded slow (see section *Loading/unloading*). Any generated vapor must be re-liquefied (require specific re-liquefied system) or vented (boil-off).

Fuel used to drive the ship:

Fuel consumption for propulsion is described in *Energy losses*.

Output

The output is the fluid that have been transported. Normally it will be the same input. Exception is boil-off (see section *Energy losses*).

As all ship transport is transporting liquid fuels, unloading will be via pump. The tank pressure will fall as liquid is removed. If the unloading rate is high there may be insufficient boil-off to maintain positive pressure in the tank, and blanketing gas must be added to prevent a vacuum.

Energy balance

The energy balance of gaseous and liquid fuel transportation by sea is determined by comparing the energy consumed for vessel operation, cargo handling equipment, and port infrastructure with the energy content of the fuel delivered to the receiving point.

Input energy includes fuel used for ship propulsion, electricity for pumping, compression, and regasification systems (for LNG/LPG), as well as auxiliary equipment at the port. The useful energy corresponds to the amount of fuel delivered to storage facilities or end-use plants, meeting the required specifications in terms of flow rate, pressure, and quality.

Efficiency and losses

Energy losses during the transportation with ship include fuel consumption, both to the actual transport as well as the transport back of an empty truck, and boil off (see *Energy losses*).

Application potential

Ships will be applicable for point-to-point transportation.

Ship transportation requires a certain minimum volume and distance to be economically favorable compared to the alternatives (pipeline and road transport).

Typical capacities

Typical capacities of ships are given in table below.

*Table 30: Typical capacities of tankers for liquid/gas transport. * No liquid H_2 carriers are developed, so the numbers are based on an LNG carrier*

Fluid	**Net Ship**		**Pd barg**	**Td °C**
	Mass, tons	**Energy, GW**		
LH_2	10.000*	345	Ambient	-253
NH_3	45.000	240	Ambient	-48
DME	45.000	366	Ambient	-48
Toluene	45.000	508	Ambient	Ambient

Advantages/disadvantages

Advantages:

- High economic and energy efficiency when transporting large volumes, particularly over medium and long distances.
- High flexibility in routing and sourcing, with the ability to scale capacity according to fuel demand.
- Potential to use cleaner marine fuels (such as LNG or biofuels) for vessels, contributing to reduced emissions.

Disadvantages:

- Dependent on hydrological conditions, weather, and the receiving capacity of ports/terminals.
- Requires significant investment and operating costs for port infrastructure, storage facilities, and cargo handling systems.
- Environmental risks in the event of spills or fuel leakage on water surfaces.

Space requirement

The waterborne transportation option requires the use of water surface areas and riverbank or coastal land for the construction of receiving ports/terminals, turning basins, anchorage areas, and associated technical infrastructure. Storage facilities and fuel handling systems must be located at elevations suitable to ensure safety against rising water levels, storm surges, and flooding. The development of ports, terminals, and navigation channels may alter existing land and water use patterns, particularly when adjacent to or passing through residential areas. Therefore, it is necessary to comprehensively consider maritime safety corridors, environmental protection buffer distances, and land allocation feasibility throughout the entire project lifecycle.

Environment

The environmental impact of ship transport is mainly due to the emissions from the ship doing propulsion.

Maritime transport accounts for approximately 2–3% of global CO_2 emissions [4]. Based on the Report on gas supply plan for Nhon Trach Power Center, LNG shipping to Vietnam contributes about 1.5–2.5 $MtCO_2$ per year (equivalent to 0.25–0.30 tCO_2 per ton per 1,000 km at a transport volume of 3–4 million tons/year and voyage distance of 2,000–3,000 km). This corresponds to about 2–2.5% of national transport sector emissions, consistent with the global benchmark.

The IMO's (International Maritime Organization) Marine Environment Protection Committee (MEPC) have introduced the following to measures to reduce and control the GHG emission from ships:

1. The Energy Efficiency Design Index (EEDI) which set minimum energy efficiency performance levels for new ships
2. The Ship Energy Efficiency Plan (SEEMP) which set rules for improvement of energy efficiency of both new and existing ships

Additionally, IMO/MEPC (2023 Strategy) have adopted GHG emission goals of at least 50% reduction by 050 compared to 2008, with checkpoints of –20% by 2030 and –70% by 2040. For LNG carriers, the current emission factor is ~10–15 gCO_2/MJ (≈0.25–0.30 tCO_2 per ton per 1,000 km), with potential reductions of 20–30% before 2035.

Other environmental challenges:

1. Ship recycling
2. Ballast water management
3. Hull fouling
4. Waste management

Research and development

Liquid carriers are a proven commercial technology except for LH_2. For LH_2 TRL=5 while for the other it is 9.

Much research is conducted in reducing fuel consumption by for example reducing the hull resistance by air lubrication, new designs of the bulbous bow, new hull coatings and improving propulsion.

Developing LH_2 technology for transport of liquid hydrogen by ship is ongoing.

Examples of current projects

Thi Vai LNG Project Chain: This is Viet Nam’s first LNG terminal project. LNG is transported by specialized LNG carriers from international supply sources to the Thi Vai LNG terminal, where it is regasified and supplied to gas-fired power plants in the Southeast region.

Figure 30: Image of Thi Vai LNG terminal

Prediction of performance and costs

Investment cost (CAPEX)

Ship investment costs for LH_2, L20 and LHC transport reflect the fundamentally different containment technologies, safety systems, and propulsion configurations required for each fuel. These vessels are purpose-built assets whose capital costs are largely driven by the complexity of their cargo containment systems and the safety constraints associated with hydrogen and hydrogen-derived fuels. In the Technical Catalogue, the 2025 reference CAPEX values are sourced directly from Vietnamese technical assessments, ensuring alignment with the *GIZ – Recommended Medium to Long-Term Strategy of Oil & Gas and Chemical Industries in Vietnam* and accompanying PtX transport studies.

For 2025, the representative values applied are:

- LH_2 carrier: 412 million USD per ship with capacity of 11000 tons.
- L20 carrier: 50 million USD per ship with capacity of 26000 tons,
- LHC carrier: 76 million USD per ship with capacity of 11000 tons.

These figures represent the baseline construction cost of newbuild vessels designed specifically for each cargo type. Their relative magnitudes reflect the underlying technical complexity:

- LH_2 carriers must accommodate cryogenic containment at approximately –253°C, requiring multilayer insulation, boil-off gas management, pressure-relief systems, inerting systems and extensive safety instrumentation. The engineering requirements for hull integration and thermal protection drive substantially higher capital intensity.
- L20 carriers (carrying ammonia or methanol-equivalent cargo) rely on mature tanker technologies and less extreme containment conditions, resulting in materially lower CAPEX.
- LHC carriers occupy an intermediate position, involving specialised containment for liquid organic hydrogen carriers that are less technically complex than cryogenic LH_2 systems but more demanding than conventional chemical tankers.

To support forward-looking scenario analysis, CAPEX development follows the reduction pathways embedded in the dataset:

- Conservative: 0%/year — reflecting minimal technological change and stable market conditions.
- Moderate: −3%/year — capturing gradual improvements in vessel design, procurement efficiency and partial standardisation.
- Aggressive: −6%/year — representing accelerated technological learning, larger production series and improvements in shipyard productivity as hydrogen-related shipping becomes more mainstream.

These trajectories allow cost evolution to be explored without altering the fundamental cost hierarchy between LH_2, L20 and LHC vessels.

Fixed O&M

Fixed O&M costs are not included in the ship-transport datasheet. The reason is methodological rather than technical: available Vietnamese assessments do not provide consistent, disaggregated or fuel-specific fixed-O&M values that can be applied uniformly across LH_2, L20 and LHC carriers. Instead, operational expenditures such as crewing, maintenance, insurance, periodic inspections and containment-system servicing are typically aggregated into broader cost categories or treated within route-specific operating-cost models.

Because these underlying data cannot be specialized or validated across fuel types, and to avoid introducing assumptions unsupported by Vietnamese evidence, fixed O&M is omitted entirely from the Technical Catalogue. Any recurring maintenance or operational costs must therefore be addressed in dedicated operational-cost modelling outside the scope of this specialized dataset.

Port cost

Port-handling costs constitute a major component of shipping-based transport systems and vary significantly by fuel due to the adherence to different operational, safety and handling protocols. The representative 2025 values used in the Technical Catalogue are:

- LH_2 port cost: 4,966 USD/ton H_2
- L20 port cost: 106 USD/ton H_2-equivalent
- LHC port cost: 356 USD/ton LHC

These port costs cover the full range of terminal activities including:

- Berthing, pilotage and tug assistance;
- Cargo-transfer operations using fuel-specific loading systems;
- Boil-off gas management (for LH_2 and selected LHC systems);
- Storage and safety monitoring;
- Compliance with cryogenic or hazardous-chemical handling protocols.

LH_2 incurs the highest port cost because of the exceptionally strict safety standards, specialised cryogenic transfer systems and the need for protective safety zones. L20 operations require substantially less specialised equipment, while LHC handling falls between these two extremes.

Port-cost projections follow the reduction pathways established in the dataset:

- Conservative: 0%/year — no structural change to port tariffs or operational efficiency.
- Moderate: −1%/year — incremental gains from improved scheduling, automation and routine optimisation.
- Aggressive: −3%/year — stronger reductions driven by digitalisation, standardised hydrogen-handling protocols and productivity improvements at specialised terminals.

Energy demand

Propulsion energy demand represents the energy required per kilometre of travel for each vessel type, integrating main-engine propulsion requirements with auxiliary power loads and cargo-containment demands. These values are derived from Vietnamese engineering assessments and reflect representative long-distance operating conditions for hydrogen-related shipping.

For 2025, the Technical Catalogue uses:

- LH_2 carrier: 1,487 MJ/km
- L20 carrier: 2,500 MJ/km
- LHC carrier: 3,300 MJ/km

These differences primarily reflect:

- Vessel mass and hull hydrodynamics;
- Containment-system weight and auxiliary electrical loads;
- Boil-off or circulation-system requirements (notably for LH_2 and LHC);
- Propulsion-system efficiency and typical cruising speeds.

LH_2 carriers exhibit lower per-kilometre energy demand than LHC carriers due to differences in vessel design and containment configuration, while L20 ships fall between the two. To maintain internal consistency and avoid unverified assumptions, these energy-demand values are held constant across projection years unless specifically altered for scenario-based analyses.

Uncertainty

The uncertainty related to the costs for transporting hydrogen are substantial, since hydrogen carriers has not yet been built and the cost therefore is based on cost for LNG.

