TECHNOLOGY DATA

Energy transport

Technology descriptions and projections for long-term energy system planning.

Danish Energy Agency

Technology Data – Energy transport

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Amendment sheet

Publication date

Publication date for this catalogue "Technology Data for Energy Transport" is December 2017. Hereby the catalogue can be updated continuously as technologies evolve, if the data changes significantly or if errors are found.

The newest version of the catalogue will always be available from the Danish Energy Agency's web site.

Amendments after publication date

All updates made after the publication date will be listed in the amendment sheet below.

Date	Ref.	Description
December 2025	Ch. 4-5	Removal of the chapters on transport of gas and liquids and replacement with more targeted chapters on transport of hydrogen by pipeline and road.
July 2025	Ch. 1	Major update and new description of the chapter, adding quantitative data for transmission level. Data for distribution level remains the same as before.
Feb 2025	Ch. 3	Updated chapter and datasheets. Datasheet for rural and LTDH removed.
April 2024	Guideline/ cover	Updated guideline in terms of scenario projection reference, price year, and further minor updates / new cover.
Nov 2021		Removal of chapters on CO2 transport including Introduction to the topic and transfer into the new Technology Catalogue for Carbon Capture, Transport and Storage.
Mar 2021	Ch. 4-5	Addition of chapters on transport of gases and liquids including introduction to the topic.
Nov 2020		Addition of chapters on CO2 transport including Introduction to the topic.

Preface

The *Danish Energy Agency* publishes catalogues containing data on technologies for energy transport. This is the first edition of the catalogue. This catalogue includes data on of a number of technologies which replace previous chapters published in the catalogue for individual heating and energy transport. The intention is that all energy transport technologies from previous catalogues will be updated and represented in this catalogue. Also the catalogue will continuously be updated as technologies evolve, if data change significantly or if errors are found. All updates will be listed in the amendment sheet on the previous page and in connection with the relevant chapters, and it will always be possible to find the most recently updated version on the Danish Energy Agency's website.

The primary objective of publishing technology catalogues is to establish a uniform, commonly accepted and up-to-date basis for energy planning activities, such as future outlooks, evaluations of security of supply and environmental impacts, climate change evaluations, as well as technical and economic analyses, e.g. on the framework conditions for the development and deployment of certain classes of technologies.

With this scope in mind, it is not the target of the technology data catalogues, to provide an exhaustive collection of specifications on all available incarnations of energy technologies. Only selected, representative, technologies are included, to enable generic comparisons of technologies with similar functions.

Finally, the catalogue is meant for international as well as Danish audiences in an attempt to support and contribute to similar initiatives aimed at forming a public and concerted knowledge base for international analyses and negotiations.

Danish preface

Energistyrelsen udarbejder teknologibeskrivelser for en række teknologier til brug for transport af energi. Dette er den første udgave af dette katalog. Dette nuværende katalog indeholder data for en stor del af teknologibeskrivelserne, som erstatter de tidligere udgivne kapitler i kataloget for individuel opvarmning go energitransport. Det er hensigten, at alle teknologibeskrivelserne fra det tidligere kataloger som omhandler energitransport, skal opdateres og integreres her. Desuden vil kataloget løbende opdateres i takt med at teknologierne udvikler sig, hvis data ændrer sig væsentligt eller hvis der findes fejl. Alle opdateringer vil registreres i rettelsesbladet først i kataloget, og det vil altid være muligt at finde den seneste opdaterede version på Energistyrelsens hjemmeside.

Hovedformålet med teknologikataloget er at sikre et ensartet, alment accepteret og aktuelt grundlag for planlægningsarbejde og vurderinger af forsyningssikkerhed, beredskab, miljø og markedsudvikling hos bl.a. de systemansvarlige selskaber, universiteterne, rådgivere og Energistyrelsen. Dette omfatter for eksempel fremskrivninger, scenarieanalyser og teknisk-økonomiske analyser.

Desuden er teknologikataloget et nyttigt redskab til at vurdere udviklingsmulighederne for energisektorens mange teknologier til brug for tilrettelæggelsen af støtteprogrammer for energiforskning og -udvikling. Tilsvarende afspejler kataloget resultaterne af den energirelaterede forskning og udvikling. Også behovet for planlægning og vurdering af klima-projekter har aktualiseret nødvendigheden af et opdateret databeredskab.

Endeligt kan teknologikataloget anvendes i såvel nordisk som internationalt perspektiv. Det kan derudover bruges som et led i en systematisk international vidensopbygning og -udveksling, ligesom kataloget kan benyttes som dansk udspil til teknologiske forudsætninger for internationale analyser og forhandlinger. Af disse grunde er kataloget udarbejdet på engelsk.

Table of contents

Guideline/Introduction

This catalogue presents data for energy transport technologies. Focus is on the existing main systems in Denmark where energy is transported in a geographically widespread network infrastructure. The following energy transport systems (corresponding to the energy carriers) are treated in the catalogue:

- Natural gas, including upgraded biogas
- District heating
- Electricity
- Hydrogen

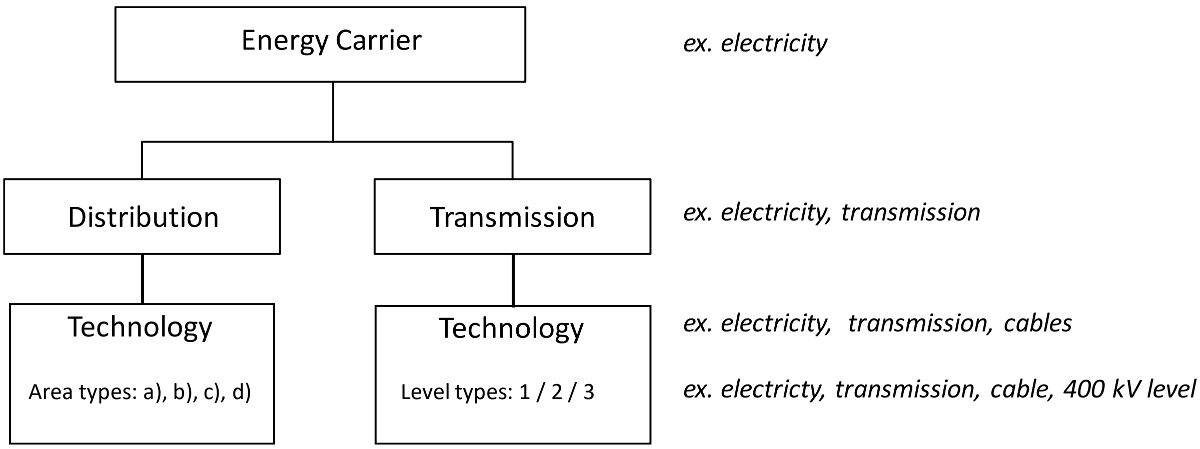
Energy storage installations in the respective systems are treated in a separate catalogue on energy storage. The catalogue does not contain prices for the energy itself.

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.

These guidelines serve as an introduction to the presentations of the different technologies in the catalogue, and as instructions for the authors of the technology chapters. The general assumptions are described in section 1.1. The following sections (1.2 and 1.3) explain the formats of the technology chapters, how data were obtained, and which assumptions they are based on. Each technology is subsequently described in a separate technology chapter, making up the main part of this catalogue. The technology chapters contain both a description of the technologies and a quantitative part including a table with the most important technology data.

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.



With a view to cross-technology comparisons, a general separation between transmission and distribution systems is maintained throughout the catalogue, as defined below. Thus, an entire energy transport system for a specific energy carrier may consist of a combination of transmission technologies and distribution ones.

Definitions of different components, stations, distribution and transmission systems, as well as some general assumptions follows:

Components:

Single line is defined as a transmission or distribution cable/pipe etc. connecting two points in the network. It has a certain capacity for energy transport, an energy loss, and certain unit costs. For district heating it comprises both the forward and return pipes.

A service line is the connection from the distribution network to each consumer's point of connection. It is assumed to be buried. It usually includes a switch/valve and a metering device at the connection point.

A distribution network is defined as a complete distribution system covering an area, including distribution lines, service lines, and necessary stations.

Two types of stations and substations are considered in this catalogue:

Station Type 1: this category includes all those stations that perform a transformation of the characteristics of the energy carrier (e.g. voltage, pressure, etc.) in correspondence to a change of level or from transmission to distribution.

Examples of these are power transformers or heat exchangers in district heating networks.

Station Type 2: this category includes those stations and equipment needed to provide a certain supply quality or to maintain the characteristics of the energy carrier.

Examples of this type are pumping stations or capacitor banks for reactive power compensation.

Other main components of an energy carrier system can be included as well, where relevant.

Interfaces:

The interfaces 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, district heating 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 Electricity and District Heating Plants*.

Downstream: The energy as delivered to the consumer. Service line and metering equipment at the point of connection are included in transport system costs.

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 (transformer stations, heat exchangers, etc.). Similarly, substations connecting different levels of transmission belong to the higher level.

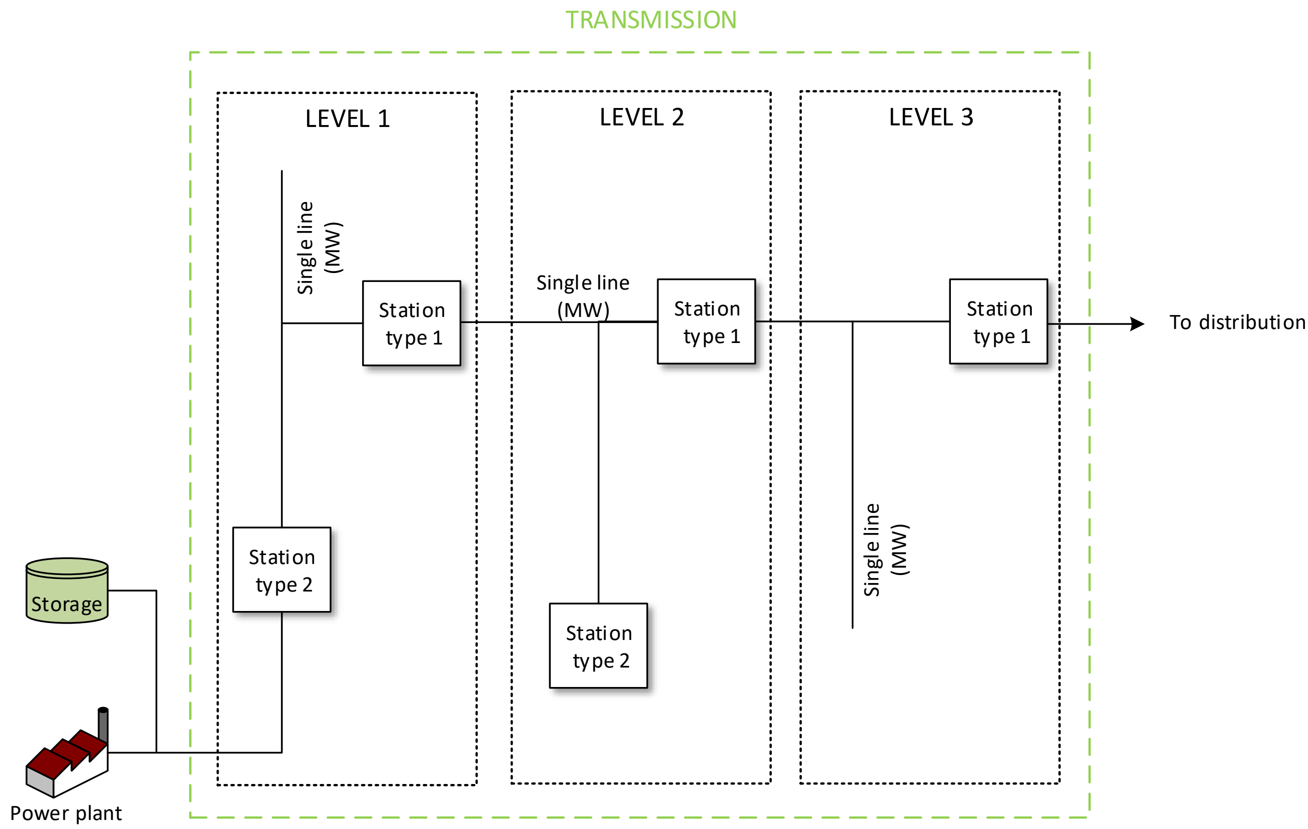
For each of the transmission technologies a number of levels are defined corresponding to the relevant voltage, pressure, or temperature levels. Separate data sheets are provided for each transmission level. For some technologies only one level is relevant.

Transmission, [technology]	Level		
	1	2	3
Natural Gas	80 bar	16 – 40 bar	
Electricity, overhead lines	400 kV	132 / 150 kV	50 / 60 kV
Electricity, cables	400 kV	132 / 150 kV	50 / 60 kV
District heating	< 110 deg. C	<80 deg. C	

Furthermore, a number of different station types may be relevant for a certain technology and 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
Electricity, cables	Transformer station / Substation	Compensation
District heating	Heat exchanger transmission/distribution	Pumping station

The following figure displays the transmission system specifying its boundaries, different levels, components and stations.



Distribution system, area types and stations:

A distribution system is defined as the network of lines that supplies energy to the consumers in a delimited area. Energy is fed into the system from either transmission networks and/or directly from one or more energy producers. The substations connecting the distribution system to the transmission system are defined to be part of the transmission systems. Other substations internally in the distribution grid are included, including pump stations, regulator stations, transformer stations, valves, etc. The service lines to consumers are also part of the distribution systems.

In this catalogue, energy distribution sub-systems are characterized by their energy consumption density, describing the yearly energy consumption per unit of area (MWh/ha or km^2). This density will highly influence the investment cost and, for some energy forms, also the operating costs and losses. In a relatively densely populated area the lengths of lines per unit consumption will be shorter, but on the other hand, the unit installation cost per unit length of distribution line is usually also higher due to more difficult burial work, traffic regulation, etc. For a simplification of this approach four different area types have been defined.

It has to be underlined that this categorization refers to commercial and/or residential areas only, while industrial areas are excluded due to the very diverse nature of consumption depending on the type of industry. Instead, the connection of a specific industry to the distribution grid can be modelled by using single components such as service lines.

The four types of areas defined are the following:

a) New developed areas
This reflects a situation where a new area is built and the installation of energy distribution systems is coordinated with the overall construction plan, which lowers the investment costs. The specific energy

consumption corresponds to requirements in present and future building codes, i.e. a relatively low energy consumption density for heat, but not necessarily for electric power since heat pumps may be a preferred heating option.

b) New distribution in existing sparsely populated rural areas, villages, etc.
In this situation a new energy distribution system is rolled out to an existing area with low energy consumption density.

c) New distribution in existing medium populated areas, suburban, etc.
In this situation a new energy distribution system is rolled out to an existing area with medium energy consumption density.

d) New distribution in existing densely populated areas, city centers, etc.
In this situation a new energy distribution system is rolled out to an existing area with high energy consumption density.

It is assumed that all relevant consumers are connected.

Separate data sheets are provided for each area type.