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Datasheet

Transport of LH_2, L20 and LHC by ship

Parameter	Unit	2025	2030	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper	-	-
Energy/technical data										
LH_2: Energy demand	MJ/km	1,487	1,413	1,115	-	-	-	-	A, J	
L20: Energy demand	MJ/km	2,500	2,375	1,875	-	-	-	-	A, J	
LHC: Energy demand	MJ/km	3,300	3,135	2,475	-	-	-	-	A, J	
Technical life time	year	20	20	20	-	-	-	-	B	
Economic data										
LH_2: Investment cost	USD/tonH_2	37,455	44,484	97,470	43,420	46,675	80,344	107,283	C, D, E, F	1
L20: Investment cost	USD/tonL20	1,923	2,284	5,005	1,923	2,397	4,125	5,508	C, D, E, F	1
LHC: Investment cost	USD/tonLHC	6,909	8,206	17,980	6,909	8,610	14,821	19,790	C, D, E, F	1
LH_2: Fixed O&M cost	USD/tonH_2/year	-	-	-	-	-	-	-		
L20: Fixed O&M cost	USD/tonL20/year	-	-	-	-	-	-	-		
LHC: Fixed O&M cost	USD/tonLHC/year	-	-	-	-	-	-	-		
LH_2: Port cost	USD/tonH_2	4,966	4,723	3,863	4,264	4,966	2,568	4,723	G, H, I	1
L20: Port cost	USD/tonL20	106	101	82	91	106	55	101	G, H, I	1
LHC: Port cost	USD/tonLHC	356	339	277	306	356	184	339	G, H, I	1

Notes:

A	Energy demand values reflect baseline propulsion energy requirements for LH_2, L20, and LHC vessels, including relevant fuel-loss characteristics.
B	A technical lifetime of 20 years is applied consistently for all shipping assets in the transport modelling assumptions.
C	Investment cost calculated for ship capacity: (i) LH_2: 11000 tons; (ii) L20: 26000 tons; (iii) LHC: 11000 tons.
D	Base-year investment costs remain constant in the source dataset, with any future reductions applied externally for scenario modelling.
E	LH_2 ship CAPEX represents total vessel construction cost including cryogenic containment, insulation and safety systems. L20 and LHC ship CAPEX reflects representative tanker sizes and associated cargo-handling system costs.
F	Investment cost scenarios reflect stable costs under conservative conditions, moderate reductions from design and procurement optimization, and aggressive reductions linked to technological advances and shipbuilding economies of scale.
G	Port cost values represent export-side storage and handling infrastructure requirements for LH_2, L20, and LHC.
H	Port operations assume typical berthing conditions, ancillary services, and handling activities required for hydrogen carriers.
I	Port cost scenarios maintain constant fees conservatively, with moderate efficiency-driven reductions, and aggressive declines from digitalization, operational streamlining, and standardized hydrogen-handling procedures.
J	It is assumed that the efficiency of the combustion engine is improved so it is 95% in 2030 of the efficiency in 2025 and 75% in 2050. The 75% is based on the difference between the efficiency of a traditional combustion engine and a fuel cell engine. The 95% is based on natural replacement of old tankers with new tankers that have a more efficient engine (some of them might be fuel cells) and revamp of existing engines.

References

1 GIZ, “Recommended Medium to Long-Term Strategy of Oil & Gas and Chemical Industries in Vietnam”

Transport of LNG by ship										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2030)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data										
LNG: Energy demand	ton/day	108	190	1,836					B	1
Technical life time	year	20	20	20						
Economic data										
LNG: Investment cost	USD/tonLNG	537	461	251	394	537	134	461	A, B, G	1
LNG: Fixed O&M cost	USD/ton/y	-	-	-	-	-	-	-	C	
LNG: Port fee	USD/tonLNG	10.40	9.40	6.28	10.40	8.05	9.40	2.73	D, G	1
LNG: Port cost	USD/tonLNG	3.60	3.42	2.80	3.60	3.09	3.42	0.99	D, G	1
LNG: Shipping cost	USD/tonLNG	22.9	20.7	13.8	22.9	18.7	20.7	6.0	E, F, G	1

Notes:

A	Investment cost for LNG carriers remains stable in the conservative case due to limited technological change and counterbalancing inflationary pressures on steel, labor, and shipyard services.
B	Investment cost is calculated for typical ship capacity: About 80000 tons.
C	Fixed O&M costs remain constant in the conservative case because crew requirements, maintenance cycles, insurance and regulatory compliance change slowly.
D	Port fees and port costs represent aggregated port-related charges (loading, discharge, and canal fees where applicable), derived from lump-sum port charges and normalized by the amount of LNG handled per voyage to express values in USD/ton LNG, ensuring methodological consistency and direct comparability with port costs reported for other ship-based transport technologies.
E	Shipping-cost reductions (0%, 2%, 4%) reflect improvements in fuel efficiency, voyage optimization, and reduced boil-off gas losses, with aggressive cases assuming adoption of high-efficiency propulsion and advanced fleet-management systems.
F	Shipping-cost is based on cost from Russia to Vietnam.
G	Market conditions - fuel prices, charter rates, global LNG demand, inflation, and trade policies - introduce uncertainty, so all cost-reduction assumptions must be stress-tested through scenarios and sensitivity analysis.

References

1 Institute of Energy, "Feasibility study report of Hai Lang LNG project, 2025"

3. TRANSPORTATION OF COAL AND SOLID FUEL

General introduction of transportation of coal and solid fuel

Unlike liquid fuel transport, solid fuel transportation is relatively simple and can easily utilize existing infrastructure such as trucks, railways, and conventional cargo vessels. Solid fuel transport offers higher safety levels and does not require the stringent safety standards applied to gaseous fuel transport. However, dust control must be carefully managed.

This chapter introduces various solid fuel transportation methods, focusing on coal, which remains a key fuel for thermal power plants in Vietnam. Coal transportation methods (including both domestic and imported coal) include:

- Transportation by conveyor;
- Transportation by ship;
- Transportation by truck/train.

Domestic coal transportation in Vietnam

Domestic coal remains a primary input for many thermal power plants, particularly anthracite-fired plants in Northern Vietnam. Major mining areas include Quang Ninh, Thai Nguyen, and smaller mines such as Na Duong and Nong Son. The main coal types used are anthracite (the most common) and lignite, mainly serving the Na Duong Thermal Power Plant.

After extraction, coal is transported from ports/transshipment yards to power plants and end users via various modes, including coastal shipping, inland waterways (barges), railways, road transport, and conveyor belts.

Imported coal transportation

Vietnam currently imports coal from countries such as Indonesia, Australia, and Russia, benefiting from relatively favorable transport distances and large coal reserves. These exporting countries have well-developed logistics infrastructure, including ports capable of accommodating large vessels of up to 200,000 DWT. Among them, Indonesia offers the shortest shipping distance compared to other supply sources.

In recent years, coal imports from Laos to Vietnam have increased significantly, mainly through the La Lay International Border Gate (Dakrong District, Quang Tri Province – Salavan Province, Laos). To transport larger volumes of coal, the construction of a closed conveyor belt system from coal stockpiles in Laos across the border to stockyards in Vietnam has been considered an effective solution to address logistics constraints and significantly increase transport capacity. This project is currently under investment and construction.

Details will be presented in Sections 3.1, 3.2, and 3.3.

Transportation of metal fuel

In addition, the general introduction briefly presents transportation methods for other solid fuels such as iron, copper, and aluminum. These materials can be collectively referred to as metallic fuels and are considered a potential future energy storage solution. The principle is based on a reversible chemical cycle: surplus electricity in summer is used to reduce metal oxides into pure metals, which act as very high energy-density and safe energy carriers. When needed, these metals react in a controlled manner with water, releasing useful heat and hydrogen; the hydrogen is then converted back into electricity.

Metallic fuels are typically transported in the form of metal powder or granules. These materials can be safely stored and transported at ambient temperature and atmospheric pressure, without the need for expensive pressure vessels or cryogenic cooling. Safety requirements are similar to those for conventional bulk materials. The explosion risk of fine metal dust can be mitigated by using larger granules.

Therefore, similar to coal, metallic fuels can be transported using trucks, freight trains, and conventional cargo ships. The specific transport modes considered include:

- Maritime transport: Using bulk carriers or standard container ships. Solid metals are extremely stable and do not pose leakage or high fire/explosion risks like liquid fuels, thereby reducing insurance costs and the need for specialized equipment.

- Rail transport: An optimal method for transporting large volumes of metal powder from recycling plants or mines to energy hubs. Iron powder can be stored in sealed specialized railcars to prevent dust dispersion and moisture ingress.

- Truck transport: Suitable for short distances, supplying fuel directly to industrial plants or local energy stations.

In the future, metallic fuels are expected to become a promising energy storage solution due to their favorable transport characteristics. However, this technology is currently still at the research and pilot stage, with very few projects deployed at commercial scale. Therefore, information related to metallic fuel transportation will continue to be updated in future editions of the technology handbook as more comprehensive data and practical experience become available.

3.1. Transportation of coal fuel by conveyor

Brief technology description

Coal transportation by conveyor belt is a continuous mechanized solution widely used in coal mines, coal ports, and thermal power plant areas to transport bulk coal over short, medium, and long distances. After extraction or receipt, coal is fed onto the conveyor via a loading hopper. The conveyor moves continuously by means of a drive pulley system and electric motors, carrying coal from the loading point to the discharge point along a fixed route. The transportation process is continuous, stable, minimally interrupted, and highly automated.

Conveyor systems are used to transport coal directly from mines, industrial yards, and storage facilities to ports or transshipment depots, reducing the need for trucks, increasing productivity, and lowering dust emissions and operating costs. Many large-scale conveyor projects (with lengths of several kilometers and capacities of millions of tons per year) have been implemented in coal mining areas such as Quang Ninh, Cao Ngan, and Thai Nguyen. For example, the C6 conveyor system at Cao Ngan Thermal Power Plant is approximately 5 km long, with a designed capacity of 180 tons per hour.

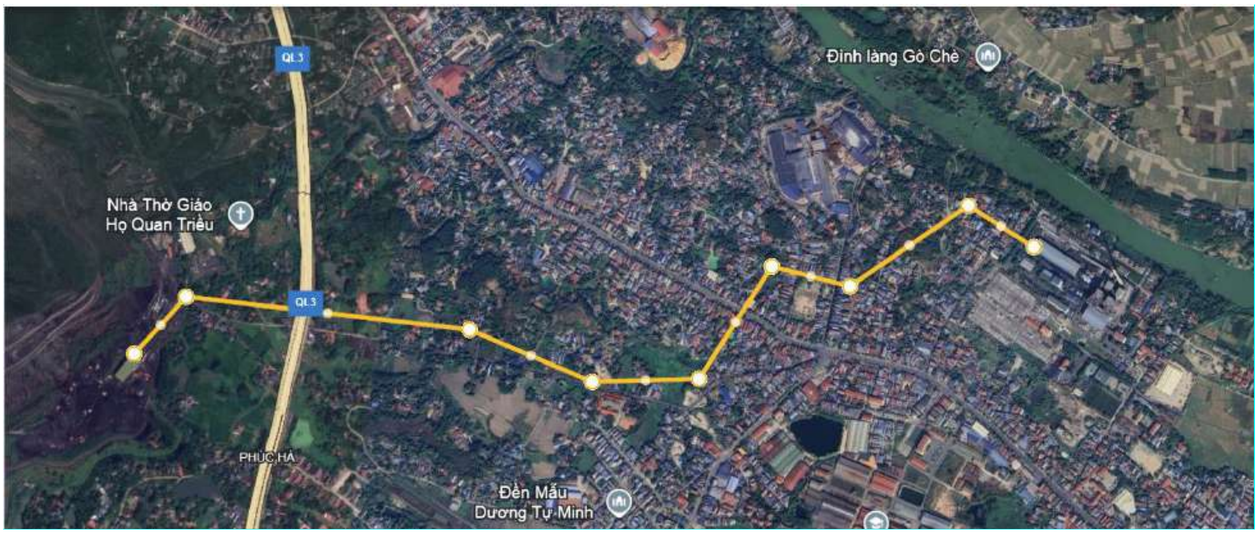

Figure 31: Conveyor system at Cao Ngan Thermal Power Plant

Main components

A coal conveyor transportation system consists of the conveyor route and supporting structures, drive and tensioning systems, coal feeding and discharge equipment, enclosure and dust control systems, control and safety systems, as well as auxiliary facilities for operation and maintenance. The conveyor line is arranged continuously from the coal receiving point to the storage yard or boiler coal feeding system, ensuring transport capacity in line with the plant's load demand. The drive and control systems are designed in an integrated manner to ensure stable and safe operation while minimizing incidents. The application of conveyor systems helps reduce long-term operating costs and provides better environmental impact control compared to other transportation methods.

Input

The input to the system is coal from the storage yard or upstream conveyor line, which is fed through a loading hopper at a flow rate and with coal characteristics suitable to the plant's operational requirements.

Output

The output of the system is coal discharged into bunkers or storage silos, with a stable flow rate that meets the operational requirements of the boiler.

Energy balance

In addition to the electricity consumed for the drive system, coal supply systems using conveyors also incur indirect losses such as spillage, dust generation, fragmentation, and increased moisture content during transportation. These losses reduce a portion of the coal's useful chemical energy and should be considered in the overall energy balance assessment of the coal handling system.

Efficiency and losses

The coal supply system using conveyors operates with high efficiency, with negligible loss of the coal's chemical energy. The primary losses are associated with electricity consumption for the drive system, along with minor indirect losses due to spillage, dust generation, fragmentation, and increased moisture during transportation.

Advantages/disadvantages

Advantages:

- Continuous and stable transportation, well suited to meeting boiler coal supply requirements under variable load conditions.
- Low electricity consumption and high transport efficiency compared to other mechanized transport methods.
- Capable of handling large volumes, suitable for medium- and large-scale thermal power plants.
- High level of automation, easily integrated with the plant's control and interlocking systems.
- Low operating and labor costs, with high reliability when properly maintained.
- Minimal impact on the coal's chemical energy, supporting the overall energy balance of the plant.

Disadvantages:

- Dependent on a fixed route, with limited flexibility when changing layout or expanding capacity.
- Potential for spillage and dust generation at loading and transfer points if enclosure design is inadequate.
- Sensitive to environmental conditions, particularly rain and high humidity, which can increase coal moisture content.
- Localized faults (belt misalignment, belt tearing, roller jamming) may affect the entire conveyor line.
- Relatively high initial investment cost for long conveyor routes with multiple transfer points.

Space requirement

In cases where a coal conveyor route passes through or is adjacent to residential areas, land use requirements and spatial constraints increase significantly due to the need to comply with additional safety, environmental, and social requirements. Therefore, route options that avoid residential areas or minimize the length of the conveyor passing through such areas should be prioritized.

Environmental

The environmental impacts of coal conveyor supply systems mainly include dust, noise, coal spillage, and visual impacts. These effects are generally localized and can be effectively controlled through appropriate design and operational measures.

Research and development

The research and development perspective for coal conveyor supply systems is oriented toward modern, highly automated, energy-efficient, and environmentally friendly transportation solutions that meet the long-term operational and sustainable development requirements of the project.

Examples of current projects

Coal conveyor supply systems have been widely applied at many coal-fired thermal power plants in Vietnam, with various route configurations from mines and coal ports to storage yards and power plants, demonstrating their feasibility, reliability, and ability to control environmental impacts.

Some conveyor routes at thermal power plants in Vietnam include:

- Na Duong Thermal Power Plant: From Na Duong coal mine → coal yard → boiler

- Cao Ngan Thermal Power Plant: From Khanh Hoa and Nui Hong coal mines → coal yard → boiler

- Mao Khe Thermal Power Plant: From Mao Khe Coal Company’s mine → coal yard → boiler

Figure 32: The coal conveyor supply system for Mao Khe Thermal Power Plant.

- Duyen Hai Power Center: From imported coal port → coal yard → boiler

- Coal transport route from Trang Bach Mine (Uong Bi Coal Company) to the +56 ground level area of Mao Khe

Figure 33: Trang Bach – Mao Khe coal conveyor route.

Prediction of performance and costs

Short term: Initial investment costs tend to increase due to stricter requirements for enclosed conveyor systems, dust suppression, and noise control, particularly for routes passing through residential areas.

Medium term: Additional investment costs gradually decrease as a result of standardized designs, localization of equipment, and accumulated operational experience.

Long term: Costs may arise for retrofitting and upgrading to comply with new environmental regulations and to extend the system's service life.

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Data sheet

Transport of coal (domestic) by conveyor										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2030)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**	**-**	**-**
Economic data										
Transfer station handling cost	USD/ton	0.13	0.13	0.11	0.12	0.13	0.04	0.13	A, B, C, D, E, F, G, H, I, J, K	1
Conveying cost	USD/ton-km	4.30	4.19	3.79	4.09	4.30	1.22	4.19	A, B, C, D, E, F, G, H, I, J, K	1

Notes:

A	Conveyor operating cost is sensitive to electricity tariffs.
B	Belt, roller and mechanical wear determine maintenance frequency and cost.
C	Transfer-station handling costs depend on site layout and throughput.
D	Labour requirements for inspection, lubrication and monitoring vary with system size and utilisation.
E	Terrain profile, elevation change and conveying distance impact efficiency.
F	Long-term projections must consider electricity-tariff variability and materials cost.
G	Improved materials, automation and monitoring systems may gradually reduce O&M cost.
H	Industrial safety and compliance requirements may introduce additional operational expenses.
I	Cost parameters are based on domestic datasets for conveyor-based coal-handling systems used at mines, industrial yards and power-plant receiving stations.
J	Electricity cost assumptions follow MOIT tariff decisions, which directly affect conveyor operating cost.
K	Scenario factors reflect equipment durability, automation levels and O&M practices of conveyor systems in Viet Nam.

References

1 Ministry of Industry and Trade of Vietnam (2025). Decision No. 1279/QD-BCT dated May 9, 2025, on the promulgation of the average retail electricity price.

3.2. Transportation of coal fuel by ship

Brief technology description

In waterborne transportation, coal is carried as bulk cargo in the ship's holds. The transport process includes the following stages: receiving coal at the export port, loading coal onto vessels using specialized equipment, transporting it via sea routes or inland waterways, and unloading at the receiving port for transfer to storage yards or the plant's coal supply system.

Transportation by sea and inland waterways (coastal routes)

Maritime transport plays an important role in supplying coal from Quang Ninh to thermal power plants in the Central and Southern regions. Coastal bulk carriers typically have capacities ranging from 1,000 to 10,000 DWT, with some vessels reaching up to 30,000 DWT (such as those transporting coal for Duyen Hai 1 Thermal Power Plant). Among them, the 5,000–7,000 DWT vessels form the core fleet. This group is capable of transporting approximately 4,000–7,000 tons of coal per voyage, suitable for long routes such as from Quang Ninh to Vung Ang, Nghi Son, and Vinh Tan.

Barge transport is the most common domestic mode, particularly along the Red River, Da Bac River, and the Quang Ninh – Hai Phong – Ninh Binh corridor. Barges used vary in capacity from 300 tons to 5,000 tons, mainly operating on Class II–III waterways in accordance with QCVN 26:2016/BGTVT, and directly connecting to port warehouses near the power plants.

Figure 34: Transportation by sea and inland waterways (coastal routes)

Transportation by sea

Imported coal is primarily transported by large bulk carriers, including Panamax (72,000 tons), Capesize (120,000–200,000 tons), and Post-Panamax (100,000 tons) vessels. After arriving at Vietnamese ports (typically dedicated terminals, coal ports, or transshipment ports), the coal is unloaded, stored, and distributed to thermal power plants, cement plants, and industrial zones.

This is considered the main method for importing large volumes of coal due to significantly lower logistics costs per ton compared to cross-border road transport.

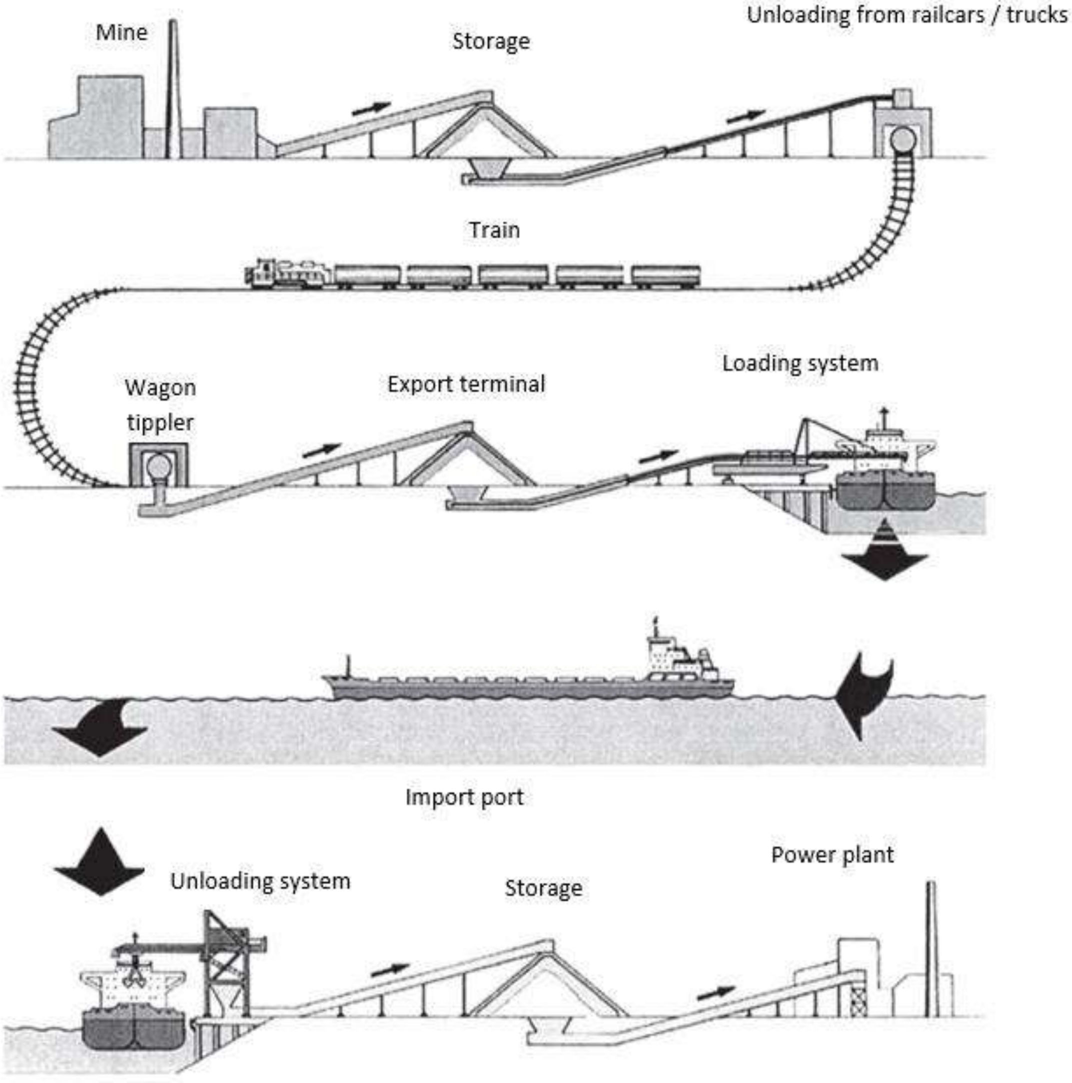

Figure 35: Typical maritime transportation.