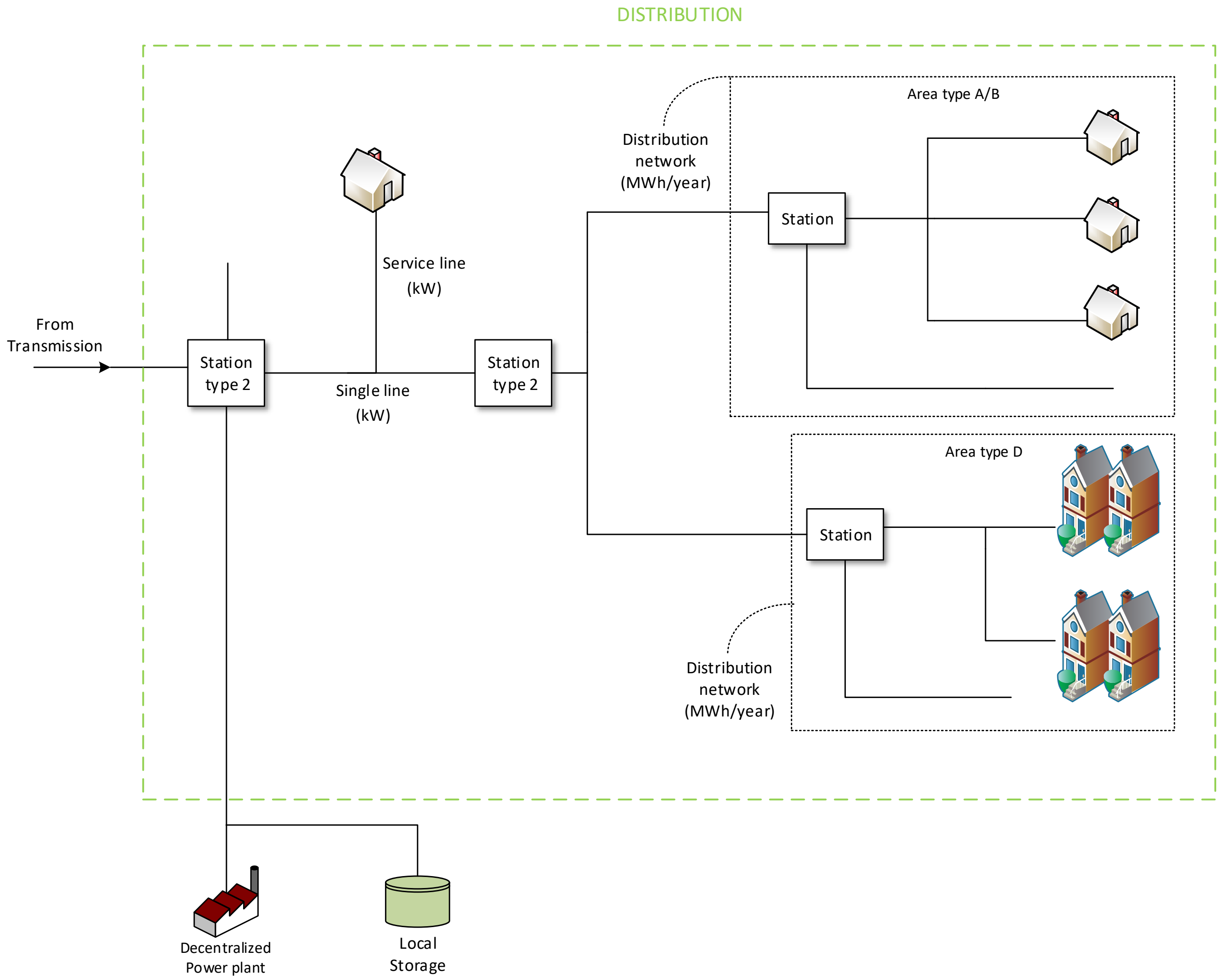
For a certain distribution technology, a number of different station types may be relevant:

Distribution	Stations [type 1] (level change)	Stations [type 2] (auxiliary service)
Natural Gas	D/R station	
Electricity, overhead lines	Transformer / substation	
Electricity, cables	Transformer / substation	
District heating	Heat exchanger station	Pump station
District heating, low temperature	Heat exchanger station	Pump station

The following figure displays the distribution system specifying its boundaries, different area types, components and stations.

As indicated, a distribution system can be composed of several distribution networks of different area types, each containing the necessary distribution lines, stations and service lines. Apart from that, the distribution system can also include individual single lines, service lines and stations outside the defined areas.

For this reason, the quantitative description includes data for both the networks defined by area type and the individual components.



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 lower calorific value of 39.6 MJ/Nm^3 or 0.011 MWh/Nm^3 is used for conversion.

Overview of the technologies

Different technologies for transmission and distribution networks are considered and each can be applied to a different transmission level (1, 2, 3) or different distribution area types (a, b, c, d).

An overview of the technologies considered is shown below.

Transmission technologies	Distribution technologies
• Natural gas, 80 bar • Natural gas, 40-16 bar • Electricity, overhead lines, 400 kV • Electricity, overhead lines, 132/150 kV • Electricity, overhead lines, 50/60 kV • Electricity, cables, 400 kV • Electricity, cables, 132/150 kV • Electricity, cables, 50/60 kV • Electricity, HVDC, 400 kV • Electricity, HVDC sea cable, 250-400 kV • Electricity, HVAC sea cable, 400 kV • Electricity, HVAC sea cable, 132/150 kV • Electricity, HVAC sea cable, 50/60 kV • District heating, < 110 deg. C / 25 bar • District heating, < 80 deg. C	• Natural gas, area type a) • Natural gas, area type b) • Natural gas, area type c) • Natural gas, area type d) • Electricity, cables, area type a) • Electricity, cables, area type b) • Electricity, cables, area type c) • Electricity, cables, area type d) • District heating, area type a) • District heating low temp., area type a)[1] • District heating, area type b) • District heating, area type c) • District heating, area type d)

Each energy carrier (electricity, gas and district heating) is represented by one qualitative description as explained in Section 1.2, but not all sub-technologies have individual datasheets or qualitative descriptions. Where relevant, specific information is given for each technology for an energy carrier. Several tables with quantitative data are included for each carrier, representing the different levels and areas. These are based on two different templates: one for transmission and one for distribution. The content of the templates is described in Section 1.3.

1.2. Qualitative description

The qualitative description covers the key characteristics of the technology as concise as possible. The following paragraphs are included where relevant for the technology.

[1] Concerning new developed areas, district heating will consist of two separate data sheets. One for conventional district heating and one for low temperature district heating

Contact information

Containing the following information:

- Contact information: Contact details in case the reader has clarifying questions to the technology chapters. This could be the Danish Energy Agency, Energinet.dk or the author of the technology chapters.
- Author: Entity/person responsible for preparing the technology chapters
- Reviewer: Entity/person responsible for reviewing the technology chapters.

Brief technology description

Brief description for non-engineers of how the technology works and for which purpose.

An illustration of the technology is included, showing the main components and working principles.

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. heat losses) and the input of auxiliary energy (e.g. electricity for pumping) in the transmission and distribution lines and stations.

Description of transmission system

A description of the transmission systems, including lines, relevant stations for conversion, and auxiliary systems is given here. This includes a description of the relevant technical equipment and various properties of the energy carriers at the different transmission levels, e.g. pressure, temperature, or voltage levels. Thus, the total transmission system may consist of sub-system networks at different transmission levels, with each their properties and characteristics. The main properties and characteristics, including dimensioning criteria and limitations for use are mentioned. The most important installation methods are described, as well as the most important operation and maintenance work.

Description of distribution system

The section contains a description of the distribution system, including a description of the relevant technical equipment and various properties of the energy carriers at the distribution level (e.g. pressure, temperature, and voltage levels), the relevant substation types, and the service line connections to the consumers. In addition, the most important installation methods are described, as well as the most important operation and maintenance work.

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.

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, high temperature vs. low temperature DH).

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 perspectives

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. Danish research and development perspectives are highlighted, where relevant.

Examples of market standard technology

Recent full-scale commercial projects, which can be considered market standard, are mentioned, preferably with links. A description of what is meant by "market standard" is given in the introduction to the quantitative description section (Section 1.3). For technologies where no market standard has yet been established, reference is made to best available technology in R&D projects.

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 Denmark or the most similar countries in relation to the specific technology in Northern Europe are used for the base year estimates.

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, labor 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*" (ref. 6).

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 before updating the guideline in april 2024 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 labor, 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 (e.g. wave energy converters, solid oxide fuel cells).

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 (e.g. gasification of biomass).

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 (e.g. offshore wind turbines)

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. (e.g. coal power, gas turbine)

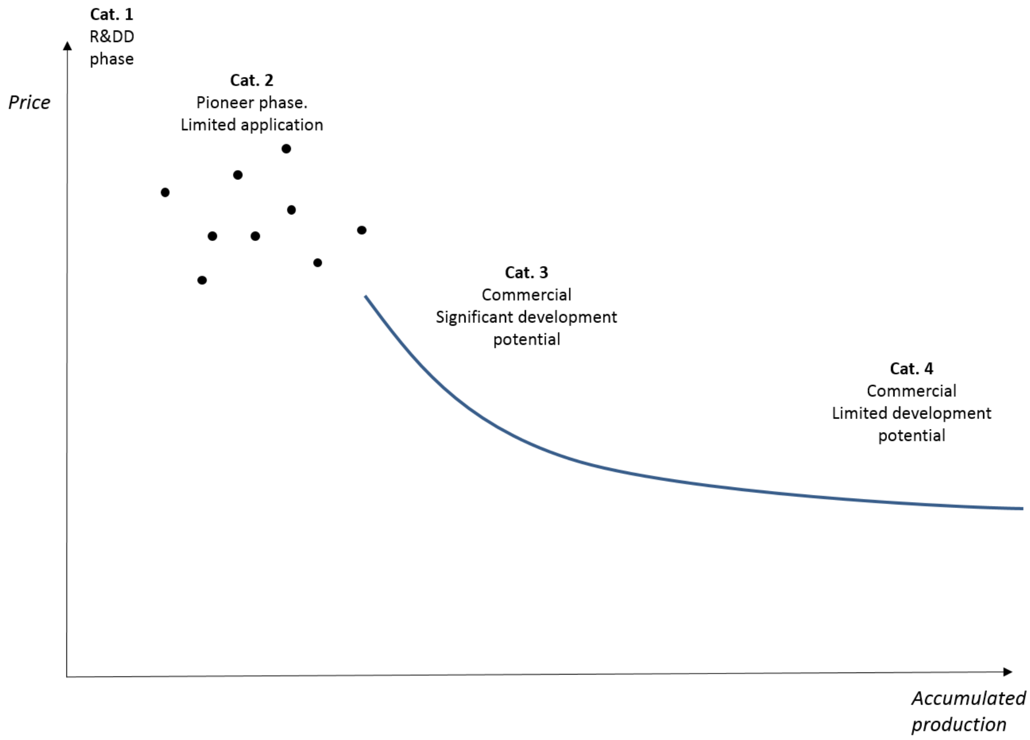


Figure 1: Technological development phases. Correlation between accumulated production volume (MW) and price.

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.

1.3. Quantitative description

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 (2015, 2020, 2025, 2030, 2023, 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 datasheet consists of a generic part, which is identical for all technologies and a technology specific part, containing information which is only relevant for the specific technology. The generic part is made to allow for easy comparison of technologies. Each cell in the table contains only one number, which is the central estimate for the market standard technology, i.e. no range indications.

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. The following separators are used:

; (semicolon)	separation between the time horizons (2015, 2020, etc.)
/ (forward slash)	separation between sources with different data
+ (plus)	agreement between sources on same data

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.

The datasheets for energy distribution technologies and energy transmission technologies are presented below:

General data sheet – Distribution technologies

[one data sheet per area type, if relevant; technology years may be updated and extended]

Technology	Energy Transport [Technology] Distribution, [area type sub-division]									
	2020[1]	2025[1]	2030[1]	2050[1]	Uncertainty (2020[1])		Uncertainty (2050[1])		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Energy losses, lines (%)										
Energy losses, stations (%)										
Auxiliary electricity consumption (% of energy delivered)										
Technical life time (years)										
Typical load factor (unitless ratio)										
- Residential										
- Commercial										
Construction time (years)										
Financial data										
Investment costs										
Distribution network costs (EUR/MWh/year) **[Area type]**									A	
Service line costs, 0 - 20 kW (Eur/unit)										
Service line costs, 20 - 50 kW (Eur/unit)										
Service line costs, 50-100 kW (Eur/unit)										

Service line costs, above 100 kW (Eur/unit)										
Single line costs, 0-50 kW (EUR/m)										
Single line costs, 50-250 kW (EUR/m)										
Single line costs, 100-250 kW (EUR/m)										
Single line costs, 250 kW - 1 MW (EUR/m)										
Single line costs, 1 MW - 5 MW (EUR/m)										
Single line costs, 5 MW - 25 MW (EUR/m)										
Single line costs, 25 MW - 100 MW (EUR/m)										
Reinforcement costs (Eur/MW)										
[type 1] station (EUR/MW)										
[type 2] station (EUR/MW)										
Investments, percentage installation (%)										
Investments, percentage materials (%)										
Operation and maintenance costs										
Fixed O&M (EUR/MW/year)										
Variable O&M (EUR/MWh)										
Technology specific data										

Notes

A: Distribution network costs include the necessary distribution lines, service lines and stations to supply an area.

[1]*Technology years may be updated from this shown example and extended*

General Data Sheet – Transmission technologies

[one data sheet per level type, if relevant; technology years may be updated and extended]

Technology	Energy Transport [Technology] Transmission, [level type]									
	2020[1]	2025[1]	2030[1]	2050[1]	Uncertainty (2020[1])		Uncertainty (2050[1])		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Energy losses, lines 1-20 MW (%)										
Energy losses, lines 20-100 MW (%)										
Energy losses, lines above 100 MW (%)										
Energy losses, stations [Type 1] (%)										
Energy losses, stations [Type 2] (%)										
Auxiliary electricity consumption (% energy transmitted)										
Technical life time (years)										
Typical load factor (unitless ratio)										
Construction time (years)										

Financial data										
Investment costs										
Single line costs, 0 - 50 MW (EUR/MW/m)										
Single line costs, 50-100 MW (EUR/MW/m)										
Single line costs, 100 - 250 MW (EUR/MW/m)										
Single line costs, 250-500 MW (EUR/MW/m)										
Single line costs, 500-1000 MW (EUR/MW/m)										
Single line costs, above 1000 MW (EUR/MW/m)										
Reinforcement costs (Eur/MW)										
[type 1] station (EUR/MW)										
[type 2] station (EUR/MW)										
Investments, percentage installation (%)										
Investments, percentage materials (%)										
Operation and maintenance costs										
Fixed O&M (EUR/MW/km/year)										
Variable O&M (EUR/MWh/km)										
Technology specific data										

Notes

[1]*Technology years may be updated from this shown example and extended*

Energy/technical data

Each transmission technology data sheet includes the technology name and the level type in the header.

Each distribution technology data sheet includes the technology name and the area type in the header.

Energy losses

The losses in energy transport systems are given in percent of the energy 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 distribution and transmission systems. The uncertainty values indicate estimated variances from average systems, with a confidence interval of 90%.

For distribution systems, the losses are divided into line losses and single station losses. The former represents an average for the total length of network lines including service lines. Line losses for the distribution side are given as average system values for the respective area types.

The latter, expresses the typical losses in stations, if any.

For transmission systems, line losses are given as typical average system values in percent of the energy flow for three different capacity ranges:

- Small lines, 1-20 MW
- Medium lines, 20 - 100 MW
- Large lines, above 100 MW

Energy losses in stations consist of the typical losses, if any, in various types of stations, e.g. transformer stations. They distinguish between losses in station types 1 and 2.

Furthermore, for district heating and gas systems in particular, there may be auxiliary energy consumption necessary for the operation of the system (pumps and compressors, heating of gas after decompression, etc.).

In case of transmission, the auxiliary consumption is stated as the typical energy use for transmitting each unit of energy in the system (% of energy transmitted).

In distribution systems, typical auxiliary energy consumption necessary for the operation of the system (pumps and compressors, heating of gas after decompression, etc.) is given as average values for the area (% of energy delivered).

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 or distribution 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:

$$Typical\ load\ factor = \frac{Average\ load\ [MW]}{Maximum\ load\ [MW]} = \frac{Energy\ transported\ yearly\ [MWh]}{8760\ [h] * Maximum\ load\ [MW]}$$

For distribution systems different values are given for typical residential and commercial areas.

The data sheet for area ´type a)´ presents the load factor for an area where new building standards (BR 10 or later) apply.

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.

Financial data

Financial data are all in Euro (€), real prices, at the 2020-level and exclude value added taxes (VAT) and other taxes. For updates before 2020, prices were given at the 2015-level Several data originate in Danish references. For those data a fixed exchange rate of 7.45 DKK per € has been used.

European data, with a particular focus on Danish 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 [ref. 3]. For renewable energy technologies this effect is even stronger as the costs are widely determined by local conditions.

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 energy distribution systems can be described as:

- A total network cost for an area with a certain yearly consumption (according to area types), or
- Split into service line costs, single line costs, station costs, and possibly reinforcement costs

The investment costs for a total distribution system may thus be composed of a combination of networks of different area types, and/or a combination of single components located outside the defined areas, as considered relevant for the specific model purpose.

For transmission systems the network costs and service line costs are not relevant.

The investment costs for establishing new energy transport systems depend on many local and regional factors. For some installations, e.g. burial of cables and pipes, experience shows that the price levels are higher in the Eastern part of Denmark, especially near Copenhagen, than in the rest of the country. 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. Also, burial of lines in paved areas is usually considerably more expensive that burial in open land.

Also there may be variations of the energy densities within each area type. For instance, a newly developed area (area type a) could consist mainly of multi-apartment building, or mainly of single family houses.

For distribution systems such variations within each area type can be accounted for by correction factors stated in the notes in the bottom of the sheets. The uncertainty values are not intended to cover these variations.

Service line costs

The cost of service lines are stated per consumer connected.

The costs include connection to the main lines and termination inside or outside the building, typically with a metering device and an isolation device (valve, contactor etc.). The data do not show whether the costs are paid by the distribution company or the consumer.