Main components

The coal transportation system by waterway utilizes vessels or barges suitable for channel conditions and transport capacity requirements. Transport infrastructure includes waterways, navigation aids, and anchorage areas to ensure traffic safety. At the receiving point, coal is unloaded through ports or coal terminals using equipment such as cranes, grabs, and conveyor systems. After unloading, the coal is transferred to storage yards before being supplied to the plant. Auxiliary systems include transport coordination, maritime safety assurance, and environmental control measures. Waterborne transport is well suited for large volumes and long distances with relatively low transport costs; however, it depends on waterway conditions and weather.

Input

The coal transportation system by waterway receives coal from domestic mines or imported sources, meeting the plant's design requirements in terms of quality and quantity. Coal is loaded onto vessels or barges suitable for the channel conditions and the capacity of the loading port. Transport operations depend on waterway infrastructure, hydrological conditions, and vessel operating capacity. The volume of coal transported is determined in accordance with the plant's operating regime and fuel demand.

Output

The coal transportation system by waterway delivers coal to the plant's receiving port or terminal in quantities and on a schedule that meet operational requirements. After unloading, the coal is transferred to storage yards, stockpiles, or transfer systems for supply to the plant. Coal quality at the receiving point is maintained in accordance with the boiler's design and operational requirements. The receiving process ensures maritime safety, minimizes spillage, and controls environmental impacts. The system's output is coal ready for storage, feeding, and power generation processes at the plant.

Energy balance

The energy balance indicates that coal transportation by waterway is highly energy-efficient, with losses mainly associated with fuel consumption for transport vessels and energy used for loading and unloading, while the coal's chemical energy is largely preserved.

Efficiency and losses

The coal transportation system by waterway demonstrates high efficiency, as it effectively preserves both the mass and chemical energy of coal during transport. The main losses are related to energy consumption by transport vessels and loading/unloading equipment, while direct coal losses are minimal. Some losses may occur due to spillage, dust generation, and increased moisture content during transportation and handling. Overall, waterborne transport offers high energy efficiency and low losses, making it particularly suitable for large volumes and long-distance transportation.

Advantages/disadvantages

Advantages:

- Low transportation cost and high energy efficiency for large volumes and long distances.
- Large transport capacity, ensuring stable coal supply to thermal power plants.
- Lower environmental impact and less traffic pressure compared to road transport.

Disadvantages:

- Dependent on waterway conditions, hydrology, and weather.
- Requires investment in port/terminal infrastructure and specialized loading and unloading equipment.
- Lower operational flexibility in certain situations.

Space requirement

The option of transporting coal by waterway requires the use of water surface areas and riverside land for the construction of coal ports/terminals, turning basins, and anchorage areas. The location of coal storage yards and ports must be selected in areas with suitable elevation and hydrological conditions to accommodate transport vessels, while minimizing the risk of flooding due to high water levels, floods, and tidal surges. The arrangement of unloading, transshipment, and coal storage areas may alter existing land and water use conditions, particularly when transport routes pass through or are adjacent to residential areas. Therefore, it is necessary to fully consider safety corridors, ground elevation levels, environmental buffer distances, and to implement measures to minimize spatial impacts throughout the project's development and operation.

Environment

Coal transportation by waterway may generate dust, coal spillage, and noise during loading and unloading operations at ports or terminals. Vessel operations also pose potential risks of water pollution due to oil leaks and stormwater runoff carrying coal residues. The construction and operation of coal ports/terminals may alter existing land use, water surface conditions, and the surrounding landscape, particularly when located near residential areas. Therefore, appropriate management and mitigation measures should be implemented to minimize environmental impacts during both the development and operation phases of the project.

Research and development

Research and development of coal transportation systems by waterway should focus on improving operational efficiency, safety, and minimizing environmental impacts. Priority should be given to research and the gradual adoption of green-fuel transport vessels (such as LNG, biofuels, or hybrid electric–fuel systems) to reduce greenhouse gas emissions, in line with Vietnam's green transition orientation and net-zero emissions target. At the same time, greater application of automation and digital technologies should be promoted in port management, transport operations, and environmental monitoring. System development should be aligned with inland waterway infrastructure planning, energy and environmental policies, and the long-term national energy transition roadmap.

Examples of current projects

Duyen Hai Power Center: Coal is transported by sea from coal import ports in Vietnam, Australia, and Indonesia to the plant's coal port, then transferred to storage yards and the coal supply system.

Figure 36: Duyen Hai Power Center Seaport.

Vinh Tan Power Center: Coal is transported by sea from coal import ports in Vietnam, Australia, and Indonesia to the plant's coal port, then transferred to storage yards and the coal supply system.

Figure 37: Vinh Tan Power Center Seaport.

Prediction of performance and costs

The cost of coal transportation by waterway includes investment costs for port/terminal infrastructure and navigation channels, operating costs for transport vessels, and loading/unloading expenses. In the short term, initial capital investment accounts for a significant proportion of total project costs. In the medium term, unit costs tend to stabilize and decrease due to large-scale operations and optimized management. In the long term, costs may increase as a result of infrastructure upgrades and compliance with environmental standards; however, overall economic efficiency is generally improved.

References

[1] Duyen Hai Thermal Power Company Successfully Applies Coal Vessel Dispatch Management Software, Department of Innovation, Green Transition and Industrial Promotion – Ministry of Industry and Trade (VNEEC).
[2] Vinh Tan Thermal Power Company Strengthens Environmental Protection Measures, Vietnam Energy Magazine.
[3] Coal Transport: Challenges and Organization, AsstrA-Associated Traffic AG.
[4] Transportation Efficiency in Coal and Mining Supply Chains, PT. Tri Difta Utama.
[5] Australia’s Coal Exports to China in 2023 Increased 25-Fold Compared to 2022, Voice of Vietnam (VOV).
[6] Transportation by Rail and Sea in the Coal Industry, Ausenco Sandwell, Canada.

Data sheet

Transport of coal (domestic) by ship										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2030)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**		
Economic data										
Port fee	USD/ton	2.79	2.52	1.68	2.16	2.79	0.73	2.52	A, B, C, D, E, F, G, H, I, J, K	1, 2
Shipping cost	USD/ton	1.38	1.25	0.83	1.13	1.38	0.36	1.25	A, B, C, D, E, F, G, H, I, J, K	1, 2

Notes:

A	Costs are sensitive to marine fuel prices and freight-market fluctuations.
B	Port-service tariffs (pilotage, tug assistance, berthing) vary by terminal and influence total cost.
C	Vessel chartering rates depend on fleet availability and seasonal utilisation.
D	Maintenance, labour and insurance costs evolve with regulatory and market conditions.
E	Weather, navigation depth and routing constraints affect voyage efficiency.
F	Long-term projections must account for uncertainty in shipping fuel prices and port-fee adjustments.
G	Cost reductions may arise from improved scheduling, fleet optimisation and engine-efficiency upgrades.
H	Maritime environmental or safety requirements may introduce additional compliance costs.
I	USD/ton values represent aggregated maritime transport costs for representative coastal shipping routes, implicitly reflecting distance-based cost components.
J	Based on cost from Russian to Viet Nam.
K	Scenario factors reflect observed variations in port charges, vessel-fleet utilisation and coastal freight-market conditions relevant to northern Viet Nam.

References

1 Cost parameters for port fees and coastal shipping derived from domestic coal-transport datasets covering operations on the Quang Ninh–Hai Phong route

2 Supplementary information from operational data of Hai Phong thermal power plants and market sources on vessel chartering, port-service tariffs and marine fuel consumption

3.3. Transportation of coal fuel by truck/train

Brief technology description

Coal fuel transportation by land is commonly carried out in two forms: by rail or by truck. This mode of transport utilizes existing road and railway infrastructure. Coal is loaded onto trucks (dump trucks, fully or semi-enclosed trucks) or freight trains at the point of origin, then transported via the road or rail network to the receiving point. At the unloading site, coal is discharged directly into hoppers, storage yards, or conveyor systems supplying the plant. The transportation process is discontinuous in nature and depends on the number of vehicles and traffic conditions.

Rail transport of coal is still maintained on several routes in Northern Vietnam, mainly from Quang Ninh to cement and thermal power plants. The railcars used are primarily H and HR types, with a payload of 40–55 tons per car and a volume of approximately 45–60 m³ per car.

Coal delivered to the plant by road is mainly transported using box trucks or dump trucks with a payload of 10–25 tons, typically measuring 7–10.5 m in length, about 2.5 m in width, and with an overall height of 3.0–3.8 m. Accordingly, infrastructure systems such as internal roads, access gates, weighbridges, and unloading areas are designed to ensure adequate width, turning radius, and vertical clearance, meeting the requirements for safe and continuous operation. This option allows flexibility in transport organization and can accommodate increased coal demand in subsequent phases of the project.

Figure 38: Transportation coal fuel by train

Main components

The coal transportation system by truck and rail serving coal-fired thermal power plants includes transport vehicles, traffic infrastructure, loading points, unloading facilities at the plant, and management and auxiliary systems. Transport routes are organized from mines, intermediate storage yards, or coal receiving ports to the power plant, ensuring capacity and continuity in line with the operational demand of the generating units. At the plant, coal is received via unloading stations or railcar dumping facilities and then transferred to storage yards or the boiler coal feeding system. The management and auxiliary systems play a coordinating role in operations, ensuring safety and controlling environmental impacts throughout the transportation process.

Input

The input to the coal transportation system includes coal supplied from domestic mines or imported coal through ports or intermediate storage facilities, meeting the required quantity, quality, and delivery schedule for the coal-fired thermal power plant. Prior to transportation, coal is stockpiled at loading points (mines, storage yards, rail loading stations, or ports), where particle size, moisture content, and impurity composition are controlled. In addition, system inputs include the generating units' operating schedule and coal demand based on load requirements, which serve as the basis for organizing continuous and stable transportation.

Output

The output of the transportation system is coal delivered to the coal-fired thermal power plant in terms of quantity, quality, and schedule, meeting the continuous operational requirements of the generating units. After unloading, the coal is transferred to the storage yard or directly to the boiler coal feeding system, ensuring adequate stockpiling capacity and stable supply in accordance with load demand. At the same time, the transportation system provides data to support fuel management, inventory control, and the plant's production operations.

Energy balance

The energy balance of the coal transportation system is determined based on the energy consumed for transportation, loading, unloading, and transshipment in comparison with the chemical energy of the coal supplied to the plant. The primary energy inputs consist of fuel used by transport vehicles and electricity consumed by loading and receiving equipment. The useful energy corresponds to the amount of coal delivered to the plant, meeting the continuous operational requirements of the boiler. Although the energy consumed for transportation represents only a small fraction of the coal's total energy content, it has a significant impact on operating costs and emissions.

Efficiency and losses

The efficiency of the coal transportation system is evaluated based on its ability to continuously deliver coal to the coal-fired thermal power plant on schedule and in the required quality, relative to the energy and costs incurred. The system achieves high efficiency when transportation is properly organized, waiting times are minimized, vehicle payload capacity is fully utilized, and operations are synchronized with the generating units' operating schedule.