The costs of service lines depend mainly on the installed capacity, the length of the lines, and the area type. In this context average (typical) lengths have been assumed, depending on the size of the customers rated power/heat/flow capacity:

a) 0-20 kW: 20 m (for example, actual values to be stated)
b) 20-100 kW: 50 m (for example, actual values to be stated)
c) Above 100 kW: 100 m (for example, actual values to be stated)

If the lengths of lines differ from these values their costs can be scaled with length.

The service line costs are usually lower in new development areas, where the buildings as well as the distribution grid is new, corresponding to area 'type a)'.

Distribution network costs

The costs to establish distribution networks depend on the installed capacity, which with a typical load profile corresponds to a yearly energy demand. Thus, the costs are counted in EUR/MWh/year. The influence of varying energy consumption densities of different areas is accounted for by selecting the values from the data sheet with the appropriate area type.

Single line costs

The single line investment costs for distribution systems are unit length costs (EUR/m) for lines within certain capacity ranges (MW). These values can supplement the general network costs, e.g. in case of connecting isolated distribution areas with distribution lines, or for connection of single (larger) consumers. Thus, the investment cost for a distribution line is found by multiplying the length with the cost for the appropriate capacity interval.

For transmission systems, the line investment costs are counted in unit length and unit power capacity costs (EUR/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.

Reinforcement costs

Reinforcement costs are the average unit cost of reinforcing a distribution or transmission network with one MW capacity at the consumer level. This may be relevant in cases where the consumers in an existing distribution system has a higher capacity demand due to altered energy use, for instance application of heat pumps for domestic heating.

Stations

The investment costs of relevant station types in distribution and transmission systems are given in unit cost per MW 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 distribution or 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**. 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.

*Source: AACE (2022) Cost engineering terminology (https://library.aacei.org/terminology/welcome.shtml).

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. Reinvestments are discounted at 4 % annual discount rate in real terms. 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 and distribution 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 district heating and 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.

For distribution systems the fixed costs are counted per MW capacity per year (€/MW/year), and the variable costs are counted per MWh delivered to the distribution network (€/MWh).

For transmission systems the fixed costs are counted per MW capacity per km transmission line at the relevant level (€/MW/km/year), and the variable costs are counted per MWh transported per km of line (€/MWh/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 burial of lines, the height and spacing of masts for overhead lines, the typical diameters of pipes of certain capacity ranges, transformer electrical losses depending on loads, heat losses depending on pipe classes, etc.

For technologies related to transmission of electricity, the cost of overload is specified.

It represents the cost in terms of degradation of the line due to overheating caused by an overload of the line and can be used for example to calculate the convenience of overloading an existing line vs. building a new one.

The unit and calculation method is specified in a note to the table.

1.4. Definitions

Definitions of the transmission and distribution systems, as well as different area types and transmission levels, are given in the Introduction.

1.5. 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.

1 Transmission of electricity

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Amendments after publication date

Date	Reference	Description
July 25		Major update and new description of the chapter, adding quantitative data for transmission level. Data for distribution level remains the same as before
December 17		Initial publication with quantitative scope limited to distribution level

Qualitative description

Brief technology description

Strong transmission and distribution grids are key prerequisites to the transition of the power system from fossil fuel based (synchronous generation) to renewable based (often non-synchronous generation).

The electrical grid is an interconnected network that delivers electricity from suppliers to consumers. It consists of generators that produce electrical power, transmission lines that transport large quantities of power over large distances within a country or between countries, and distribution networks that distribute electricity at lower power levels to end users. Electricity transport is carried out at different voltage levels.

Voltage transformation is carried out by transformers in transformer stations. Higher voltages enable transport of larger amounts of active power at low losses. In Denmark the transmission grid system is defined as lines with voltage ranges from 132 kV and up. Near customers the voltage is reduced in several steps by step-down transformers and transported by distribution lines to users, who are supplied at voltage levels down to 230 and 400V (residential consumers). The major components of an electric power system are illustrated in Figure 1 [1] (fictional system) with generators, transmission grid and distribution system. The electrical grid is a fundamental part of the infrastructure in all developed countries.

The Danish transmission grid (Figure 1A) is owned operated and developed by the Danish TSO Energinet. It consists of an alternating current (AC) network (132 kV, 150 kV, 220 kV and 400 kV) and direct current (DC) connection between East and West Denmark and alternating current and direct current connections to neighboring areas. Larger wind farms and PV installations, including e.g., the large offshore wind farms are connected to the transmission grid. Smaller wind farms and PV installations are normally connected to the distribution grid with lower voltages.

The electrical grid in Europe is interconnected across country borders and constitutes a large and complex network. The typically meshed structure of transmission systems improves their reliability/ security of supply in the case of fault on an important system component. Many systems also possess a high degree of flexibility (up- and down regulation according to fluctuating demand (load)), which is also a precondition for integrating variable renewables as wind and solar.

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 1000 MW. Thermal power plants and nuclear power plants use fuel (fossil fuel, biofuel, 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 or snow melting periods and provide balancing power on a seasonal level.

The turbine-generator sets of thermal, nuclear, concentrated solar power systems and hydropower plants have, thanks to the large rotating masses, a significant amount of inertia. In comparison wind turbines have smaller rotating masses and inertia.

The 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.

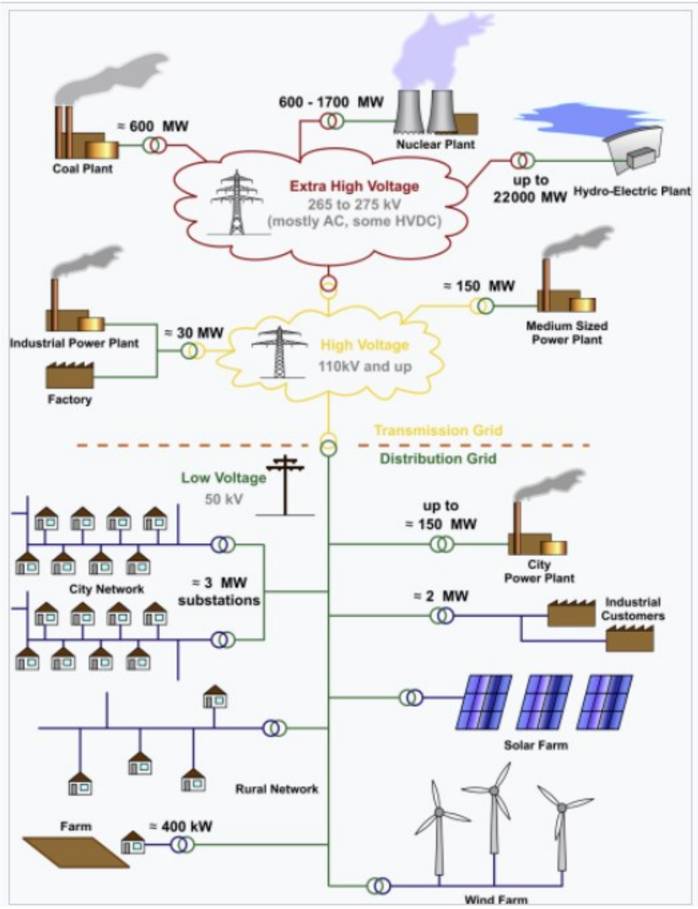


Figure 1: Illustration (example) of major components in an electric power grid, [1]

Over the last 30 years there has been an increased amount of installed capacity of non-synchronous generation (generation fuelled by the wind (kinetic energy) and solar radiation (Photo Voltaic (PV)). The development of renewables is still accelerating on a European and global basis. In 2023 wind and solar contributed with about 18% and 9 % respectively of the total European generation [2].

Denmark has for decades been a pioneer in developing commercial wind power and integrating wind in the Danish power system. In Denmark the total energy generation from wind and solar in 2023 was record high 63 % of the consumed energy with wind covering 54%, which is record high in the world. Solar (PV) contributed with 9% [3].

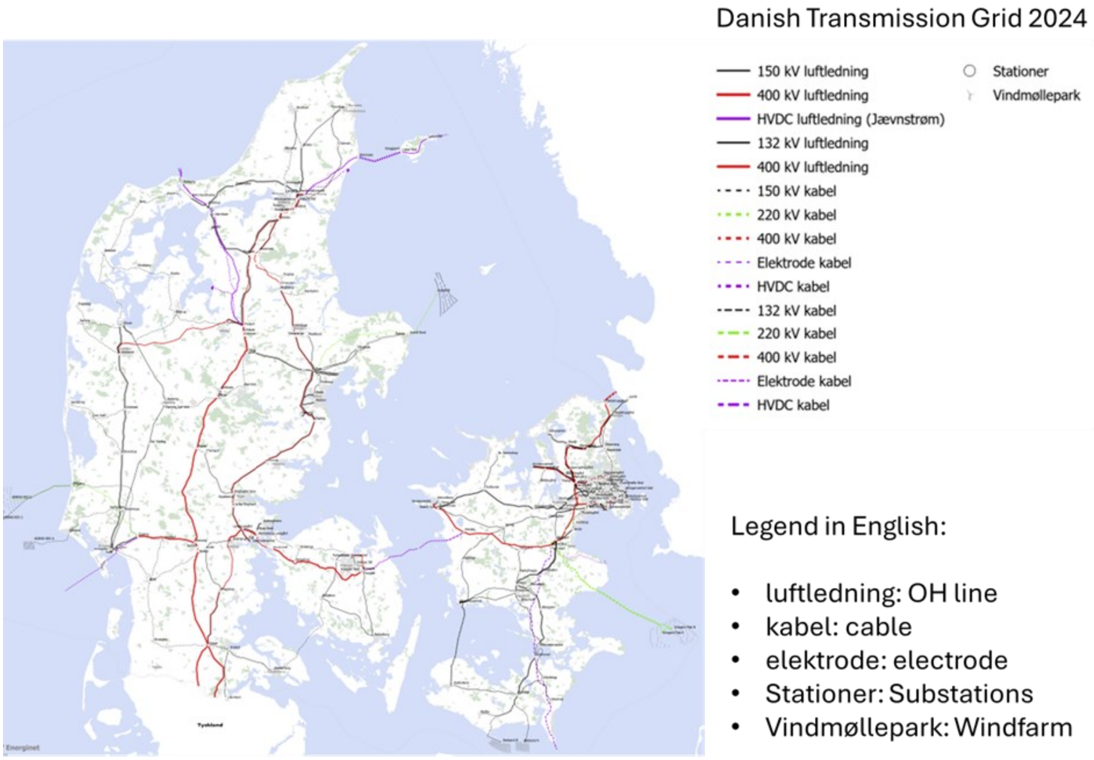


Figure 2.A: The Danish Transmission system, 2024 (Energinet)

Wind power and solar /PV power have installed capacity ranging from a few kW to installations (power plants) of several hundreds of MW, with smaller power plants connected to the distribution grid, and larger power plants connected to the transmission grid.

Today, wind and PV can participate in markets for power regulation. This mostly takes place as downregulating power, as wind and solar power normally operate at their maximum due to their low variable costs.

New wind turbine designs are most often connected to the grid through inverters. Also, PV installations are inverter connected. These sources lack the physical inertia of traditional generators, leading to potential instability and reliability issues as their presence on the grid grows. Smart inverters represent a transformative solution to the inertia challenge. These advanced systems go beyond simple energy conversion, offering capabilities to support grid stability through features like synthetic inertia, frequency and voltage control, and dynamic response to grid disturbances. Thus, the concept of “grid-forming” smart inverters has emerged as a promising solution, enabling renewable energy sources to actively participate in setting grid frequency and voltage, thus contributing to grid stability in a way that mimics traditional generators [45].

A smaller part of PV generation in Denmark comes from domestic PV, where private households and office/industrial buildings have installed PV system on the rooftop. The PV facility is connected to the low voltage system of the building, the active power may be used by the consumer and the surplus is delivered to the electrical grid. This kind of consumer is often called a prosumer.

Output

The output of the transmission system is electric power which has a vast usage in the society: the residential, commercial and industrial sector.

In the residential sector electricity is used for lighting, charging of electrical cars or bicycles, washing, refrigeration, freezing, cooking, heating (e.g. heat pump) [5].

In Denmark, private consumption for one person in an apartment is about 1900 kWh/y. For two persons the consumption in an apartment is about 2200 kWh. A family of 4 persons in a house had on average a consumption of 4,500-5,000 kWh/y in 2023 [4]. The consumption roughly doubles if a heat pump or an electrical car is included in the household consumption.

The commercial sector uses electricity for lighting, ventilation, cooling and heating, refrigerators, computers, etc. The industrial sector uses electricity to drive machinery, processes and boilers. The direct electrification of transportation sector has an increasing size, due to electrical vehicles, buses, trucks, ships/boats etc.

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 Denmark, the total grid losses are about 6-7%, where about approx. 2-3% stem from the transmission grid and approx. 4-5% stem from the distribution grid [39], [40]. The 2-3 % losses in the transmission cover DK1, DK2 and the Great Belt link excluding losses on the foreign Direct Current (DC)connections to Norway, Sweden, Holland, UK and Germany. The losses in a DC interconnection in Denmark is typically 2-3% [38].

The U.S. Energy Information Administration (EIA) estimates that annual electricity transmission and distribution (T&D) losses averaged about 5% of the electricity transmitted and distributed in the United States in 2018 through 2022 [24].

In Statistical factsheet, 2018 [46], ENTSO-E estimates the total transmission loss within ENTSO-E to be about 2 %.

The TSO takes over the balancing of the system one hour before real time. Before that a suite of electricity markets with different are active in providing a pre-balance between generation and demand, se Figure 1B:

- Forward and future financial markets, where future prices are hedged.
- Spot-markets, or day-ahead markets where generation bids and demand bids are delivered before noon (the day before real time) and the clearing of markets determines the operation of generators for the coming day. Europe has one interconnected electricity market setting the prices and

generations and exchanges in all bidding zones/countries in the same optimisation. There are similar markets in US and other parts of the world.

- Intraday markets opening when the spot market has been cleared. The market is open until one hour before real time. The market is mostly used by the market participants for self-balancing closer to real-time, when they have more certain knowledge of future conditions for generation and demand.

- When the intraday market has closed the TSOs take over the balancing in the real time market. The resources in the real-time market are different kind of reserves, that the TSO has bought in advance on the reserve markets, or they can be voluntary regulating power bids (manual reserves) given just before real time. The reserve markets include different products that the TSO needs for safely controlling the power system stability, especially in stressed situations e.g., with unplanned outages of generators, demand centres, substations and transmission and/or distribution lines.

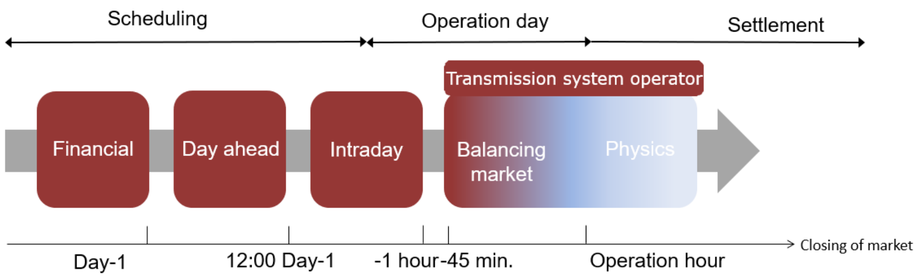


Figure 1B: Suite of power markets (Ref.: Energinet)

Description of a transmission system

General

Three phase Alternating Current (AC) systems are widely used in transmission all over the world. A transmission system is used for bulk transport of power at large distances and to interconnect large areas. The transmission system operates at high voltages, typically 110kV-1000kV, and the power capacity of lines ranges from 100 MW to several GW.

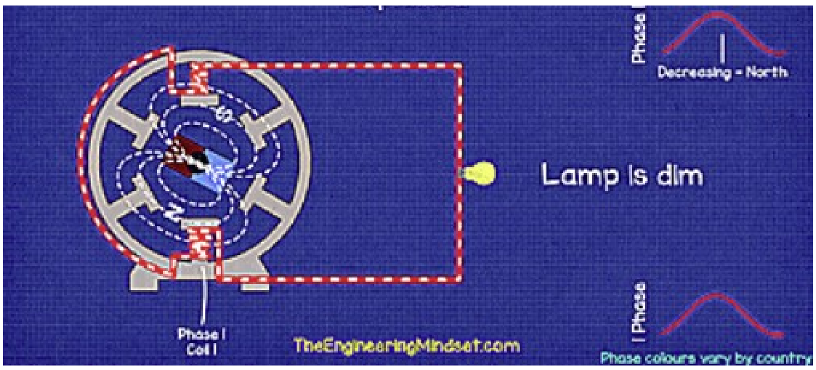


Figure 1C: AC power explained [48]

Figure 1C is an illustration of how AC electricity works. A magnet, driven by for example a wind turbine or a steam turbine, rotates and creates a varying magnetic field in the two shown coils which are connected by a conductor. The varying magnetic field induces in the line a time varying current which has the form of a sinus curve. This varying current is called a phase. When installing 4 additional coils, 2 and 2 opposite each other, two additional phases can be formed. The end result is a 3 phased AC system, with each phase described by a sinus curve and the curves being shifted 120 degrees apart.

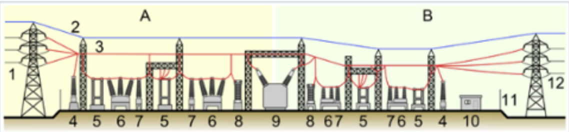
The transmission grid in Denmark operates at 132 kV to 400 kV. The transmission at 400 KV consists mainly of overhead lines. At lower transmission voltage levels underground cables are now dominating, especially in densely populated areas. Today, the transmission grid in Denmark consists of 2,900 km of overhead lines and 3,200 km of cables [12].

Substations and compensation stations

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.

Transmission substations are the 'junctions' where circuits connect to one another, creating the meshed network around which electricity flows at high voltage.

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., SF_6. AIS tends to have larger physical dimensions and requires more spacing between components, whereas GIS offers compact designs with reduced maintenance requirements. As SF_6 is a potent greenhouse gas, ENTSO-E's research programme includes efforts to develop SF_6-free solutions. 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 SF_6 for transformers in 2032.Figure 3 illustrates the layout of a substation with its elements.



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 3. Elements of a substation, example [6]

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.

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 stations

Compensation stations are 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 alternative 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.).

- Reactors absorb reactive power and reduce the voltage level on the transmission line and are typical 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/ rectors 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 [8]. The technology is based on VSCs, but a STATCOM offers better dynamic performance than an SVC, in particular a faster response time.

Interconnected large systems

High Voltage Direct Current (HVDC) connections are very often used in the transmission grid to transport large amounts of active power/ energy over long distances e.g., power transport from a major power source as an offshore wind substation. HVDC systems are also used to interconnect power systems with different frequencies or different phase angles (and same frequency).

Denmark has two separated transmission systems, of which the eastern system (DK2) is synchronous with the Nordic synchronous system and the western system (DK1) is synchronous with the grid of the Continental European synchronous area.

Large, interconnected transmission systems enable optimal power dispatch between numerous power generators with different characteristics, enhance system reliability, and are key to efficiently hosting an increasing amount of variable energy sources as wind and solar.

Reliability

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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.

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

The Danish security of supply of electrical was on average 24 outage minutes for a consumer in 2022. This corresponds to a reliability (or uptime) of 0.999954 or 99.995%. Of the 24 outage minutes 2 minutes could be related to outage in the transmission system. The remaining to the distribution system [10].

Figure 3 shows the statistics for outages in the Danish transmission system since 2007 (the unit on the y-axis is seconds). It follows that the islands of Bornholm, Læsø and Anholt contribute significantly in some years. Outage on Bornholm, Læsø and Anholt are included, as Energinet has a reserve supply obligation to the islands (only in case of interruption, which is not due to local electricity distribution network)

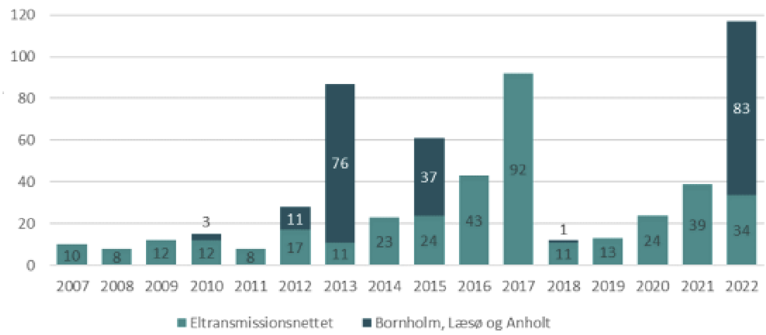


Figure 3: Outage seconds in the Danish transmission grid since 2007 (demand weighted).

The future Danish target for reliability is also high. In "Energinets redegørelse for elforsyningssikkerhed, 2023" [10], the target 10 years ahead (in 2033) for outage minutes is:

- Resource adequacy (adequacy of power): 5 minutes.
- transmission grid adequacy: 1 minute.
- robustness of transmission grid (against disturbances/faults): 1 minute.
- distribution system: 29 minutes

HVAC and HVDC systems

The majority of electric transmission systems today use three phase High Voltage Alternating Current (HVAC). Most of the electricity is produced, transferred, and consumed as AC power. Furthermore, the voltage of AC power can be stepped up and down with relative ease. Technology development has enabled the use of HVDCas 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. Such DC grids are often mentioned as overlay DC grids [11].

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. (Multi-terminals are described later in section "New technology- multi-terminals"). 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 [11].

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[3] losses that are present in AC cables.

Figure 4 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[4], lightning towers, ancillary plant etc.

Figure 4. Example of layout of HVDC, VSC substation, Greenlink[5] [50].

Above a specific break-even distance, the HVDC technology becomes cheaper than HVAC. The break-even distance for overhead lines is around 600 km and for high voltage cable lines it is around 50 km [37]. Additionally, the HVDC systems can be applied as "embedded" systems to lower the impedance[6] in specific areas of the AC network.

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

[3] 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.
[4]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.
[5] Greenlink to be commissioned in 2025
[6] Impedance is the equivalent to resistance in DC. Impedance encompasses the additional physical characteristics of an AC transmission-line/cable, which has capacitive properties and inductive properties.

run-up[7], black start capability[8] etc. The choice between HVDC and HVAC is based on economical, technical, and environmental judgments.

Voltage Source Converters (VSC) are self-commutated[9] converters to connect HVAC and HVDC systems using devices suitable for high power electronic applications, such as IGBT[10]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 [11].

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.

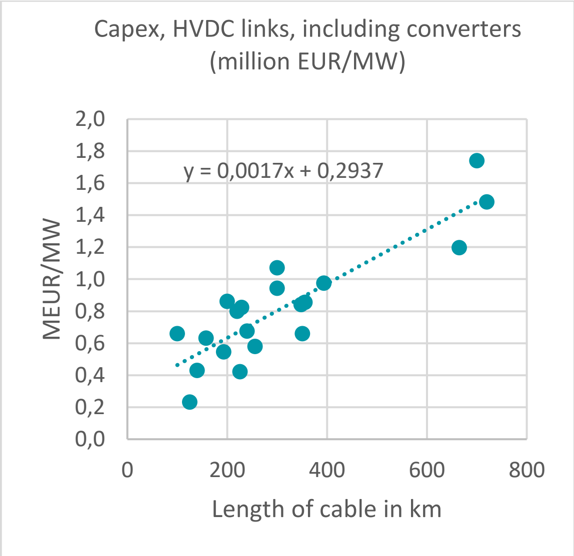
Line-commutated converters (LCCs) are the conventional, mature and well-established technology used to convert electric power from AC to DC or vice versa. The term "line-commutated" indicates that the conversion process relies on a stable line voltage at both terminals of the HVDC system [11].

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.

HVDC- point to point

In the TYNDP-22 (ENTSO-E's Ten-Year Network Development Plan) [30] 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 5. It follows that the left part of the figure has the best approximation to being linear (Coefficient of determination R^2=0,76). Figure 3 include heterogenous projects with regard to converter types (VSC/LCC) and onshore/offshore cables etc.).

[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.
[9] 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.
[10] Insulated-gate bipolar transistor



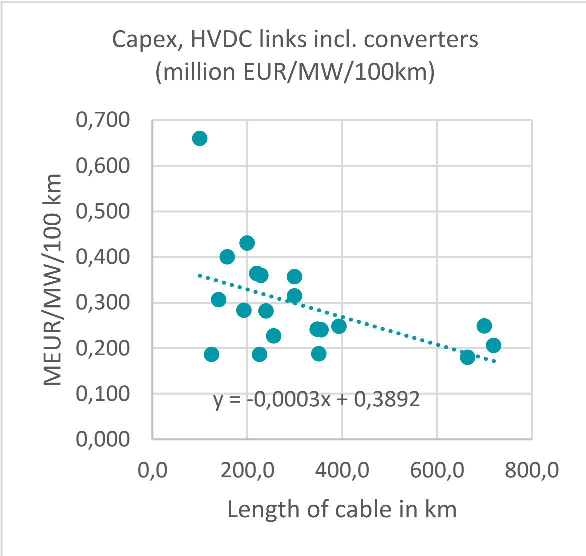


Figure 5 Capex of proposed offshore HVDC links in TYNDP 2022, including converters. In the left-hand figure capex is in MEUR/MW (R^2=0,76) and in figure to the right the capex is in MEUR/MW/100 km (R^2=0,24) (price level 2022), [30]

HVDC circuit breaker

The HVDC circuit breaker is a switching device that interrupts the flow of normal and abnormal direct current. The challenge in breaking direct current is the absence of zero current crossings. An additional component must be used that either generates zero-crossings by application of special oscillating circuit and mechanical circuit breakers or power electronics to break the current. The HVDC circuit breakers are required for meshed DC-grids and multi-terminal DC links [11].

Overhead lines vs cables

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.

The transmission grid in Denmark consists of 2,900 km of overhead lines and 3,200 km of cables: sea cables (often DC) and underground land cables (AC). The numbers include Energinet's shares of the interconnections abroad [12].

Conductors

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 [13].

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.

Superconductors [49]

Superconducting cables are based on special superconducting materials that are cooled down to extremely low temperatures (e. g., – 180 °C) using e.g., liquid nitrogen to activate the superconductivity (very low resistance). They may carry about five times the power of a conventional cable system with the same outer dimensions.

These cables are called HTS, high temperature superconductors. There exist also LTS, low temperature superconductors, where the cooling is even more extreme down to about – 268 °C, using liquid helium as coolant. For practical applications HTS seems most promising and has the focus in the following.

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.

The design of superconducting HVDC power cables is very similar to the design of superconducting HVAC power cables.

Today superconducting cables are mainly prototypes and/or form part of demonstration projects. It is uncertain when and if the cost of the technology will come down to a level making it generally and wider applicable[11].

[11] Together with "Stadtwerke München Infrastructure" and other partners, NKT in October 2024 has inaugurated the test system for the world's longest superconducting cable system, SuperLink, in the German city of Munich (https://www.nkt.dk/om-os/pressemeddelelser-events/nkt-paabegynder-test-af-verdens-laengste-superledende-kabel)

Three types of superconductors are available for AC or DC power cables:

- Bi2Sr2Ca2Cu3O10 (BSCCO) with a critical temperature of – 160 °C (liquid nitrogen as coolant)
- YBa2Cu3O7 (YBCO) with a critical temperature of – 180 °C (liquid nitrogen as coolant)
- MgB2 with a critical temperature of – 235 °C for MgB2 (liquid helium as coolant)

The critical temperature is the temperature for obtaining very low resistance.

ENTSO-E evaluates the TRL (Technology readiness level) for superconductor cables (HTS) in DC transmission to be 5-6, while TRL for superconductor cables (HTS) in AC transmission is estimated at 7-8[12].

Description of distribution system

This shorter, overall description is taken from the previous edition of the chapter that solely quantified distribution systems.

An electric power distribution system carries electricity from the transmission system to individual users. Distribution substations connect the distribution grid with the transmission grid and steps down the voltage to medium voltage, typically 10 – 70 kV. In secondary substations, distribution transformers make a final step down in voltage to low voltage (400V), distributed by service lines to end users. Users demanding larger amounts of powers can be directly connected to the medium voltage, or even higher voltage levels. Traditionally, medium voltage distribution was composed of overhead lines, which have a lower degree of technical complexity. A significant cabling of the medium voltage grid has taken place in Denmark and neighbouring countries. Drivers being increased security of supply and reduced visual pollution.

Space requirement

Space requirement for overhead lines varies in agricultural land, forest and habituated areas [43], [44]. In agricultural land the space requirement is limited to the poles and stays. In forest a 400 kV overhead line needs a clearance of 30 m – 40 m (on each side) where no trees are allowed to grow. In populated areas a clearance zone of about 40-meter width is set for non-residential buildings, whereas a clearance of approximately 200 m width is required for buildings where humans reside permanently in order to avoid exposure of magnetic fields. The space requirement reduces with lower voltages. Regarding magnetic field analysis, then this is a function of the phase-phase distances, phase distances for measurement, and the current strength (where the latter may well be independent of the voltage level).

Electric cables have a significantly lower space requirement. In populated areas and cities, cables are normally laid close to or under roads and streets. Ground cables do not affect the use of agricultural land. As far as possible, medium voltage cables follow roads also in rural areas. In forests, a clearance is required to provide easy access to the cable and to avoid tree roots from damaging the cable. For transmission grids this clearance is 10 m – 15 m. The magnetic field from cables is smaller than for overhead lines and does not add to the space requirements.

[12] TRL 5 – Laboratory testing of integrated system, TRL 6 – Prototype system verified, TRL 7 – Integrated pilot system demonstrated, TRL 8 – System incorporated in commercial design, TRL 9 – System ready for full scale deployment

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 electrical transmission infrastructure.
- 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.
- Intrusion in sensitive areas – The environmental impact due to intrusion can be minimized by e.g. avoiding placement in sensitive areas, limiting construction to winter when soil and water are more likely to be frozen and vegetation is dormant, etc.
- 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[13].

Research and development perspectives

The path towards a net zero emission system by 2050 in Europe requires new strategies and the upscaling of emerging technologies. The European TSOs are already ramping up investment programs for new infrastructure and implementing smarter system solutions, and various TSOs have set the goal of being able to operate a grid system with 100 % renewable infeed in the coming decades.

In its RDI (Research, Development and Innovation) report from 2021 ENTSO-E described the focus areas for research within the European transmission system in the years 2021-25 [15].

The ENTSO-E strategy for RDI can be illustrated by the six flagship projects shown in Figure 7. It is noticed that some of the sub-projects in the flagships are not focused directly on grid technology and grid operation but on the interplay to other areas impacting the future power grid.

[13] 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.

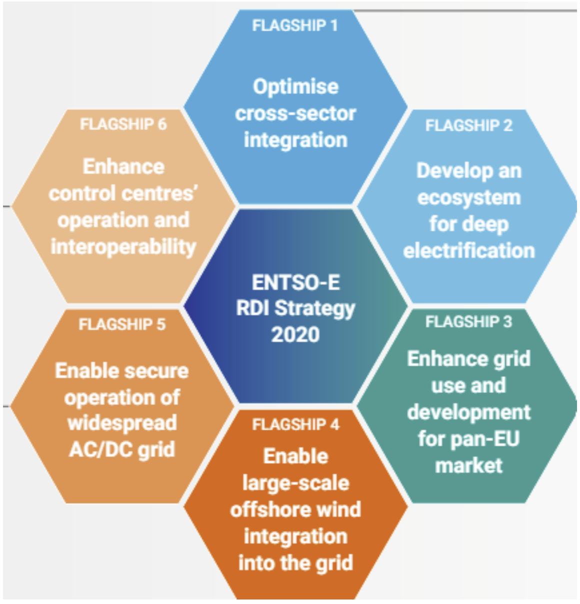


Figure 7: ENTSO-E RDI Roadmap 2020–2030 flagships and the main topics addressed in each.

Flagship 1 aims to optimize energy cross-sector integration (power, PtX, hydrogen, green fuels)

ENTSO-E proposes four project concepts in this area, covering the mass smart charging of EVs (1), the development of innovative models and tools for coordinated multi-sector operation and planning (2), the design of a pan-European cross-sector data model (3) and provision of market architecture for the cross-sector integration (4)

Flagship 2 aims to develop an ecosystem for deep electrification

Focus is on integrating the coordinated flexibility potential to the future energy system by harmonizing flexibility assessments and demonstrating how market viability and energy system security can go hand-in-hand in a coordinated approach for a P2X plant.

Flagship 3 aims to enhance grid use and development for the pan-EU market

It proposes a project concept on eco-design processes to reach SF6-free solutions, as well as a project concept to lower the carbon footprint of TSOs via lifecycle assessments embedded in smarter asset management processes.

Flagship 4 aims to enable large-scale offshore wind integration into the grid

First a project developing an interoperability framework between offshore wind and the onshore AC grid and then a follow-up project demonstrating this in practice with a full-scale multi-vendor multi-terminal high-voltage direct current (HVDC) system.

Flagship 5 aims to enable a secure operation of widespread hybrid AC/DC grids

As the share of power electronic coupled sources increases in the system and as more DC projects are embedded in the system, the main needs are concerned with the capability to properly model such systems in planning and manage them in operations.