Losses during transportation include energy losses due to fuel consumption and electricity used for loading and unloading, material losses from spillage and coal shrinkage during handling and transport, as well as indirect losses caused by disruptions, congestion, or delays in coal delivery. In addition, losses are reflected in additional costs incurred and environmental emissions during operation.

Advantages/disadvantages

Advantages:

- Flexible in transport organization, especially by truck, allowing easy adjustment according to coal supply demand and plant operating conditions.
- Can utilize existing transport infrastructure (road and rail), reducing the need for new investment in certain cases.
- Suitable for short- to medium-distance coal transport and as a complementary option to waterway or conveyor transport.

Disadvantages:

- Higher operating costs compared to waterway or conveyor transport, particularly for large volumes and long distances.
- Generates dust, noise, emissions, and pressure on transport infrastructure, especially in the case of road transport.
- Stability of coal supply depends on traffic conditions, weather, and operational management capacity.

Space requirement

The coal transportation system by truck and rail requires land allocation for transport routes connecting the coal source to the coal-fired thermal power plant, including roads or railways and related auxiliary facilities. At loading and unloading points, sufficient space must be arranged for stockpiles, loading/unloading stations, receiving hoppers, and turning or passing areas for vehicles or trains. Within the plant area, adequate space is required for rail unloading yards or truck dumping stations, coal storage yards, and transfer systems feeding the boiler coal supply system. Spatial planning must take into account traffic safety corridors, environmental buffer distances, and the need to minimize impacts on nearby residential areas.

Environment

Coal transportation by truck and rail may generate dust, noise, and emissions during transport, loading, unloading, and transshipment activities. Increased vehicle traffic can place pressure on transport infrastructure and affect the environment and daily life of communities along the route. In addition, the risk of coal spillage and stormwater runoff at loading and unloading points may cause soil and water pollution if not properly controlled. Therefore, it is necessary to implement covering measures, dust control solutions, appropriate traffic organization, and environmental management practices throughout the operation process.

Research and development

Research and development of coal transportation systems by truck and rail should focus on improving operational efficiency, ensuring reliable coal supply to coal-fired thermal power plants, and minimizing environmental impacts. Priority should be given to optimizing transport organization, increasing vehicle utilization rates, and synchronizing operations with the generating units’ schedules. At the same time, there should be a gradual adoption of cleaner-fuel vehicles, energy-saving technologies, and automation in transport management. System development should be aligned with transport planning, environmental policies, and the green transition roadmap in accordance with Vietnam’s development orientation.

Examples of current projects

Transportation by truck

Na Duong Thermal Power Plant

Coal is mainly transported by truck from Na Duong mine to the plant due to the short distance and suitable infrastructure conditions.

Figure 39: Coal transportation from Laos to Vietnam by truck.

Cao Ngan Thermal Power Plant

Coal is transported by truck from mines and coal yards in the Thai Nguyen area, meeting the plant's coal supply demand.

Nong Son Thermal Power Plant

Coal is transported by truck from the mine to the plant, in line with local terrain conditions and plant scale.

Coal transport from Laos to Vietnam via the La Lay International Border Gate.

Transportation by rail

Pha Lai Thermal Power Plant

Coal is transported by rail from coal mines in Quang Ninh to the plant's coal receiving station, in combination with other transport modes.

Uong Bi Thermal Power Plant

Coal is transported by rail from nearby coal mining areas, ensuring sufficient supply and stable coal delivery.

Prediction of performance and costs

The cost of coal transportation by truck and rail includes investment costs for infrastructure and vehicles, as well as operating costs throughout the project lifecycle. In the short term, investment and operating costs are relatively high, particularly for road transport. In the medium term, unit costs may stabilize through the use of existing infrastructure and optimization of transport organization. In the long term, costs tend to increase due to infrastructure upgrades and compliance with environmental standards; however, this remains a feasible option under appropriate conditions.

References

[1] Coal Transport: Challenges and Organization, AsstrA-Associated Traffic AG.
[2] Transportation Efficiency in Coal and Mining Supply Chains, PT. Tri Difta Utama.
[3] Transporting Over 100 Thousand Tons of Coal by Rail, Thai Nguyen Newspaper.
[4] Quang Tri Proposes Construction of a 160 km "Super Conveyor" to Transport Coal from Laos to My Thuy Port, Online Journal of the Vietnam Association of Economic Sciences.
[5] Transportation by Rail and Sea in the Coal Industry, Ausenco Sandwell, Canada.

Data sheet

Transport of coal (domestic) by truck										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2030)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**	-	-
Economic data										
Yard / terminal handling fee	USD/ton	0.32	0.30	0.25	0.27	0.32	0.09	0.30	A, B, C, D, E, F, G, H, I, J, K	1
Yard / terminal fixed cost	USD	2.00	1.90	1.56	1.81	2.00	0.55	1.90	A, B, C, D, E, F, G, H, I, J, K	1
Trucking cost	USD/ton-km	0.058	0.055	0.045	0.053	0.058	0.016	0.055	A, B, C, D, E, F, G, H, I, J, K	1

Notes:

A	Trucking cost is highly sensitive to diesel prices and vehicle fuel consumption.
B	Road conditions, congestion and distance characteristics directly influence travel time and cost.
C	Handling and unloading fees vary by receiving point and operation type.
D	Labour, maintenance, tyre wear and spare-parts prices contribute to cost variability.
E	Fleet age, availability and load-factor utilisation affect cost efficiency.
F	Long-term projections must consider fuel-price uncertainty and road-regulation changes.
G	Route optimisation, fleet renewal and driver training may yield gradual cost reductions.
H	Environmental and safety compliance requirements may increase operating cost.
I	Cost parameters are derived from domestic datasets on short-distance coal trucking to industrial facilities and thermal power plants.
J	Market data include diesel prices, labour and maintenance costs, and typical handling fees at receiving sites.
K	Scenario factors reflect fleet utilisation, road conditions and standard domestic trucking practices.

References

1 PVOIL, Gasoline price list, https://www.pvoil.com.vn/tin-gia-xang-dau

Transport of coal (domestic) by train										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2030)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**		
Economic data										
Rail transport cost	USD/ton	30.00	27.12	18.10	23.21	30.00	7.87	27.12	A, B, C, D, E, F, G, H, I, J, K, L	1

Notes:

A Rail-transport cost is influenced by diesel prices and locomotive efficiency.

B Tariffs depend on wagon availability, network congestion and operator pricing policies.

C Rail terminal and yard-handling fees vary by location and service level.

D Labour, maintenance and rolling-stock refurbishment costs follow market and inflation trends.

E Track condition, gradients and routing constraints affect travel time and operating efficiency.

F Long-term projections must reflect uncertainty in fuel markets and tariff adjustments.

G Efficiency gains may come from wagon standardisation, improved scheduling and locomotive upgrades.

H Safety or signaling-system requirements can influence long-term cost structures.

I USD/ton values represent aggregated rail transport costs for representative inland routes, implicitly reflecting distance-based cost components.

J Cost assumptions are based on domestic rail-freight datasets for bulk coal movement within Viet Nam.

K Tariff structures are obtained from Vietnam Railways and relevant logistics operators.

L Scenario factors reflect locomotive efficiency, wagon availability and typical pricing mechanisms in Vietnamese rail freight.

References:

1 Vietnam Post Logistics, [Update] Latest Rail Freight Rates 2025: Detailed Price List & Standard Calculation Method for Businesses, https://vietnampostlogistics.com/gia-cuoc-duong-sat-2025

4. TRANSPORTATION OF NUCLEAR FUEL

Brief technology description

Countries around the world have safely transported radioactive materials, including fresh and used nuclear fuel, for decades. Methods for transporting nuclear fuel are undertaken in strict accordance with best practices and guidelines developed by regulatory agencies around the world and the International Atomic Energy Agency.

Nuclear energy facilities depend on the safe, efficient, and reliable transportation of all materials throughout the nuclear fuel cycle. This includes all operations, beginning with the mining of uranium, to the manufacturing of new fuel assemblies, to the eventual shipment of spent fuel to storage facilities. For security reasons, the nuclear industry accounts for all uranium from the moment it leaves the mine until its final storage.

Transportation of nuclear material varies greatly depending on the stage of the fuel cycle. Furthermore, depending on where the material is being transported by land, water or in some cases by air. Until uranium fuel is used in a reactor, the materials do not emit dangerous levels of radiation.

a) b)

Figure 40: Arrival of MOX fuel shipment from France to Japan; (b) Road transport of used fuel, Japan [1].

The transportation of milled uranium oxide, yellowcake is relatively simple. Due to the relatively low level of radiation, yellowcake is typically transported in 200L drums each holding 400kg of material. These drums are then packed into standard shipping containers.

Uranium hexafluoride due to its toxicity is transported in either Type 48Y containers for unenriched or Type 30B containers if enriched. Both these containers are large steel cylinders capable of withstanding large amounts of heat and pressure however Type 30B containers are smaller to avoid criticality risks. These containers can also be used to store depleted uranium hexafluoride at enrichment sites.

The transportation of fresh fuel depends greatly on the type of fuel and the intended reactor. Fuel is generally transported by truck or rail within countries and typically shielding for fresh fuel is not required due to the low radioactivity. Fresh fuel however does require the packaging to both prevent damage as well as prevent criticality incidents. This criticality risk also limits the number of fuel assemblies transported at once.

The transport of nuclear waste varies greatly on the level of radioactivity of the waste. Low level waste, while more radioactive than background does not require any shielding. Instead this waste is transported in standard 200L drums, usually compacted to reduce the waste volume. The transportation of intermediate level waste is a very broad form of waste but unlike low level waste requires shielding due to higher levels of radiation. The transportation of high-level waste such as used fuels is more complex as there are significant amounts of radiation as well as heat that must be managed. This material is typically placed in a Type B container which is shielded using steel and lead and for used fuel roughly 100 tons of material will be shipped per container. In case used fuel is reprocessed to recover plutonium which is transported as plutonium oxide with special measures taken to prevent criticality risks [2].

Figure 41: Unloading specialized containers from spent nuclear fuel transport railcars in Russia [3].