A project on the stability management of a power electronics dominated system, and another project on assessment models for interactions, controllability and protection schemes.

Flagship 6 aims to enhance TSOs' control centres' operations and interoperability including TSOs' Energy Management Systems, a further focus on AI-driven solutions and especially on mitigating cyber risks in an efficient manner

New technology – multi-terminals

A few multi-terminal direct current (MTDC) systems are in operation around the world today. 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.

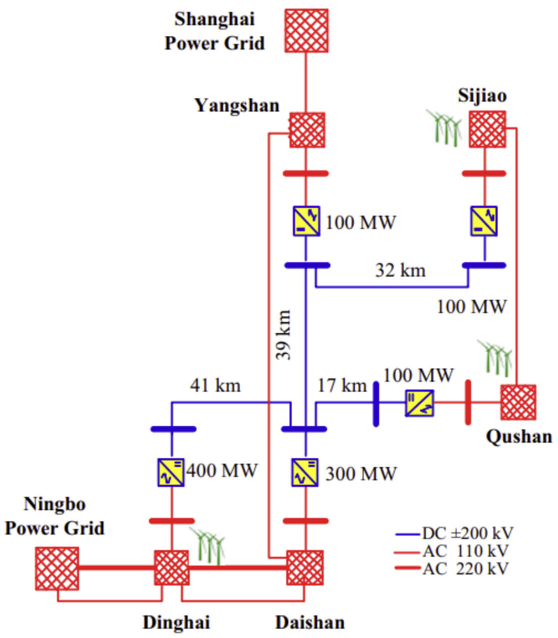


Figure 8: Zhoushan 5-Terminal DC project, China [16]

Figure 8 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[14].

Another multiterminal project is the Sardinia-Corsica-Italy radial system [17]. 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.

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, is still being examined at the research level to solve the challenges of integration with the AC meshed grid [17]. Figure is an illustration of a meshed multiterminal overlaid DC grid.

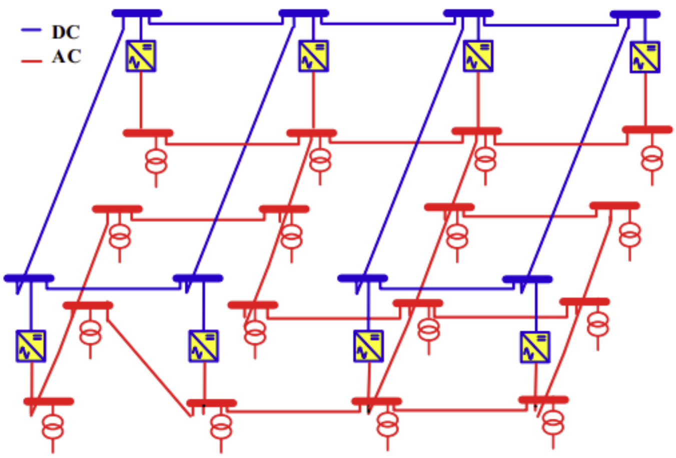


Figure 9: Example of design of a meshed multi-terminal DC [16]

Challenges and characteristics for DC grids and AC/DC hybrid grids [16], [17]

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

[14] 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.

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[15].

Protection devices and HVDC breaker

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. In this regard, several manufacturers and researchers are working on making DC circuit breakers commercially available and standardized.

Components & enablers [17]

The most important components:

- Transmission corridor technologies (LCCs[16]) with capacities of approx. 4 – 8 GW per circuit, and continuing developments towards 2050
- VSCs[17] 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

[15] 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.
[16] Line commutated converter.
[17] Voltage source converter.

Advantages & field of application [17]

The choice between an extension of a grid in AC or DC depends on a variety of technical, economic, environmental, and technical 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 will be [17]:

- An increase of transmission capacity by leveraging existing AC corridors to create new higher capacity DC corridors, boosting transmission capacity with limited additional environmental and social impact.
- An enhancement of active power flow control which enables a better utilisation of the lines closer to thermal limits.
- An increase in ancillary services provision
- Enhancement of flexibility in the overall transmission grid, being able to cope with the characteristics of renewable power infeed. To date, there exist more than 180 HVDC operational projects worldwide. A few non-meshed multi-terminal systems are in operation in Europe, North America and Asia. In the next ten years, over 25,000 km of HVDC transmission lines will be built and operated in parallel with over 300,000 km HVAC transmission lines according to the TYNDP[18] estimates, yet most of these are case-by-case, point-to-point connections.

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.

Technology Readiness Level (TRL) (ENTSO-E evaluation)[19]

[18] ENTSO-E’s Ten-year network Development Plan
[19] ENTSO-E’s Technology Readiness Levels (TRLs) are a method for estimating the maturity of technologies. The use of TRLs enables consistent, uniform discussions of technical maturity across different types of technology.

For the estimation of the TRL of DC grid systems, ENTSO-E evaluates as follows:

• TRL 9 for radial multi-terminal systems.

• TRL 4 for meshed multi-terminal systems.

Examples of market standard technology

Viking link (DC corridor between two synchronous areas)

Viking Link [18] 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

West Coast Line: New interconnector to Germany (AC corridor in the same synchronous area based on conventional AC technology)

Together with the German TSO TenneT, Energinet expands the trading capacity between Denmark and Germany by connecting the German and the Danish part of the West Coast Line [18]. On the Danish side, Energinet builds a new double circuit 400 kV overhead line from the substation Endrup to the Danish-German border.

The expansion of the interconnection capacity between Denmark and Germany is related to Viking Link – a 1400 MW interconnector between Denmark and Great Britain. With the realisation of Viking Link, it is necessary to have instant back up capacity in the Danish power system in case of failure on

Viking Link. The new line to Germany will guarantee that reserve power can be retrieved in central Europe immediately. The new power line will also increase the trading capacity between Denmark and Germany.

The new interconnector between Denmark and Germany is on the EU list of important infrastructure projects contributing to the interconnection of the European electricity networks, the so-called Projects of Common Interest (PCI).

Technical description:

- The interconnector is established as a double circuit 400 kV overhead line. In environmentally sensitive areas, the line is established with cables in the ground.
- The interconnector goes from the substation Endrup east of Esbjerg and to the German border.
- The power line is approx. 75 km long.
- The line is delayed and is expected to be commissioned in 2026.

Prediction of performance and cost

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

1. Unit Investment Cost Indicators - Project Support to ACER, PWC, final updated report, September 2023, https://www.acer.europa.eu/sites/default/files/documents/Publications/UIC_report_2023.pdf
2. 2024-ENTSOs TYNDP scenarios, downloads: https://2024.entsos-tyndp-scenarios.eu/download/
3. TYNDP 2022 project sheets (from project promoters) https://tyndp2022-project-platform.azurewebsites.net/projectsheets/transmission/
4. Screening of possible hub concepts to integrate offshore wind capacity in the North Sea, DNV for DEA, 2021, https://ens.dk/sites/ens.dk/files/Vindenergi/final_report_-_screening_of_possible_hub_concepts_to_integrate_offshore_wind_capacity_in_the_north_sea.pdf
5. Netzentwicklungsplan Strom 2035, Version 2021, German TSOs, https://mst.dk/media/xq3jv14h/netzentwicklungsplan-strom-2035-version-2021.pdf
6. Netzentwicklungsplan Strom 2035, Version 2023, German TSOs, https://www.netzentwicklungsplan.de/en/nep-aktuell/netzentwicklungsplan-20372045-2023
7. Transmission Cost Estimation Guide for MTEP22, MISO (Midcontinent Independent System Operator), 2022, https://cdn.misoenergy.org/20220208%20PSC%20Item%2005c%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP22_Draft622733.pdf
8. Ea Energy Analyses' updated data assumptions in the Balmorel model based. Original source is National Grid, FES (Future Energy Scenarios) with successive updates based on Ea's projects in the sector.
9. ENTSO-E Offshore network development plans, Jan. 2024: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/ONDP2024/ONDP2024-methodology.pdf

Source 1. The data were collected from a questionnaire. ACER (European Regulator) requested project promoters of relevant infrastructure projects to submit costs and technical data for their commissioned projects. Project promoters were asked to submit data for relevant infrastructure assets commissioned in the period 2014- 2023. This source includes assessments of OH lines (AC), underground cables (onshore), submarine cables (AC and DC), AC substations, transformers and HVDC converters.

Source 2 is from ENTSO-E. It includes planning/screening prices for use in TYNDP 2024. For electrical transmission the source only gives data for HVDC cables and onshore HVDC stations.
Source 3 is based on TYNDP2022 project sheets for concrete projects. The sheets are the results of individual assessments of project promoters.

Source 4 provides the data assumptions used in DNV's screening of hub-concepts for DEA in the North Sea. Transmission components include DC offshore cables, onshore and offshore HVDC converters and onshore HVAC transformers.

Source 5 and 6 give cost data for the German TSOs planning of transmission in the North Sea and the Baltic. Data include DC and AC cable systems and AC and DC stations.

Source 7 is a transmission cost estimation guide from MISO, US, who is the Midcontinent Independent System Operator in US. From this source we only look at data for capacitor banks, reactors and Statcoms. The reason is that the costs include all taxes and additional expenses, which we could not isolate. Also, the general price level in the US may differ from conditions in Europe.

Source 8 is Ea Energy Analyses' data assumptions in their Balmorel model. The data is routinely updated with the latest knowledge from client projects.

Source 9 is the recent data-basis for ENTSO-E's offshore development plans, 2024

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.

Quantitative description

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 2020) 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).

Price level 2020 is determined by using the yearly inflation rates in EU on average as most data has been collected from Europe.

The Inflation rates for EU on average have been [26]:

- European Union inflation rate for 2023 was 3.4%
- European Union inflation rate for 2022 was 8.83%
- European Union inflation rate for 2021 was 2.55%
- European Union inflation rate for 2020 was 0.48 %
- European Union inflation rate for 2019 was 1.63%

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.

One of the data sources, [28], has percentiles (25 and 75 percentiles) of cost figures for the specific samples in each category. These percentiles can be taken as uncertainties. In other tables the uncertainty of numbers is in general assessed as plus/minus 30 %.

Disruption of transmission asset costs

For offshore wind generation, different studies have indicated a capex increase of about 40 % during the last 3-4 years [46]. From informal talks with industry stakeholders (from TSOs and asset suppliers), it can be concluded that also capex of transmission assets has raised from 2019 to 2023, e.g. in nominal prices:

- Costs of 400 kV OHL have increased by about 20%-40%
- Costs of 400 kV substations have increased by about 40-60%
- Cost of underground cables have increased by about 65%(-100) %
- Costs of HVDC assets have increased maybe by 50-80 %

The transmission cost data published in 2023 may typically originate from project references dated 2-3 years back in time or more and have not been fully exposed to the cost disruption. Nor has earlier data. Therefore, cost data (converted to 2020 level) from reference in this catalogue has been raised accordingly to obtain 2025 cost prices (2020 price level). For all assets, prices were raised by 20% as a rough estimate to arrive at the 2025 prices. That means that part of/most of the price disruption has been reflected in e.g., 2023 prices from relevant references.

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.
- The war in Ukraine had global macroeconomic effect and also meant that important factories of transmission assets (e.g. transformers) in Ukraine were destroyed.

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 20% price rise.

Overview and discussion of collected relevant data for transmission *(For easier reading all the following tables 1-13 are also shown in the excel file of the Technology Data for Energy transport)*

Technical data for AC transmission

Table 1 presents typical and approximate values of technical parameters for transmission: energy losses and transfer capacities for the components described in this catalogue. For cables the short time load-ability (40 hours)[20] has also been indicated. The numbers are indicative and depend on specific designs of the transmission components: electrical current, line length, conductor type, impedance etc.

An illustrative comparison of capacity between Over Head Lines (OHL- and underground cables is shown in Figure 10. For combined OHL/UGC transmission lines, rated capacity of the applied cable system may be lower than rated capacity of the overhead line sections, as the short-term dynamic loadability of the cable system is designed to match the rated capacity of the OHL sections in order to meet required transmission capacity during contingencies for up to 40 hours.

[20] Insulated cables have a large thermal mass compared to overhead lines, and the thermal time constant of a cable installation and the surrounding soils normally allows for significant short-term overloading.

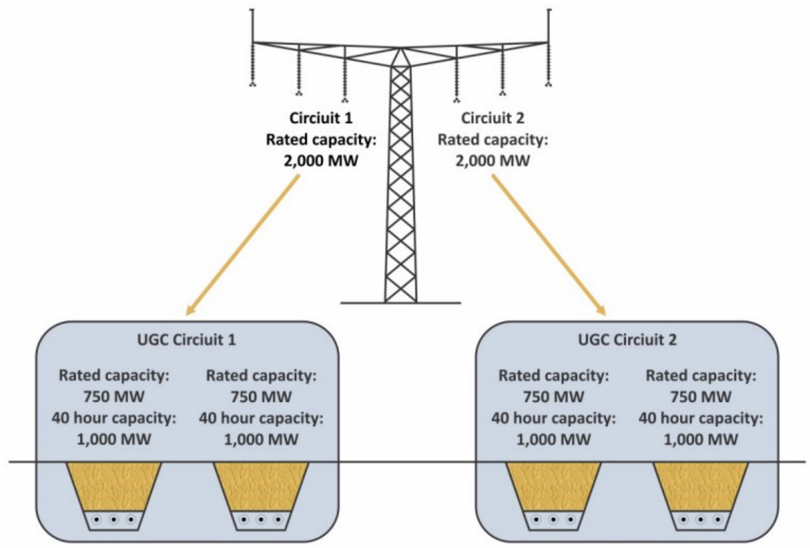


Figure 10: Comparison between AC capacity of an OH-lines and corresponding UGC (underground cable) [27]

Table 1: Technical data for OH-lines and cables [23], [27]

Technical data/General			**Comment**
Energy losses			
(Typical values, depend on length, layout, conductor material, impedance, ampere, compensation etc.)	Energy losses HVAC OH line	5%/100 km (Ref.1)	At rated power, with compensation
	Energy loss HVDC OH line	1%/100 km (Ref. 1)	At rated power
	HVDC converter loss (per end)	1-2 %	
	Energy loss HVAC cable	5%/100 km	At rated power, with compensation
	Energy loss HVDC cable	1%/100 km	At rated power
	Energy loss Transformer	1-2 %	
Capacity (AC)- typical values (depend on conductor and max. ampere). With compensation.			
OH-lines	110-150 kV 2 circuits	1100 MW	
	220 kV 1 circuit	1100 MW	
	220 kV 2 circuits	2200 MW	
	330 kV 2 circuits	3300 MW	
	380-400 kV 1 circuit	2000 MW	
	400 kV 2 circuits	4000 MW	
Underground cables	110 - 150 kV 1 circuit	210 MW	280 MW (40 hours load)
	110 - 150 kV 2 circuits	420 MW	560 MW (40 hours load)
	220 - 225 kV 1 circuit	420 MW	560 MW (40 hours load)
	220 - 225 kV 2 circuits	840 MW	1120 MW (40 hours load)
	300 - 500 kV 1 circuit	750 MW	1000 MW (40 hours load)
References			
	1. Comparative evaluation of power loss in HVAC and HVDC (2016)		
	https://www.researchgate.net/publication/313587347		

OH-lines - AC and DC

Table 2 presents economic data for OH-Lines. Some data are based on [28], which are ACER´s recent (2023) investment cost indicators. The original data from [28] are in the unit MEUR/km (upper part of table). By using the capacities from Table 1, the costs can be calculated in kEUR/km/MW (as shown). Low and high prices in Table 3 correspond 25 and 75 percentiles of data samples.

(Netz, 2021) provide data for AC and DC and (Balmorel, 2022) has data for DC. Figures for 2025 are estimated by adding 20% to the price from the source (2020 price level). The 20% is an estimate based on informal talks with industry stakeholders in the power transmission sector. The increase is explained by higher material cost, supply chain bottlenecks etc.