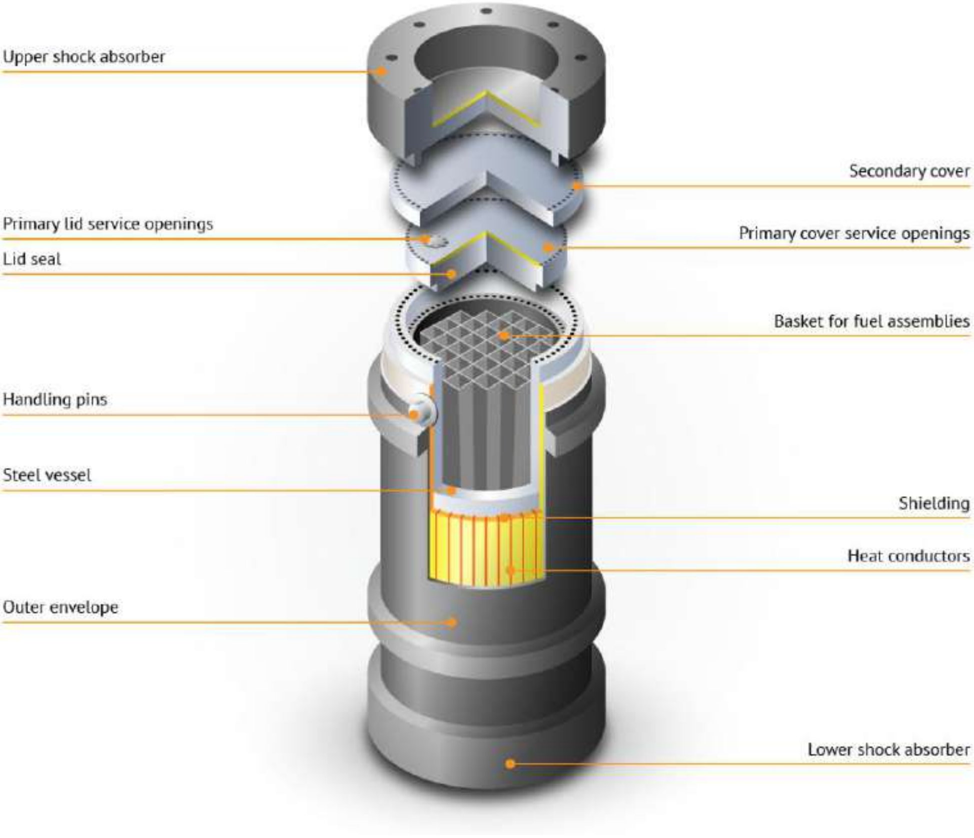

Figure 42: Cross section of a flask used for transport and storage of spent nuclear fuel – g for reactors using square fuel assemblies [4].

Many of the same principles apply to transporting nuclear isotopes for applications outside of the generation of power, such as food irradiation, crop improvements, industrial gauges and non-destructive testing, and medical diagnosis and therapy.

Fast Information:

- Each year there are about 20 million shipments of radioactive materials worldwide.
- Since 1971, more than 80,000 tons of used nuclear fuel have been safely transported over both land and sea.
- To date, there has never been an accident in which a container transporting highly radioactive material has been breached or has leaked.

Some Information about Transporting Nuclear Fuel in the UAE [5]:

- Shipping casks and containers are tested and certified by FANR and under the specification of the IAEA.
- In 2014, FANR approved the fuel transportation containers for Barakah's nuclear fuel.
- Before nuclear fuel can be transported, imported, handled and stored in the UAE, ENEC has had to obtain four separate licenses from FANR regulating these activities.
- UAE signed the Convention on the Physical Protection of Nuclear Material in 2003 and adheres to its rules.

IAEA Safety Standards and Regulations for Nuclear Fuel Transport

The transportation of nuclear fuel and related radioactive materials for nuclear power plants shall comply with the international safety standards and regulations issued by the International Atomic Energy Agency (IAEA). In particular, the document Regulations for the Safe Transport of Radioactive Material (SSR-6) establishes the fundamental safety requirements for the classification, packaging, labelling, handling, and transport of radioactive materials throughout the entire transport chain.

According to these regulations, both fresh nuclear fuel and spent nuclear fuel must be transported in specially designed transport casks that meet stringent requirements for structural integrity, impact resistance, fire resistance, water immersion resistance, and radiation shielding performance. The design and certification of transport packages shall comply with the technical requirements specified in Advisory Material for the IAEA Regulations for the Safe Transport of Radioactive Material (SSG-26) and other relevant IAEA guidance documents.

In addition, transport operations must comply with requirements related to the classification of radioactive materials, radiation dose limits, package integrity control, nuclear security measures, and emergency preparedness during transport. These requirements apply to all transport modes, including road, rail, sea, and air transport, in order to ensure a high level of protection for people, the environment, and infrastructure.

The application of IAEA safety standards ensures that nuclear fuel transportation is conducted in accordance with international best practices and meets the requirements for nuclear safety, radiation protection, and environmental protection.

References

[1] World Nuclear Association. (n.d.). *Transport of Radioactive Material*. Retrieved October 29, 2025, from https://world-nuclear.org/information-library/nuclear-fuel-cycle/transport-of-nuclear-materials/transport-of-radioactive-materials

[2] International Atomic Energy Agency (IAEA). *Transport*. Retrieved October 30, 2025, from https://www.iaea.org/emergency/nuclear-fuel-cycle/transport

[3] O.L. Tashlykov, S.E. Shcheklein, Ta Van Thuong. (2024). *Fundamentals of Nuclear Energy*. Ural University Publishing House, ISBN 978–5-7996-3867-2, Ekaterinburg.

[4] E. Encyclopedia. (n.d.). *Transportation*. Retrieved October 29, 2025, from https://www.energyencyclopedia.com/en/nuclear-energy/nuclear-fuel/transportation

[5] Emirates Nuclear Energy Company (ENEC). *Transporting Nuclear Fuel Assemblies*. Retrieved October 31, 2025, from https://www.iaea.org/emergency/nuclear-fuel-cycle/transport

APPENDIX 1: METHODOLOGY

Scope

This catalogue presents data for energy transport technologies. The main purpose of the catalogue is to provide generalized data for analysis of energy systems, including economic scenario models and high-level energy planning.

The following energy transport systems (corresponding to the energy carriers) are treated in the catalogue:

- Electricity
- Gas and liquid fuel
- Coal and solid fuel
- Nuclear (overview)

For gas and liquid fuel, the catalogue introduces transport by ship and by pipeline. For coal and solid fuels, the handbook introduces transportation methods by conveyor belt, sea vessels, and railway/trucks. Energy storage installations in the respective systems are treated in a separate catalogue on energy storage. The catalogue does not contain prices for the energy itself.

Data sources and results

A guiding principle for developing the catalogue has been to rely primarily on well-documented and public information, secondarily on invited expert advice. Where unambiguous data could not be obtained, educated guesses or projections from experts are used. This is done to ensure consistency in estimates that would otherwise vary between users of the catalogue.

Cross-cutting comparisons between technologies will reveal inconsistencies which may have several causes:

- Technologies may be established under different conditions. As an example, the cost estimates for a specific technology might be established on the basis of data from ten projects. One of these might be an R&D project, some might be demonstration projects, and the cheapest may not include grid connections, etc. Such a situation will result in inconsistent cost estimates in cases where these differences might not be clear.
- Investors may have different views on economic attractiveness and different preferences. Some decisions may not be based on mere cost-benefit analyses, as some might tender for a good architect to design their building, while others will buy the cheapest building.
- Environmental regulations vary from between countries, and the environment-related parts of the investment costs, are often not reported separately.
- Expectations for the future economic trends, penetration of certain technologies, prices on energy and raw materials vary, which may cause differences in estimates.
- Reference documents are from different years.

The ambition of the present publication has been to reduce the level of inconsistency to a minimum without compromising the fact that the real world is ambiguous. So, when different publications have presented different data, the publication which appears most in compliance with other publications has been selected as reference.

General terminology and definitions

The description of energy transport technologies follows a hierarchic terminology to cover the relevant options and variants. The following diagram summarizes the hierarchy followed in the development of the catalogue and the categorization of technologies.

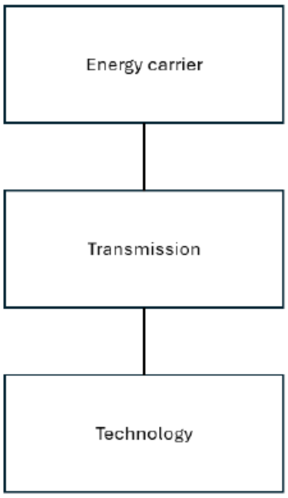

Figure 43: The hierarchy followed in the development of the catalogue and the categorization of technologies

Definitions of different components, stations and transmission systems, as well as some general assumptions follows:

Components:

Single line is defined as a transmission or distribution overhead line/cable/pipe etc. connecting two points in the network. It has a certain capacity for energy transport, an energy loss, and certain unit costs.

A substation includes elements responsible for transforming the characteristics of energy (such as voltage, pressure, etc.) at transfer points, such as transformers, step-up transformers, step-down transformers, pressure regulator, compressor; as well as elements that ensure the quality of energy supply, such as series capacitors, shunt capacitors, and FACTS devices.

Other main components of an energy carrier system can be included as well, where relevant.

Interfaces:

The interface for the transport technologies towards other parts of the energy systems are, in general upstream: The energy as delivered from the producer at the connection point. The infrastructure between the plant (power plant, gas processing plant, etc.) and the connection point, including equipment installed at the connection point is included in the plant cost and dealt with in the *Technology Catalogue for Power Generation*.

The necessary equipment for transforming and converting the energy carrier's properties on its way through the transport system, (e.g. pressure, voltage, temperature, etc.) and for powering the transport processes (pumps, compressors, etc.) are included, where relevant.

Transmission system, levels and stations:

A transmission system is defined as the network that connects the main energy producers, storage installations, etc. with the distribution networks, so that a transmission network supplies the energy to one or more distribution networks. Usually, there are no consumers connected directly to the transmission network, except for very large users or groups of users.

Substations located at points of interface to the distribution networks are included in the transmission system. Similarly, substations connecting different levels of transmission belong to the higher level.

For each of the transmission technologies a number of levels are defined corresponding to the relevant voltage, pressure, or temperature levels. Separate data sheets are provided for each transmission level. For some technologies only one level is relevant.

Table 31: Transmission level

Transmission, [technology]	**Level**		
	1	**2**	**3**
Natural Gas[27]	>60 bar	~20 bar	~2-3 bar
Electricity, overhead lines	500 kV	220 kV	
Electricity, cables	500 kV	220 kV	

For the electricity transport system in Vietnam, the grid with voltage ≥ 220 kV is transmission grid and the grid with voltage < 220 kV is distribution grid.

Furthermore, a number of different station types may be relevant for a certain technology and level:

Table 32: Substation level

Transmission	**Stations [type 1] (level change)**	**Stations [type 2] (auxiliary service)**
Natural Gas	- M/R station (pressure release) - Compressor	
Electricity, overhead lines	Transformer station / Substation	Compensation[28]
Electricity, cables	Transformer station / Substation	Compensation

General notes

The unit MW/MWh (or kW and kWh) is used in general for energy and power, though not directly convertible between the energy forms.

For natural gas, a heat value of 33.7 MJ/m^3 (for lower heating value) and 37.8 MJ/m^3 (for higher heating value) is used for conversion.

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[27] The gas pipelines in Vietnam do not yet have precise standards regarding pressure. The actual pressure depends on the design of each route and the transportation demand.

[28] In Vietnam, compensation devices and transformers are commonly installed together at the same substation.

Overview of the Technologies

The catalogue considers different technologies for transmission network. An overview of the technologies considered is shown below.

Table 33: Overview of considered technologies

Transmission technologies
• Electricity, overhead lines, AC
• Electricity, overhead lines, DC
• Electricity, underground and sea cables, AC
• Electricity, underground and sea cables, DC
• Electricity, substations, AC and DC, onshore and offshore
• Electricity, transformers
• Electricity, compensation
• H_2, 70 bar, pipeline
• H_2, 140 bar, pipeline
• NH_3, pipeline
• NG, pipeline
• LH2, L20, LHC, ship transport
• LNG, ship transport
• Coal, ship transport
• Coal, train transport
• Coal, truck transport
• Coal, conveyor transport
• Nuclear fuel transport

Each energy type (electricity, gas, coal, nuclear) is presented with a general qualitative description; however, not all sub-technologies are accompanied by dedicated data tables or detailed qualitative descriptions. Specific information for individual technologies will be provided as needed. For electricity, gas, liquid and coal energy transport, multiple quantitative data tables are included for each energy type, representing different levels and scales. For nuclear energy transport, due to the sensitive nature of the information and the limited availability of detailed data, the current content is presented only at a qualitative level, and quantitative data tables have not yet been developed. Relevant parameters will be added and updated in future editions of the Technology Catalogue once sufficient data become available.