Table 2: Economic data for OH-Lines, AC and DC (references in the bottom of the table)

OH lines						2020 price level		Size of data sample	Reference	Comment
			Original price fro	Original, from source: Low	Original from, source: High	Pice from source	2025			
ACER, pwc, UIC, 2023	Overhead line (MEUR/km)- AC	110-150 kV 2 circuits	0,32	0,22	0,39	0,29		3	1	1,2
		220 kV 1 circuit	0,41	0,30	0,54	0,37		7	1	1,2
		220 kV 2 circuits	0,53	0,44	0,67	0,47		21	1	1,2
		330 kV 2 circuits	0,57	0,52	0,57	0,51		5	1	1,2
		380-400 kV 1 circuit	0,47	0,30	0,61	0,42		18	1	1,2
		400 kV 2 circuits	1,26	0,53	1,63	1,13		45	1	1,2
	Overhead line (kEUR/km/MW)- AC									
1100	MW	110-150 kV 2 circuits	0,30	0,20	0,36	0,26		3	1	1,2
1100	MW	220 kV 1 circuit	0,37	0,28	0,49	0,33		7	1	1,2
2200	MW	220 kV 2 circuits	0,24	0,20	0,31	0,22		21	1	1,2
3300	MW	330 kV 2 circuits	0,17	0,16	0,17	0,16		5	1	1,2
2000	MW	380-400 kV 1 circuit	0,23	0,15	0,30	0,21		18	1	1,2
4000	MW	400 kV 2 circuits	0,32	0,13	0,41	0,28		45	1	1,2
Netz, 2021	Overhead line (MEUR/km)- AC	380 kV, 2 circuits-AC	2,50			2,49			3	2
	4000 MW OH line AC (kEUR/km/MW)	381 kV, 2 circuits-AC	0,63			**0,62**	**0,75**		3	2
Netz, 2021	Overhead line (MEUR/km) DC	2 circuits; 2 GW per circuit	2,00			1,99			3	2
	4000 MW (kEUR/km/MW) DC	2 circuits	0,50			**0,50**	**0,60**		3	2
Balmorel model, 2022	Overhead line - DC-kEUR/km/MW		0,76			0,74			2	3
References										
	1. Unit Investment Cost Indicators - Project Support to ACER. Final report, pwc, Sept. 2023									
	2. Balmorel Model assumptions									
	3. Netzentwicklungsplan Strom (German TSOs), version 2021									
Comment	1. Low and high prices correspond to the 25 and 75 pencentiles of the data sample									
	2. 2025 prices are calculated by adding 20% to price from source									
	3. Balmorel 2022 data have already been lifted									

The data from (Netz, 2021) is selected for the price forecast. The argument is that (Netz, 2021) provide figures which must be assumed to be consistent between AC and DC, 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.

Table 3: Cost forecast for OH-Lines, AC and DC

OH lines, 2020 price level													
		2025	**2025 low**	**2025 high**	**2030**	**2035**	**2040**	**2045**	**2050**	**2050 low**	**2050 high**	**Reference**	**Comment**
OH lines AC	kEUR/km/MW (4000 MW capacity)	0,75	0,58	0,98	0,75	0,72	0,68	0,65	0,62	0,48	0,80	1	1,2,3,4
OH lines DC	kEUR/km/MW (4000 MW capacity)	0,60	0,46	0,78	0,60	0,58	0,55	0,53	0,50	0,38	0,65	1	1,2,3,4
References													
	1. Netzentwicklungsplan Strom (German TSOs), version 2021												
Comment													
	1. Low and high are minus/plus 30%												
	2. 2025 prices: after adding 20% to price from source												
	3. Prices in 2050 assumed to be as prices before 20% increase in 2025												
	4. Prices assumed to decrease linearly from 2030 to 2050												

Table 3 presents the cost forecast for OH-Lines, AC and DC. The costs are assumed unchanged until 2030. From 2030 to 2050 the prices are assumed to decrease (until the level before the 2025 uplift). The uncertainty interval (high and low values) is assumed to be plus/minus 30%.

Economic data for AC and DC cables onshore and offshore

Table 4 presents the collected data for cables from different references, see bottom of table. Data are in the unit MEUR/km or in kEUR/km/MW. The different categories AC/DC and onshore/offshore are indicated by different colours.

Where shown, low and high correspond to the 25 and 75 percentiles of the data samples, respectively.

For AC underground cables the original data from (ACER,pwc) are in unit mEUR/km. By using the capacities from table 1, the costs can be calculated in kEUR/km/MW, as shown in the table.

Table 4: Economic data for AC and DC cables, onshore and offshore (references in the bottom of the table)

Cables							2020 price level		Size of data sample	Reference	Comment
				Original price from source	Original from source, low	Original from source , high	Price from source	2025			
ACER, pwc, UIC, 2023	**AC, Onshore underground cable**	110 - 150 kV 1 circuit	mEUR/km	0,83	0,43	0,64	0,74		14	1	1
		110 - 150 kV 2 circuits	mEUR/km	2,23	0,85	3,06	2,00		4	1	1
		220 - 225 kV 1 circuit	mEUR/km	1,78	1,23	2,11	1,59		16	1	1
		220 - 225 kV 2 circuits	mEUR/km	4,40	4,23	4,56	3,93		4	1	1
		300 - 500 kV 1 circuit	mEUR/km	1,31	1,05	1,39	1,17		4	1	1
280	MW	110 - 150 kV 1 circuit	kEUR/km/MW	2,97	1,54	2,29	2,65		14	1	1
560	MW	110 - 150 kV 2 circuits	kEUR/km/MW	3,99	1,52	5,46	3,56		4	1	1
560	MW	220 - 225 kV 1 circuit	kEUR/km/MW	3,18	2,20	3,77	2,84		16	1	1
1120	MW	220 - 225 kV 2 circuits	kEUR/km/MW	3,93	3,78	4,07	3,51		4	1	1
1000	MW	300 - 500 kV 1 circuit	kEUR/km/MW	1,31	1,05	1,39	1,17		4	1	1
Netz, 2023 prices	AC, 220 kV cable system, onshore		mEUR/km	2,10						5	
	AC, 220 kV cable system, onshore	500 MW	kEUR/km/MW	4,20			**3,75**	**4,51**		5	2,3
	AC Offshore cable										
NETZ, 2021 prices	AC cable system 220 kV (offshore) Baltic Sea		mEUR/km	2,90			2,89			2	
NETZ, 2023 prices	AC cable system 220 kV (offshore) Baltic Sea		mEUR/km	2,10			1,88			5	
NETZ, 2023 prices	AC cable system 220 kV (offshore) Baltic Sea	500 MW	kEUR/km/MW	4,20			**3,75**	**4,51**		5	2,3
NETZ, 2021 prices	AC cable system 155 kV (offshore) Nord Sea		mEUR/km	1,50			1,49			2	
ACER, pwc, UIC, 2023	**AC Offshore cable (132-380 kV)**		mEUR/km	2,01			1,79		9	1	
Balmorel, 2022 prices	**AC Offshore cable**		kEUR/km/MW	1,96			1,90			3	
NETZ, 2021 prices	**DC onshore cable, 525 kV Nord Sea**		mEUR/km	6,50			6,47			2	
NETZ, 2023 prices	DC onshore cable, 525 kV Nord Sea and Baltic Sea		mEUR/km	7,60			6,79			5	
NETZ, 2023 prices	DC cable system 525 kV (onshore) (bipole)	2000 MW	kEUR/km/MW)	3,80			**3,40**	**4,07**		5	2,4
Balmorel, 2022 prices	**DC onshore cables**		kEUR/(km*MW)	1,74			1,69			3	
ACER 2023 prices	**DC offshore cable (300-500 kV)**		mEUR/km	1,11			0,99		6	1	
	Offshore transmission cable, 150-320 kV (AC?, DC?- unclear)		mEUR/km	3,29			2,94		7	1	
NETZ 2021 prices	**DC offshore** cable system, 525 kV Nord Sea		mEUR/km	4,00			3,98			2	
NETZ 2023 prices	DC offshore cable system, 525 kV Nord Sea and Baltic Sea		mEUR/km	6,00			5,36			5	
NETZ 2023 prices	DC offshore cable system, 525 kV (bipole)	2000 MW	kEUR/km/MW	3,00			**2,68**	**3,22**		5	2,4
NETZ 2021 prices	DC offshore cable system, 525 kV Nord Sea and Baltic Sea		mEUR/km	2,00			1,99			2	
2024 ENTSO-E planning p	**DC offshore cables**		kEUR/(km*MW)	1,62			1,40			4	
Tyndp 2022-project prom	**DC offshore cables**		kEUR/(km*MW)	1,70			1,65			6	
DNV2021 prices	**DC offshore cables**										
	0,5 GW 525 kV Cable		mEUR/km	1,64			1,63			7	
	1 GW 525 kV Cable		mEUR/km	1,89			1,88			7	
	1,5 GW 525 kV Cable		mEUR/km	2,14			2,13			7	
	2 GW 525 kV cable		mEUR/km	2,47			2,46			7	
DNV2021 prices	**DC offshore cables**										
	0,5 GW 525 kV Cable		kEUR/km/MW	3,28			3,28			7	
	1 GW 525 kV Cable		kEUR/km/MW	1,89			1,89			7	
	1,5 GW 525 kV Cable		kEUR/km/MW	1,43			1,43			7	
	2 GW 525 kV cable		kEUR/km/MW	1,24			1,24			7	
Balmorel 2022 prices	**DC offshore cables**		kEUR/(km*MW)	2,13			2,06			3	
References											
	1. Unit Investment Cost Indicators - Project Support to ACER. Final report, pwc, Sept. 2023, https://www.acer.europa.eu/sites/default/files/documents/Publications/UIC_report_2023.pdf										
	2. Netzentwicklungsplan Strom (German TSOs), version 2021										
	3. Balmorel model data										
	4. ENTSO-E planning prices for TYNDP 2024										
	5. Netzentwicklungsplan Strom (German TSOs), version 2023										
	6. TYNDP 2022 project sheets (from project promoters)										
	7. Screening of possible hub concepts to integrate offshore wind capacity in the North Sea, DNV for DEA, 2021										
Comments	1. Low and High values are 25 and 75 percentiles of the sample										
	2. Shown 2025 prices estimated by adding 20 % to price from source										
	3. 220 kV with capacity of about 500 MW										
	4. 525 kV bipole with capacity 1500-2000 MW										

Table 5: Cost forecast, AC and DC, onshore and offshore cables

Cables, 2020 price level		2025	2025 low	2025 high	2030	2035	2040	2045	2050	2050 low	2050 high	Reference	Comment
AC onshore cables	kEUR/km/MW (500 MW capacity)	4,51	3,47	5,86	4,51	4,32	4,13	3,94	3,75	2,88	4,88	1	1,2,3,4
AC offshore cables	kEUR/km/MW (500 MW capacity)	4,51	3,47	5,86	4,51	4,32	4,13	3,94	3,75	2,88	4,88	1	1,2,3,4
DC onshore cables	kEUR/km/MW (1500-2000 MW capacity)	4,07	3,13	5,29	4,07	3,91	3,74	3,57	3,40	2,62	4,42	1	1,2,3,4
DC offshore cables	kEUR/km/MW (1500-2000 MW capacity)	3,22	2,48	4,19	3,22	3,09	2,95	2,82	2,68	2,06	3,48	1	1,2,3,4
References													
	1. Netzentwicklungsplan Strom (German TSOs), version 2023												
Comment													
	1. Low and high are minus/plus 30%												
	2. 2025 prices: adding 20% to price from source												
	3. Prices in 2050 assumed to be as prices before 20% increase in 2025												
	4. Prices assumed to decrease linearly from 2030 to 2050												

It follows from Table 4 that in general there is high variation in prices for each category. The prices therefore have a high uncertainty.

As basis for cost forecast the data from (Netz, 2023) is selected for 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 and German prices are assumed to be close to Danish/Nordic prices.

Where shown, figures for 2025 (2020 price level) are estimated by adding 20% to the price from the source (2020 price level). The 20% is an estimate based on informal talks with stakeholders in the power transmission sector primarily in Denmark and the assumption that part/most of the price rise over the last years has been reflected in the 2023 prices in the references. The increase is explained by higher material cost, supply chain bottlenecks etc.

Error! Reference source not found.5 summarizes the results. Prices are assumed unchanged from 2025 to 2030. From 2030 to 2050 the prices are assumed to decrease in real terms (2020 price-level) (until the level before the 2025 uplift). Thus, 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.

Economic data for substations

Table 6 presents the collected relevant data for substations from several references, see bottom of table. Different colours are used to indicate the different categories.

Where shown, low and high correspond to the 25 and 75 percentiles of the data samples, respectively. The range between the two percentiles give a good indication of the uncertainty.

The reference from (ACER, 2023) have many costs data stemming from the same projects but sorted due to different indicators. One indicator is number of bays in the substation. A bay is a set of equipment which connects a circuit into the substation. The more bays the bigger the substation. Other indicators used by (ACER, 2023) are kEUR/kV and kEUR/MVA. It can be confusing with so many different indicators but nevertheless the data is reported here to illustrate the spread and the difficulties encountered when comparing numbers from different references.

(ACER, 2023) data are shown for AIS New, AIS Updated/refurbished and GIS New. AIS means open air stations (air insulated stations), GIS refers to Gas Insulated Stations. In a GIS station the major conducting components are contained within a sealed environment.

It follows that (ACER, 2023) price data for AC substations often are significantly smaller than data from other sources, e.g., (Netz, 2023) data, often a factor of 3 in unit MEUR/MW. The reason for this discrepancy cannot be immediately explained. Therefore, the data from (ACER, 2023) has been discarded from further processing[21].

Balmorel prices for a DC substation plus platform (0.23+0.45 MEUR/MW) is in good agreement with the (Netz, 2023) data which is 0.63 MEUR/MW (price from source).

As basis for cost forecast the data from (Netz, 2023) is selected for substations. 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

[21] It can be noted that ENTSO-E (covering all of Europe) in their recent 2024 Offshore Network Development Plans also use (NETZ, 2023)-price data for Substations (AC and DC) for their analyses. [ENTSO-E TYNDP 2024 Offshore Network Development Plans – Methodology](#).

TSOs have large experience with substation costs from their many projects and German prices are assumed to be close to Danish/Nordic prices.

Where shown, figures for 2025 are estimated by adding 20% to the price from source (2020 price level). The 20% is an estimate based on informal talks with industry stakeholders in the power transmission sector and the assumption that part of the price rise over the last years has been reflected in the 2023 prices. The increase is explained by higher material cost, supply chain bottlenecks etc.

Table 6: Economic data for substations

Substations							**2020 price level**				
				Original price from source	**Original, low**	**Original, high**	**Price from source**	**2025**	**Size of data sample**	**Reference**	**Comment**
ACER, 2023 prices	Onshore AC substation	0-5 bays, all	mEUR/asset	5,31	2,20	6,70	4,74		77	1	1
		New/AIS/maximum 5 bays		11,71	3,59	16,91	10,47		24	1	
		New/GIS/maximum 5 bays		13,62	5,40	15,99	12,18		8	1	
		Refurbishment or Upgrade/AIS/maximum 5 bays		3,40	2,12	4,30	3,04		28	1	
		Refurbishment or Upgrade/GIS/maximum 5 bays		4,45	1,00	6,40	3,98		13	1	
		6-9 bays, all		12,59	7,88	16,41	11,25		62	1	
		New/AIS/from 6 to 9 bays		12,14	8,18	16,68	10,85		24	1	
		New/GIS/from 6 to 9 bays		9,82	7,82	11,53	8,78		20	1	
		Refurbishment or Upgrade/AIS/from 6 to 9 bays		15,38	6,81	23,44	13,75		14	1	
		10-60 bays, all		29,85	19,26	40,33	26,68		23	1	
		10-60 bays , New		43,57	22,72	58,86	38,95		13	1	
		10-60 bays Refurbishment/upgrade		29,85	20,88	41,92	26,68		10	1	
ACER, 2023 prices	Onshore AC substation	All	kEUR/kV	31,25	16,68	43,45	27,93		118	1	3
		AIS New		31,72	18,52	43,62	28,36		48	1	4
		AIS updated/Refurbished		27,57	12,33	45,26	24,64		33	1	
		GIS New		35,11	27,68	42,31	31,38		26	1	5
ACER, 2023 prices	Onshore AC substation	All	kEUR/MVA	68,82	37,58	93,13	61,53		44	1	2
		AIS New		65,88	43,41	81,89	58,90		19	1	
		AIS updated/Refurbished		50,03	23,46	70,73	44,72		16	1	
		GIS New		123,68	93,48	133,74	110,56		8	1	
ACER, 2023 prices	Onshore AC substation	220-275 kV	mEUR/bay	1,21	0,84	1,52	1,08		48	1	
		300-330 kV		1,21	1,05	1,37	1,08		4	1	
		380-400 kV		3,38	1,15	5,24	3,02		56	1	
Netz, 2023	**AC onshore substation, 220 kV**		mEUR/MW	0,24			**0,21**	**0,25**		4	7,8
ACER, 2023 prices	AC Offshore substation		mEUR/asset	133,07	104,73	154,83	118,96		6	1	
Netz, 2023	**AC offshore substation, 220 kV (with platform)**		mEUR/MW	0,56			**0,50**	**0,60**		4	7,8
NETZ, 2021 prices	AC (Offshore +Onshore station)/2	Baltic Sea	mEUR/MW	0,35			0,35			2	6
NETZ, 2023 prices	AC (Offshore +Onshore station)/2	220 kV, AC, Baltic SEA	mEUR/MW	0,40			0,36			4	6
NETZ, 2021 prices	DC (offshore +onshore station)/2, 320 kV (with AC/DC converter)	North Sea	mEUR/MW	0,50			0,50			2	6 -
NETZ, 2021 prices	DC (onshore +offshore station)/2, 525 kV (with AC/DC converter)	North Sea	mEUR/MW	0,38			0,38			2	6
NETZ, 2023 prices	**DC onshore 525 kV station with converter (AC/DC)**	North Sea and Baltic Sea	mEUR/MW	0,30			**0,27**	**0,32**		4	7,9
NETZ, 2023 prices	**DC offshore station 525 kV with converter (AC/DC), incl. platform**	North Sea and Baltic Sea	mEUR/MW	0,70			**0,63**	**0,75**		4	7,9
ENTSO-E-planning prices 2024	Onshore DC station with converter (AC/DC)		mEUR/MW	0,25			0,22			5	
Tyndp 2022-project promoters	Onshore DC station with converter (AC/DC)		mEUR/MW	0,15			0,14			6	
DNV 2021 prices	Onshore DC station with converter (AC/DC)	1 GW, 525 kV	mEUR/MW	0,18			0,18			7	
Balmorel 2022 prices	One DC/AC substation		mEUR/MW	0,24			**0,23**			3	
	Offshore platform AC (no substation)		mEUR/MW	0,15			0,15			3	
	Offshore platform DC (no substation)		mEUR/MW	0,47			**0,45**			3	
Comments											
	1. Substation bay: A set of equipment which connects a circuit into a substation.										
	2. MVA: Mega Volt Ampere measures the size of transformers/substations										
	3. kV is busbar rating										
	4. AIS: Air insulated substation (typical open air station).										
	5.GIS: In a gas insulated substation (GIS) the major conducting structures are contained within a sealed environment with a dielectric gas (SF6)										
	6.Half of one offshore + one onshore station										
	7. Prices for 2025 by adding 20% to price from source										
	8. 220 kV substation, capacity in the range of 500 MW										
	9. 525 kV HVDC substation, capacity in the range of 1500-2000 MW										
References											
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	2. Netzentwicklungsplan Strom (German TSOs), version 2021										
	3. Balmorel model data										
	4. Netzentwicklungsplan Strom (German TSOs), version 2023										
	5. ENTSO-E planning prices for TYNDP 2024										
	6. TYNDP 2022 project sheets (from project promoters)										
	7. Screening of possible hub concepts to integrate offshore wind capacity in the North Sea, DNV for DEA, 2021										

Table 7 summarizes the cost forecast. 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). The uncertainty interval (high and low values) is assumed to be plus/minus 30%.

Table 7: Cost forecast, substations

Substations, 2020 price level														
		Price from source	2025	2025 low	2025 high	2030	2035	2040	2045	2050	2050 low	2050 high	Reference	Comment
AC onshore substation	MEUR/MW (500 MW capacity)	0,21	**0,25**	0,19	0,33	0,25	0,24	0,23	0,22	0,21	0,16	0,27	1	1,2,3,4,5
AC offshore substation, incl. platform	MEUR/MW (500 MW capacity)	0,50	**0,60**	0,46	0,78	0,60	0,58	0,55	0,53	0,50	0,38	0,65	1	1,2,3,4,5
DC onshore substation with converter (AC/DC)	MEUR/MW (1500-2000 MW capacity)	0,27	**0,32**	0,25	0,42	0,32	0,30	0,29	0,28	0,27	0,21	0,35	1	1,2,3,4,6
DC offshore substation with converter (AC/DC), incl. platform	MEUR/MW (1500-2000 MW capacity)	0,63	**0,75**	0,58	0,98	0,75	0,72	0,69	0,66	0,63	0,48	0,82	1	1,2,3,4,6
References														
	1. Netzentwicklungsplan Strom (German TSOs), version 2023													
Comment														
	1. 2025 prices: adding 20% to "year of source " prices													
	2. Low and high: minus/plus 30%													
	3. Prices in 2050 assumed to be as prices before 20% increase in 2025													
	4. Prices assumed to decrease linearly from 2030 to 2050													
	5. AC substation includes transformers, switchgear, powerlines, compensation, control equipment etc.													
	6. DC substation includes converter, converter transforme	DC substation includes converter, converter transformers, AC switchgear and busbars, harmonic filters , lightning towers, ancillary plant etc												

Economic data for transformers

Table 8 shows economic data for transformers. Where shown, low and high prices correspond to the 25 and 75 percentiles of the data samples, respectively. The range between the two percentiles give a good indication of the uncertainty.

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

When comparing figures in kEUR/MVA it follows that (DNV, 2021) and (Netz, 2021) prices are significantly lower than (ACER, 2023).

It is also seen that (DNV, 2021) and (Netz, 2021) prices are in fairly good agreement.

As basis for cost performance the data from (Netz, 2021) is selected for transformers. The argument is that (Netz, 2021) provide figures from the German TSOs, who have large experience with transformers from their many projects and German prices are assumed to be close to Danish/Nordic prices. Besides (Netz) prices 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.

Error! Reference source not found.9 summarizes the cost forecast for transformers. 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). Thus, 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.

The uncertainty interval (high and low values) is assumed to be plus/minus 30%.

Table 8: Economic data for transformers

Transformers						2020 price level				
			Original price from source	Original low	Original high	Price from source	2025	Size of data sample	Reference	Comment
ACER, 2023 prices	150/60 kV	mEUR/asset	1,21	1,10	1,27	1,08		3	1	1
	220/66 kV	mEUR/asset	1,54	1,34	1,72	1,37		12	1	1
	400/110 kV	mEUR/asset	4,36	3,63	4,73	3,90		15	1	1
	400/220 kV	mEUR/asset	4,63	2,94	6,18	4,14		7	1	1
	150/60 kV	kEUR/MVA	63,80	51,26	88,79	57,04		3	1	1
	220/66 kV	kEUR/MVA	97,70	82,66	108,70	87,34		12	1	1
	400/110 kV	kEUR/MVA	76,80	57,39	92,83	68,66		15	1	1
	400/220 kV	kEUR/MVA	28,20	22,75	34,46	25,21		7	1	1
DNV, 2021 prices	210/30 kV, 700 MVA	mEUR/asset	7,50			7,46			2	
	210/30 kV, 500 MVA	mEUR/asset	5,10			5,08			2	
	210/30 kV, 700 MVA	kEUR/MVA	10,71			10,7			2	
	210/30 kV, 500 MVA	kEUR/MVA	10,20			10,2			2	
NETZ, 2021 prices										
	380/110 kV, 300 MVA	kEUR/MVA	17,33			**17,3**	**20,8**		3	2
	380/220 kV, 600 MVA	kEUR/MVA	13,33			**13,3**	**16,0**		3	2
	220/110 kV, 200 MVA	kEUR/MVA	17,50			**17,4**	**20,9**		3	2
Comments										
	1. Low and high are the 25 and 75 percentiles of the sample									
	2. 2025 prices obtained by adding 20% to price from source									
References										
	1. Unit Investment Cost Indicators - Project Support to ACER. Final report, pwc, Sept. 2023									
	2. Screening of possible hub concepts to integrate offshore wind capacity in the North Sea, DNV for DEA, 2021									
	3. Netzentwicklungsplan Strom (German TSOs), version 2021									

Table 9: Cost forecast, transformers

Transformers, 2020 price level													
		2025	2025 low	2025 high	2030	2035	2040	2045	2050	2050 low	2050 high	Reference	Comment
380/110 kV, 300 MVA	kEUR/MVA	**25,9**	19,9	33,7	25,9	23,8	21,6	19,5	17,3	13,3	22,5	1	1,2,3,4
380/220 kV, 600 MVA	kEUR/MVA	**19,9**	15,3	25,9	19,9	18,3	16,6	15,0	13,3	10,2	17,3	1	1,2,3,4
220/110 kV, 200 MVA	kEUR/MVA	**26,1**	20,1	33,9	26,1	23,9	21,8	19,6	17,4	13,4	22,6	1	1,2,3,4
References													
	1. Netzentwicklungsplan Strom (German TSOs), version 2021												
Comment													
	1. 2025 prices: adding 50% to price from source												
	2. Low and high: minus/plus 30%												
	3. Prices assumed to decrease linearly from 2030 to 2050												
	4. Prices in 2050 assumed to be as prices before 50% increase in 2025												

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).

Table 10 and Table 2 present economic data for compensation via capacitor banks, reactors, SVC and Statcoms. All figures are in kEUR/MVAr. The data in Table 10 is from US, MISO (system operator) [34]; the data in Table 2 is from Germany (Netzentwicklungsplan, version 2021) [32].

The cost figures in US can be problematic to use directly for European purposes due to possible differences in market and price structures. Also, the definition of the CAPEX is different in the two cases: Table 10 (US) figures include taxes and contingency etc., while Table 2 figures are the raw CAPEX costs (equipment, installation).

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

By comparing 2025 figures in
Table 10 with corresponding figures in Table 2 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.

As basis for cost performance the data from (Netz, 2021) is selected. This data is assumed to best represent European conditions. Also, as mentioned the US definition of CAPEX differs from the definition in this study.

Table 10: Economic data for compensation, US data

Compensation	2025 prices (price level 2020)										
	Voltage class	69 kV	115 kV	138 kV	161 kV	230 kV	345 kV	500 kV	765 kV	Reference	Comment
	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, Static VAr compensator (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 (DRAFT)										
Comments											
	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 US$: exchange rate in 2022 is 0,951 EUR/$;										
	4. Prices in 2025: addition of 20% to price from source										

Table 11: Economic data for compensation, European data (Germany)

Compensation								
					Price level 2020			
			Unit	Price, original from source	Price from source	2025	Reference	Comment
Netz,2021	380 kV, 100 MVAr	Capacitor bank	kEUR/MVAr	20	20	24	1	1
Netz,2021	380 kV, SVC	SVC	kEUR/MVAr	50	50	60	1	1
Netz,2021	380 kV, 100 MVAr	Reactor	kEUR/MVAr	21	21	25	1	1
Netz,2021	380 kV	STATCOM	kEUR/MVAr	130	129	155	1	1
References:								
	1. Netzentwicklungsplan Strom (German TSOs), version 2021							
Comment:								
	1. 2025 prices by adding 20% to price from source							

Table 12 summarizes the cost forecast for compensation, European data. 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). The uncertainty interval (high and low values) is assumed to be plus/minus 30%.

Table 12: Cost forecast, compensation, European data (Germany)

Compensation, 2020 price level													
		2025	2025 low	2025 high	2030	2035	2040	2045	2050	2050 low	2050 high	Reference	Comment
Capacitor bank	kEUR/MVAr	24	18	31	24	23	22	21	20	15	26	1	1,2,3,4
SVC	kEUR/MVAr	60	46	78	60	58	55	53	50	38	65	1	1,2,3,4
Reactor	kEUR/MVAr	25	19	33	25	24	23	22	21	16	27	1	1,2,3,4
STATCOM	kEUR/MVAr	155	119	202	155	148	142	135	129	99	168	1	1,2,3,4
References													
	1. Netzentwicklungsplan Strom (German TSOs), version 2021												
Comment													
	1. Low and high: minus/plus 30%												
	2. 2025 prices: adding 20% to price from source												
	3. Prices assumed to decrease linearly from 2030 to 2050												
	4. Prices in 2050 assumed to be as prices before 20% increase in 2025												

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). 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.

Table 13 lists some guiding values.

Table 13: O&M (percentage per year of CAPEX) in transmission systems [30], [31], [36], [42]

O&M in % of CAPEX			
OH lines (AC and DC)			1,5
Onshore HVDC cable			2,5
Offshore HVDC cable			2,5
Offshore HVDC converter station			1,5
Onshore HVDC converter station			0,7-1,5
Offshore AC substation			1,5
Onshore AC substation			1,5
Offshore AC cable			2,5
Onshore AC cable			2,5

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2 Distribution of natural gas

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Qualitative description

Brief technology description

General information on the natural gas network
The natural gas system in Denmark is divided into different levels. These are:

- Transmission at 80 bar
- Main distribution at 16-40 bar
- Distribution

An overview of the transmission and distribution lines is shown in Figure 1.

The transmission network will not be covered extensively, as it is beyond the scope of this section. For safety reasons an odorant is added to gas before it enters the main distribution system, see Figure 1. The odorant gives the gas its characteristic smell of gas.

Figure 2 shows that the gas network covers most of Denmark, except for some of the islands and a part around Aarhus and Djursland.

Besides the natural gas network, there are networks for town gas in Copenhagen and Aalborg. However, the town gas networks will not be covered, as they use a different gas pressure, convey town gas (today a mixture of natural gas and air) and are constructed in a different period of time as well as with a different technology.

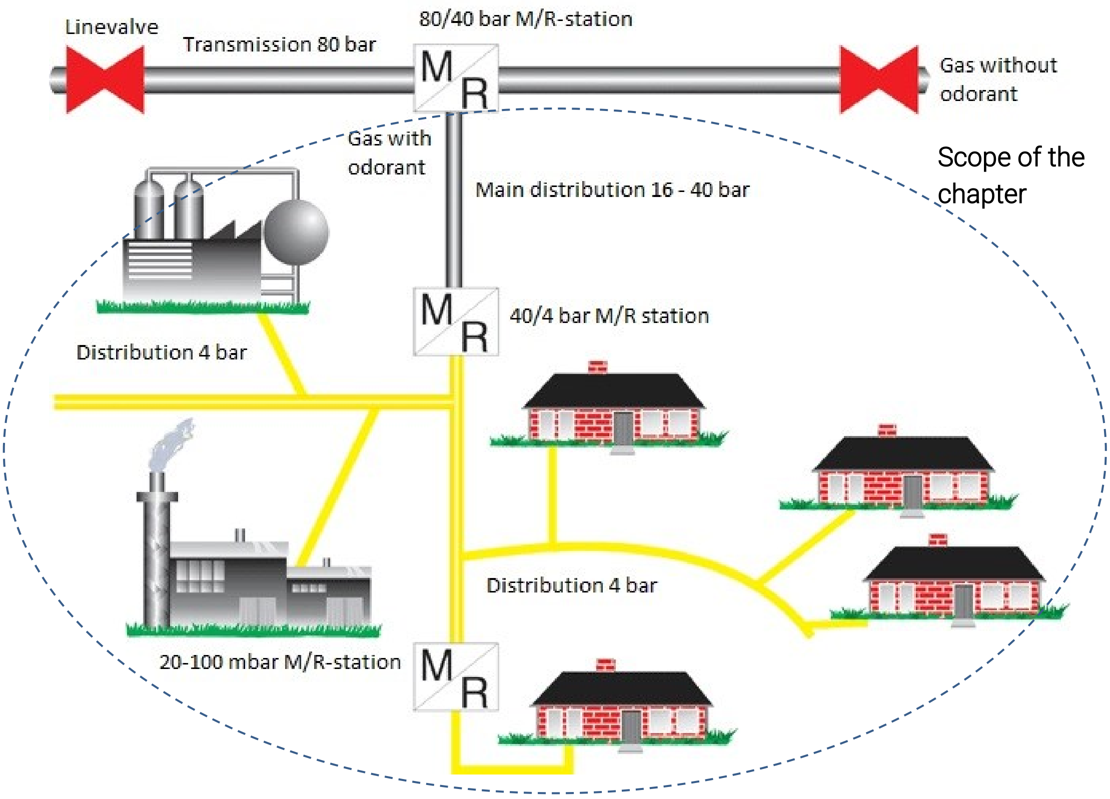

Figure 1 Overview of the gas network. Based on ref. [1].

Ownership of the network

Energinet, the Danish national transmission system operator for the natural gas system, owns and operates the transmission system. The distribution network, including main distribution lines, are owned and operated by the distribution companies.

When the natural gas network was planned, the network was divided into five areas:

- Northern part of Jutland
- Southern part of Jutland
- Funen
- Western part of Zealand
- Northern part of Zealand

However, some gas distribution companies have merged so that today there are currently three natural gas distribution companies:

- Dansk Gas Distribution A/S (Previously DONG Gas Distribution A/S)
- NGF Nature Energy Distribution A/S
- HMN Gasnet P/S

Their coverage can be seen in Figure 2, where the original division in five areas also can be perceived.