Content

Brief technology description

Brief description for non-engineers of how the technology works and for which purpose.

For some chapters, an illustration of the technology is included, showing the main components and working principles.

Main component

Introduction to the main components and equipment of the transport system. This section lists the equipment and their primary functions within the transport chain.

Input

The main properties and sources of the energy input in the transport system, and description of the typical interface(s) at input points.

Output

The main properties of the energy at the point of connection to the consumer and the characteristic use of the energy.

Energy balance

The energy balance shows the energy inputs and outputs for the technology. This should also show the energy losses (e.g. power losses) and the input of auxiliary energy (e.g. electricity for pumping) in the transmission lines and stations.

Advantages/disadvantages

A description of specific advantages and disadvantages relative to equivalent technologies. Specific subgroups of technologies can be compared as well (e.g. HVDC vs. HVAC, overhead lines vs. cables,).

Space requirement

Space requirement is specified in 1000 m2 per MW per m. The space requirements may for example be used to calculate the rent of land, which is not included in the financial cost, since this cost item depends on the specific location of the installation.

Environment

Particular environmental characteristics are mentioned, for example visual or noise impacts, specific risks in case of leakages and the main ecological footprints.

Research and development

This section lists the most important challenges to further development of the technology. Also, the potential for technological development in terms of costs and efficiency is mentioned and quantified if possible. Vietnamese research and development perspectives are highlighted, where relevant.

Examples of current projects

Full-scale commercial projects that have been recently implemented and can be considered as standard market technologies will be presented, preferably with reference links. This section prioritizes examples of projects that have been practically deployed in Vietnam. For technologies that are new to Vietnam, representative project examples from around the world will be referenced.

Prediction of performance and costs

Cost reductions and improvements of performance can be expected for most technologies in the future. This section accounts for the assumptions underlying the cost and performance in the first technology year (base year) as well as the improvements assumed for future years.,.

The specific technology is identified and classified in one of four categories of technological maturity, indicating the commercial and technological progress, and the assumptions for the projections are described in detail.

In formulating the section, the following background information is considered:

Data for the base year

In case of technologies where market standards have been established, performance and cost data of recent installed versions of the technology in Vietnam or the most similar countries in relation to the specific technology in Asia are used for the base year estimates. In addition, the Danish Transmission Technology Catalogue is also a useful supplementary reference, providing data on technology types that are not yet available in Vietnam.

If consistent data are not available, or if no suitable market standard has yet emerged for new technologies, the base year costs may be estimated using an engineering based approach applying a decomposition of manufacturing and installation costs into raw materials, labour costs, financial costs, etc. International references such as the IEA, NREL etc. are preferred for such estimates.

Assumptions for projecting costs into future years

According to the IEA:

“Innovation theory describes technological innovation through two approaches: the technology-push model, in which new technologies evolve and push themselves into the marketplace; and the market-pull model, in which a market opportunity leads to investment in R&D and, eventually, to an innovation” [5].

The level of "market-pull" is to a high degree dependent on the global climate and energy policies. Hence, in a future with strong climate policies, demand for e.g. renewable energy technologies will be higher, whereby innovation is expected to take place faster than in a situation with less ambitious policies. This is expected to lead to both more efficient technologies, as well as cost reductions due to economy of scale effects. Therefore, for technologies where large cost reductions are expected, it is important to account for assumptions about global future demand.

The **IEA's Announced Pledges Scenario (APS)** is used as a central estimate for projections in the Technology Catalogue, whenever possible. The IEA describes the Announced Pledges Scenario in their 2022 version as follows:

"The Announced Pledges Scenario introduced in 2021 aims to show to what extent the announced ambitions and targets, including the most recent ones, are on the path to deliver emissions reductions required to achieve net zero emissions by 2050. It includes all recent major national announcements as of September 2022 for 2030 targets and longer-term net zero and other pledges, regardless of whether these have been anchored in implementing legislation or in updated NDCs. In the APS, countries fully implement their national targets to 2030 and 2050, and the outlook for exporters of fossil fuels and low emissions fuels like hydrogen is shaped by what full implementation means for global demand. […] Non-policy assumptions, including population and economic growth, are the same as in the STEPS."

According to the IEA, the less ambitious **Stated Policies Scenario (STEPS)** "provides a more conservative benchmark for the future, because it does not take it for granted that governments will reach all announced goals. Instead, it takes a more granular, sector-by-sector look at what has actually been put in place to reach these and other energy-related objectives, taking account not just of existing policies and measures but also of those that are under development. The STEPS explores where the energy system might go without a major additional steer from policy makers."

The STEPS Scenario may be used as an upper bound and to assess the expected development of technologies based on a frozen-policy approach. Previous versions of the Technology Catalogue (Technology catalogue for power generation) have used the outdated New Policies Scenario, relatively equivalent to the current STEPS, as a central framework for projections (and supplemented by other outdated scenarios of the IEA). This scenario corresponds to the frozen-policy approach that the Danish Energy Agency uses to project international fuel prices and CO_2-prices and technologies may be assessed in that regard when suitable.

Technologies updated before this cutoff date and which do not contain any explicit methodological description within the chapter regarding alternative supplementary scenarios have been updated based in this previous methodology.

As a more ambitious projection, the **Net Zero Emissions by 2050 Scenario (NZE)** may be used as a lower bound for the technology development. According to the IEA, the NZE "is a normative IEA scenario that shows a pathway for the global energy sector to achieve net zero CO2 emissions by 2050, with advanced economies reaching net zero emissions in advance of others. This scenario also meets key energy-related United Nations Sustainable Development Goals (SDGs), in particular by achieving universal energy access by 2030 and major improvements in air quality. It is consistent with limiting the global temperature rise to 1.5 °C with no or limited temperature overshoot (with a 50% probability), in line with reductions assessed in the IPCC in its Sixth Assessment Report."

By using this approach, the quantitative data in the Technology Catalogue provides a sample space that is consistent with the IEA's Global Energy and Climate Model, encompassing relevant outcomes for policy assessments of technologies as well as technology developments in compliance with national targets, and international treaties.

Learning curves and technological maturity

Predicting the future costs of technologies may be done by applying a cost decomposition strategy, as mentioned above, decomposing the costs of the technology into categories such as labour, materials, etc. for which predictions already exist. Alternatively, the development could be predicted using learning curves. Learning curves express the idea that each time a unit of a particular technology is produced, learning accumulates, which leads to cheaper production of the next unit of that technology. The learning rates also take into account benefits from economy of scale and benefits related to using automated production processes at high production volumes.

The potential for improving technologies is linked to the level of technological maturity. The technologies are categorized within one of the following four levels of technological maturity.

Category 1. Technologies that are still in the *research and development phase*. The uncertainty related to price and performance today and in the future is highly significant.

Category 2. Technologies in the *pioneer phase*. The technology has been proven to work through demonstration facilities or semi-commercial plants. Due to the limited application, the price and performance is still attached with high uncertainty, since development and customization is still needed. The technology still has a significant development potential.

Category 3. *Commercial technologies with moderate deployment*. The price and performance of the technology today is well known. These technologies are deemed to have a certain development potential and therefore there is a considerable level of uncertainty related to future price and performance.

Category 4. *Commercial technologies, with large deployment*. The price and performance of the technology today is well known and normally only incremental improvements would be expected. Therefore, the future price and performance may also be projected with a relatively high level of certainty.

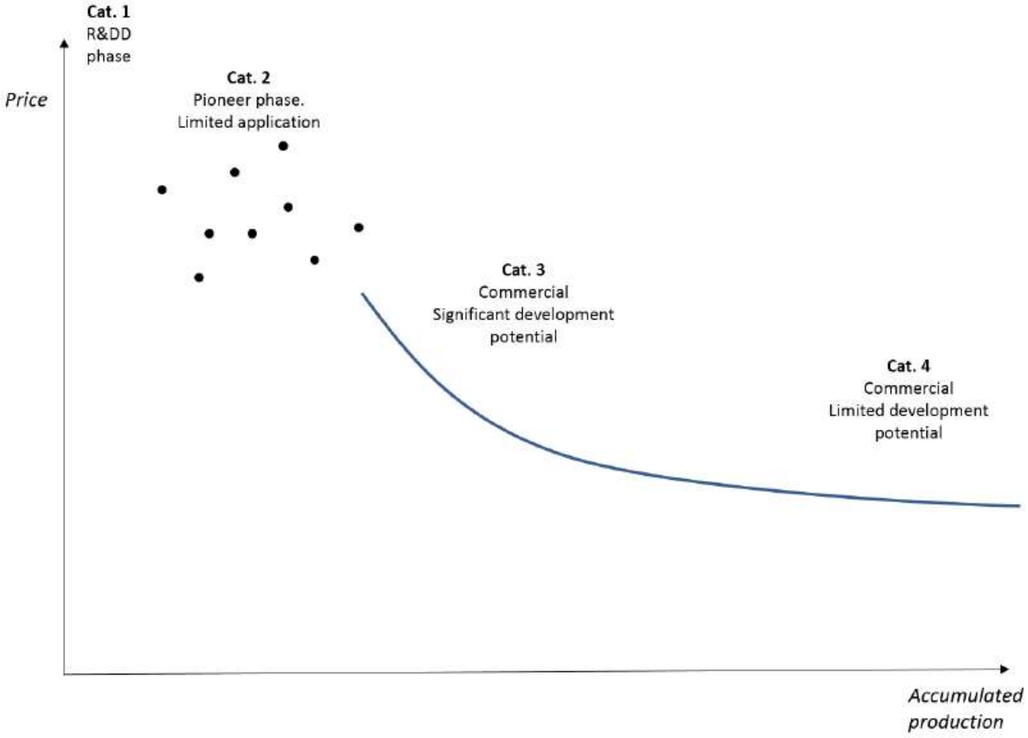

Figure 44: Technological development phases. Correlation between accumulated production volume (MW) and price

Uncertainty

The catalogue covers both mature technologies and technologies under development. This implies that the price and performance of some technologies may be estimated with a relatively high level of certainty whereas in the case of others, both cost and performance today as well as in the future are associated with high levels of uncertainty.

This section of the technology chapters explains the main challenges to precision of the data and identifies the areas on which the uncertainty ranges in the quantitative description are based. This includes technological or market related issues of the specific technology as well as the level of experience and knowledge in the sector and possible limitations on raw materials. The issues should also relate to the technological development maturity as discussed above.

The level of uncertainty is illustrated by providing a lower and higher bound beside the central estimate, which shall be interpreted as representing probabilities corresponding to a 90% confidence interval whenever possible. It should be noted, that projecting costs of technologies far into the future is a task associated with very large uncertainties. Thus, depending on the technological maturity expressed and the period considered, the confidence interval may be very large. It is the case, for example, of less developed technologies (category 1 and 2) and longtime horizons (2050).

Additional remarks

This section includes other information, for example links to web sites that describe the technology further or give key figures on it.

References

References are numbered in the text in squared brackets and bibliographical details are listed in this section.

Data sheet

To enable comparative analyses between different technologies it is imperative that data are actually comparable: All cost data are stated in real prices excluding value added taxes (VAT) and other taxes. The information given in the tables relate to the development status of the technology at the point of final investment decision (FID) in the given year (2025, 2030, 2035, 2040 and 2050 where applicable). FID is assumed to be taken when financing of a project is secured and all permits are at hand. The year of commissioning will depend on the construction time of the individual technologies after permits have been received.

A typical table of quantitative data is shown below, containing all parameters used to describe the specific technologies. The parameters are divided into two groups: technical parameters and economic parameters. For technical parameters, most technology types provide only the basic indicators, including losses, technical lifetime, construction time, etc., which are necessary for long-term planning models and do not go into detailed specifications. For economic parameters, investment costs are presented, classified according to the sub-types of technology within the larger technology group.

Uncertainties related to the figures are stated in the columns named *uncertainty*. To keep the table simple, the level of uncertainty is only specified for the base year and final year.

The level of uncertainty is illustrated by providing a lower and higher bound. These are chosen to reflect the uncertainties of the best projections by the authors. The section on uncertainty in the qualitative description for each technology indicates the main issues influencing the uncertainty related to the specific technology. For technologies in the early stages of technological development or technologies especially prone to variations of cost and performance data, the bounds expressing the confidence interval could result in large intervals. The uncertainty only applies to the market standard technology; in other words, the uncertainty interval does not represent the product range (for example a product with lower efficiency at a lower price or vice versa).

The level of uncertainty is stated for the most critical figures such as investment cost and energy losses. Other figures are considered if relevant. If a certain value in the data sheet has the value zero, this is stated as “0”. If the value is not relevant the field is left blank. All data in the tables are referenced by a number in the utmost right column (Ref), referring to source specifics below the table.

Notes include additional information on how the data are obtained, as well as assumptions and potential calculations behind the figures presented. Before using the data, please be aware that essential information may be found in the notes below the table.

A template for the datasheet for electricity transmission technologies is presented in Annex Table 1. The datasheets for fuel transport technologies follow the same general structure, but differ across technologies in terms of the parameters included, depending on their relevance and on data availability. They also report values only for the years 2025, 2030 and 2050, reflecting more limited data availability than for electricity transmission technologies. The inclusion of additional years may be considered in future updates of the catalogue.

Annex Table 1: General data sheet

Technology													
	Unit	2025	2030	2035	2040	2045	2050	2025	2025	2050	2050	Note	Ref
								lower	upper	lower	upper	-	-
Energy/technical data													
Energy losses	%/												
Technical life time	years												
Typical load factor	%												
Construction time	years												
Economic data													
Investment, type 1	USD												
Investment, type 2	USD												
Investment, type 3	USD												
Investments, installation	%												
Investments, materials	%												
Additional costs	%												
Fixed O&M	% of CAPEX/year												
Variable O&M	USD/MWh/km												
Technology-specific data													

Energy/technical data

Each transmission technology data sheet includes the technology name and the level type in the header.

Energy losses

The losses in energy transport systems are given in percent of the energy not delivered to the system, as an average over a normal (or average) year for the relevant area type (e.g. an energy loss of 50% means that half the energy fed into the system during a normal year is lost). These general values are based on experience and express typical values for representative new transmission systems. The uncertainty values indicate estimated variances from average systems, with a confidence interval of 90%.

For transmission systems, line losses are given as typical average system values in percent of the energy flow.

Energy losses in stations consist of the typical losses, if any, in various types of stations, e.g. transformer stations.

Losses are estimated entirely based on typical technical characteristics of the materials, without taking into account losses caused by other objective or subjective factors.

Technical lifetime

The technical lifetime is the expected time for which an energy line or pipe can be operated within, or acceptably close to, its original performance specifications, provided that normal operation and maintenance takes place. During this lifetime, some performance parameters may degrade gradually but still stay within acceptable limits. For instance, energy losses often increase slightly over the years, and O&M costs increase due to wear and degradation of components and systems. At the end of the technical lifetime, the frequency of unforeseen operational problems and risk of breakdowns is expected to lead to unacceptably low availability and/or high O&M costs. At this time, the line/pipe is decommissioned or undergoes a lifetime extension, which implies a major renovation of components and systems as required to make it suitable for a new period of continued operation.

The technical lifetime stated in this catalogue is a theoretical value inherent to each technology, based on experience.

In real life, specific installations of similar technology may operate for shorter or longer times. The strategy for operation and maintenance, e.g. the number of operation hours and the reinvestments made over the years, will largely influence the actual lifetime.

Typical load factor

The typical load factor expresses the utilization rate of the system.

It is expressed with a value between 0 and 1, where zero means no utilization of the system and 1 corresponds to full utilization.

In a typical transmission network, the total rated load is rarely or never reached, since the demand is diversified in time and not simultaneous.

Typical load factor is calculated as average load in a year divided by maximum load. Similarly, it could be calculated as energy transported yearly divided by maximum load and 8760 hours.

The following formula applies:

$$\text{Typical load factor}=\frac{\text{Average load [MW]}}{\text{Maximum load [MW]}}=\frac{\text{Energy transported yearly [MWh]}}{\text{8760 [h]*Maximum load [MW]}}$$

For transmission systems the load factor values vary widely, and the expected mean value is stated. The notes may indicate an expected range for lower and higher values.

Construction time

Time from final investment decision (FID) until commissioning completed (start of commercial operation), expressed in years. This data excludes objective factors such as difficulties in land clearance or external obstacles that may prevent the project from commencing operation.

Economic data

Economic data are all in USD ($), real prices, at the 2025-level and exclude value added taxes (VAT) and other taxes.

Regional data, with a particular focus on Vietnamese sources, have been emphasized in developing this catalogue. This is done as generalizations of costs of energy technologies have been found to be impossible above the regional or local levels, as per IEA reporting from 2020 [2].

Investment costs

The investment cost is also called the engineering, procurement and construction (EPC) price or the overnight cost.

The investment cost for transmission systems is reported on a normalized basis both in terms of rated power and length of transmission lines, i.e. cost per MW per m.

Where possible, the investment cost is divided on equipment cost and installation cost. Equipment cost covers the components and machinery including environmental facilities, whereas installation cost covers engineering, civil works, buildings, installation and commissioning of equipment. Cost may be disaggregated in a more detailed cost breakdown if it improves readability or understanding of the given technology, but shall also be denoted by the below categories.

The rent of land is not included but may be assessed based on the space requirements, if specified in the qualitative description.

The owners' predevelopment costs (administration, consultancy, project management, site preparation, approvals by authorities) and interest during construction are not included. The costs to dismantle decommissioned installations are also not included. Decommissioning costs may be offset by the residual value of the assets.

The investment costs for establishing new energy transport systems depend on many local and regional factors. For some installations, e.g. constructing overhead lines, experience shows that construction in areas with weak soil foundations, such as the Southwest region and the Red River Delta is more expensive compared to other regions. Furthermore, costs increase considerably in city areas where many lines may be buried next to or over each other, and traffic regulation is more complicated.

For transmission systems, the line investment costs are counted in unit length and unit power capacity costs (USD/MW/m) for different capacity ranges. Thus, the investment cost for a transmission line is found by multiplying the length and capacity with the cost for the appropriate capacity interval.

The investment cost of stations is given in unit cost per MW/MVA capacity. The type of station is stated in the data sheets. If more than one type of station is relevant for a technology, they are mentioned in separate rows in the table.

Percentage installation / materials

For the complete transmission system, it is assessed how large a share of the total investment is installation costs, and how large a share is materials. The two shares together should equal 100 percent.

Contingency

Project owners often add a contingency to a project's capital cost estimate to deal with project overruns due to uncertainties and risks caused by uncertainties in the project definition. The Association for the Advancement of Cost Engineering International (AACE International) has defined contingency as "An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience.”. AACE International further describes contingency as “…planning and estimating errors and omissions…design developments and changes within the scope, and variations in market and environmental conditions. [7] The Technology Catalogues represent general techno-economic data for different technologies; and are not intended as basis for investment decisions. Therefore, the data in the Technology Catalogues aim at not including contingency.

Operation and maintenance (O&M) costs

The fixed share of O&M includes all costs, which are independent of how many hours the components are operated, e.g. administration, operational staff, payments for O&M service agreements, property tax, and insurance. Any necessary reinvestments to keep the infrastructure operating within the technical lifetime are also included, whereas reinvestments to extend the life are excluded. The cost of reinvestments to extend the lifetime may be mentioned in a note if data are available.

The variable O&M costs include consumption of auxiliary materials (water, lubricants) and electricity, treatment and disposal of residuals, spare parts and output related repair and maintenance (however not costs covered by guarantees and insurances).

The variable O&M is in most cases very low for transmission systems and it is mainly constituted by auxiliary consumption. Where auxiliary consumption is not relevant, e.g. for electricity, this figure could equal zero.

Planned and unplanned maintenance costs may fall under fixed costs (e.g. scheduled yearly maintenance works) or variable costs (e.g. works depending on actual operating time), and are split accordingly, if relevant.

The operation costs do not include energy losses.

Auxiliary electricity consumption is included in the variable O&M for gas (natural gas, hydrogen, biogas/syngas) technologies. The electricity price applied is specified in the notes for each technology, together with the share of O&M costs due to auxiliary consumption. This enables corrections from the users with own electricity price figures. The electricity price does not include taxes and PSO.

It should be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

The fixed costs are counted per MW capacity per km transmission line at the relevant level (USD/MW/km/year), and the variable costs are counted per MWh transported per km of line USDMWh/km).

Business cycles

Historic costs of energy equipment can show fluctuations that are related to business cycles. This was the case of the period 2007-2008 for example or more recently around 2021-2022, where prices costs of many energy generation technologies increased dramatically driven by rapid increases in global raw material costs and supply chain costs. The primary objective of the technology catalogues is to establish general representative techno-economic data for different technologies, which can form a basis for energy planning activities and technical and economic analyses. The catalogues do not attempt to reflect fluctuations in technology costs due to fluctuations in costs of labour and materials driven by e.g. global/regional crises or major events affecting short term supply or demand. The technology cost developments in the catalogues thus intend to reflect an average business cycle situation and macroeconomic environment in a general long-term equilibrium.

Technology specific data

Additional data is specified in this section, depending on the technology.

This could for instance be the necessary width and depth of the trench for underground cable, the height and spacing of masts for overhead lines, the typical diameters of pipes of certain capacity ranges, transformer electrical losses depending on loads, energy losses depending on pipe classes, etc**.**

The unit and calculation method are specified in a note to the table.

References

Numerous reference documents are mentioned in each of the technology sheets. Other references used in the Guideline are mentioned below:

[1] Danish Energy Agency: "Forudsætninger for samfundsøkonomiske analyser på energiområdet" (Generic data to be used for socio-economic analyses in the energy sector), May 2009.
[2] "Projected Costs of Generating Electricity", International Energy Agency, 2020.
[3] "Konvergensprogram Danmark 2015". Social- og Indenrigsministeriet. March 2015.
[4] "Energy Technology Perspectives", International Energy Agency, 2012.
[5] International Energy Agency. Available at: http://www.iea.org/. Accessed: 11/03/2016.
[6] DEA, Technology Catalogue for Energy Transport, Denmark, 2025
[7] AACE (2022) Cost engineering terminology (https://library.aacei.org/terminology/welcome.shtml)