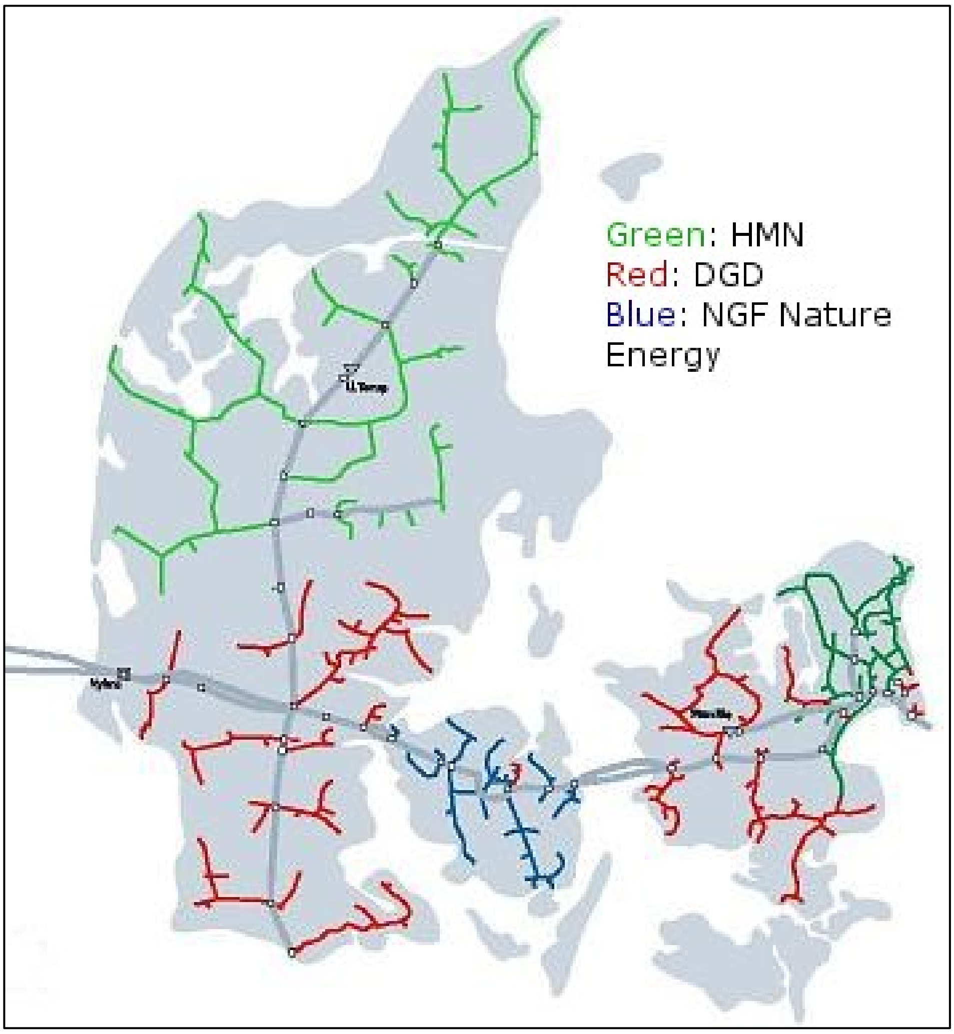

Figure 2 Geographical extent of the Danish transmission network (grey) and the main distribution network (green, red & blue). The colours refer to the companies operating the system.

Due to the described history of ownership, different designs and pressure levels exist in different parts of Denmark. The natural gas system contains pipelines operating at different pressure levels. The highest pressure is found in the gas transmission grid that operates at pressures of up to 80 bars. The maximum pressure in the main distribution grid varies among the gas distribution companies and regions (cf. Figure 2):

- HMN Jutland: 40 bar
- HMN Zealand: 19 or 40 bar
- DGD Jutland: 40 bar
- DGD Zealand: 19 bar
- NGF Nature Energy: 19 bar

Input

As of 2016, the main source of natural gas in Denmark is the North Sea where the natural gas is produced, mainly from the Tyra field. The natural gas is then transported from the North Sea to the onshore transmission network.

Besides the source in the North Sea, natural gas can also be imported from Germany. This part of the transmission line to Germany can be used both for import and for export.

The transmission network has five entry/exit points for natural gas:

- Nybro at the west coast of Jutland is the main entry point for Danish gas from North Sea gas fields.
- Ellund at the border to Germany is both an entry point for gas import and an exit point for gas export.
- Dragør near Copenhagen is the exit point for the gas export to Sweden.
- Stenlille on Zealand is one of the two Danish entry/exit points to a seasonal underground gas storage facility.
- Lille Torup in northern Jutland is another entry/exit point to a seasonal underground gas storage facility.

Since 2011, biogas upgraded to gas network quality has been injected into the gas network. From the start only at gas distribution level, but from 2016, biogas has been injected into the gas transmission network.

Output

The output is the same as the input, namely gas. As losses from the gas system are negligible, the amount of gas delivered from the gas network is basically the same as the amount delivered to it.

Energy balance

The energy consumption related to operation of the gas network is generally low. The network is supplied with natural gas at a sufficiently high pressure, so no further compression is required in the main distribution lines or in the distribution system. Therefore, the electric power consumption related to operation of the main distribution lines and the distribution system is as low as 0.005 % of the transported energy.

Reduction of the pressure in the system necessitates preheating, as the gas is cooled by the expansion. The heat is provided by burning an amount of gas corresponding to around 0.1 % of expanded gas. However, as there are different pressure levels in different parts of the country, preheating is not always required.

Description of the main distribution system

The main distribution system is supplied with gas from the transmission system. As mentioned earlier, the pressure in the transmission system is 80 bar. Before entering the main distribution system of the transmission system, the pressure is reduced to 19 or 40 bar depending on the geographical location. The pressure reduction takes place in MR (meter/regulator) stations.

- HMN Jutland: MR stations regulate pressure from 40 to 4 bar.
- HMN Zealand: MR stations regulate from both 40 and 19 bar down to 4 bar.
- DGD Jutland: MR stations regulate pressure from 40 to 4 bar.
- DGD Zealand: MR stations regulate pressure from 19 to 4 bar.
- NGF Nature Energy: MR stations regulate pressure from 19 to 4 bar.

As mentioned earlier, operation of MR stations with pressure reduction from 40 to 4 bar requires preheating, as the gas is cooled by the expansion. The heat is provided by burning an amount of gas corresponding to around 0.1 % of expanded gas. For MR stations with the more limited pressure reduction from 19 to 4 bar, preheating is not required. Instead, further preheating is required when the gas is expanded from 80 to 19 bar, compared to expanding from 80 to 40 bar.

The main distribution system supplies the 4 bar distribution network as well as a limited number of larger consumers, such as CHP plants and industrial customers. Due to the high pressure, the system is made of steel pipes.

Figure 3 Routing of gasline with distribution pipe. Source: HMN Gasnet.

Description of distribution system

Gas from the transmission system supplies the distribution system with gas at 4 bar. Before the gas enters gas installations, the pressure is reduced from 4 bar to 20 mbar, and the gas consumption is measured.

Figure 4 Cupboard containing pressure regulator and flowmeter mounted outside a private house.

In some areas, mainly the Greater Copenhagen area and the southern part of Jutland, Distribution Regulator stations (DR) reduce the gas pressure from 4 bar to 100 mbar before the gas is delivered to customers. However, all three gas distribution companies have stated that this will not be done for future networks, except for rare special cases [3][4][5]. Therefore, 100 mbar systems will not be treated further in this description.

Space requirement

The space requirement for the described system is limited to the MR stations. The space requirement for a 40/4 bar or 19/4 bar MR station is around 1,000 m^2.

Advantages/disadvantages

The gas system has a number of advantages.

It can be supplied with gases from various sources, including green gases, such as upgraded biogas and gases from power-to-gas processes, as long as the gas meets the natural gas specifications. It provides a large storage capacity corresponding to 2-3 months of consumption [1]. These properties may allow integration of large amounts of renewable energy in the energy system.

Furthermore, the gas system can provide very high power capacity compared to most other energy carriers, which is required by some parts of the industry [7]. The energy loss is very low compared to other energy distribution and transport systems.

The main disadvantage is that today the cost of producing green gases of natural gas quality from e.g. renewable power production is relatively high. Therefore, the only green gas in the Danish gas system is upgraded biogas.

Environment

Natural gas networks have a minimal environmental impact during the construction phase.

The environmental impacts during operation mainly consist of CO_2 emissions due to preheating at MR stations and minor losses of mainly methane during distribution of the gas.

There are no general data available on methane loss from the Danish gas system. If data from a European survey are applicable for the Danish system, the losses will correspond to 0.1 % of the amount of gas transported in gas networks. European gas networks are generally older than the Danish system. Therefore, it is expected that the losses from the Danish system are lower than the 0.1 %.

Research and development perspectives

Transportation and distribution of natural gas is a proven and efficient technology. Only little development is expected. The main development is expected to be in relation to green gas production and utilization of the gas.

Examples of market standard technology

The transmission lines and main distribution lines are made of steel pipes, whereas the 4 bar distribution system is made of PE pipes.

MR stations mostly consist of a redundant string with pressure regulators, meters (volume flow measurements) as well as pressure and temperature measurement and flow computer in order to determine gas flow at reference conditions.

If a distribution line is crossing a stream, a road or a railway directional drilling is often applied, which has made such crossings significantly cheaper than it was earlier.

Prediction of performance and costs

Prediction of cost and energy consumption is mainly based on the experience of HMN Gasnet.

Natural gas networks represent a mature and commercial technology with large deployment, corresponding to technological maturity level category 4. Therefore, prices have more or less stabilized over the last years. No significant changes in performance and costs are expected to happen to the technology in the foreseeable future.

Uncertainty

Data on construction costs for gas networks depend on a number of project specific details and are difficult to generalize.

Furthermore, if developments in e.g. directional drilling occur, they will impact costs in a way that is difficult to anticipate.

Additional remarks

The biogas' path to the Danish gas network

As mentioned earlier, today biogas is injected into the existing natural gas infrastructure. Costs related to biogas are not included in data stated in the data section.

What is biogas?

Biogas is produced by anaerobic digestion of biodegradable material. It consists mainly of 50-80 % methane and 20-50 % CO2. In addition, biogas contains low concentrations of undesirable substances, e.g. impurities, such as H2S, siloxanes, ammonia, oxygen and volatile organic carbons (VOC).

Biogas quality requirements

In order to be injected into the natural gas network or in order to be used in gas vehicles, the upgraded biogas quality must meet the same requirements as natural gas. In Denmark, these requirements are described in the Gas Regulations, section C12. The methane limit is not directly specified in C12, but can be deduced from the lower wobbe limit, which is 50.8 MJ/Nm^3. This equals a minimum methane content of 97.3 % assuming the rest is CO_2.

H_2S is limited to 5 mg/Nm^3. To avoid the risk of condensation, the water dew point up to 70 bar must be below minus 8 °C. Further requirements are given in the Gas Regulations, section C12.

Biogas upgrading

A large number of technologies are available for upgrading, but four technologies stand out as the clearly most common technologies

- Water scrubber
- Chemical scrubber (amine scrubber)
- Membrane scrubber
- PSA (Pressure Swing Absorption) scrubber

The technologies are further described in [8].

Biogas odorisation

Biogas must be odorized before entering a gas distribution network. The level of odorisation is the same as for natural gas, see C12. No odorisation is done, if the upgraded biogas is injected into the transmission system.

Injection points

Possible injection points

- Nearby 4 bar distribution network.
- Nearby 19-40 bar distribution network. Gas compression is needed before injection.
- Nearby 80 bar gas transmission network. Gas compression is needed before injection.

The selection of injection point(s) depends on

- Biogas plant capacity
- Local 4 bar gas distribution network base-load consumption
- Distance to nearby 4 bar gas distribution network
- Distance to nearby 19-40 bar gas distribution network

- Local 4 bar gas distribution network base-load consumption
- Distance to nearby 80 bar gas transmission network
- Cost of compression.

If the local gas consumption shows large variations during the day, a local intermediate storage facility can be used to increase the local consumption of biogas/upgraded biogas.

Selection of entry point(s) will be based on an economic optimization.

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3 Distribution and transmission of district heating

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Amendments after publication date

Date	Ref.	Description
Feb 2025	-	Updated chapter and datasheets. Datasheet for rural and LTDH removed

Qualitative description

Brief technology description

District heating (DH) is a water-based method of transporting heat energy, employing a piping network to deliver heat to both residential and commercial consumers. The technologies for generating this heat are diverse, including options such as combined heat and power plants (CHP), boilers, heat pumps, use of waste heat, and large-scale solar thermal plants, see the catalogue on Generation of Electricity and District heating for this. These systems often incorporate storage solutions to help balance the heat generation with consumption demands see the catalogue for Energy Storage for this.

Danish history of district heating in short

District heating has been used for more than 100 years in Denmark (Frederiksberg Forsyning, 2024), and has historically been based on different fuels to supply heat. In the 70's the energy supply was mainly based on oil, but war and crises influenced the oil prices, leading to an economic downturn in Denmark (Rosanna Farbøl, 2018).

These crises acted as a catalyst for change, leading to a transformative overhaul of the energy sectors in Denmark and other Western nations. A diverse energy supply system was introduced, reducing dependence on oil imports, and prompting a new focus on energy consumption practices. As shown in Figure 4, energy sources used to fuel DH changed from being primarily based on heavy fuel oil, to in 1990 being based on: natural gas, coal, waste, and biomass. In addition, more efficient energy utilization was achieved through significant increases in cogeneration in new and expanded DH networks, as the cost-effectiveness of DH networks was significantly improved through the development of pre-insulated pipes in the 1980s.

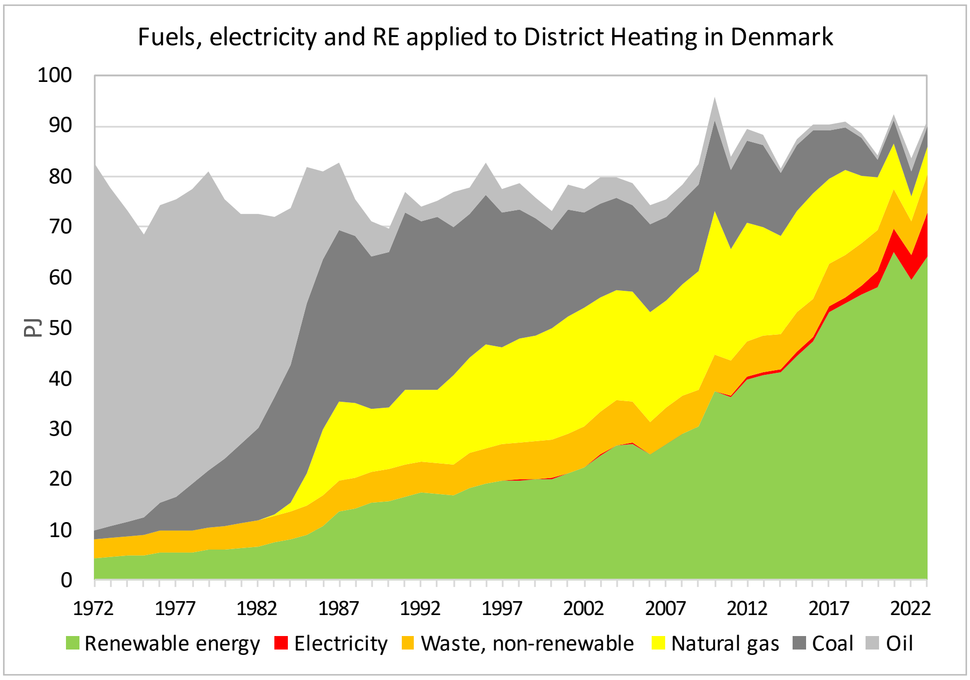

Figure 4 - Fuels applied in District Heating in Denmark. Kilde: Energistyrelsen – energistatistik 2023.

Input

Input to a DH network is heat in the form of hot water from various sources and based on various technologies, e.g. CHP plants, boilers, waste heat, large-scale solar heating plants, large electric heat pumps or electric boilers.

Output

The output is the same as the input, heat transferred through circulating hot water. However, due to heat distribution network losses the amount of heat delivered from the DH network is lower than the amount supplied to it.

Energy balance

Transportation of heat in DH pipes results in heat losses to the surroundings. The heat losses are dependent on the pipe lengths, the pipe insulation, and temperature difference between the pipes and their surroundings and varies a lot from one system to another. Average network losses are in the range of 15-20 %. In very large and dense systems, the loss can be as low as approximately 5 % while it can be more than 35 % in small systems with low heat density. These heat losses er inclusive losses in pump stations and heat exchanger stations. In large heat exchanger stations, efficiency is 98-99%. Heat losses in pumping stations are negligible. Heat exchanger stations are normally only found in connection with transmission networks. Most of the electricity for running the pumps is transformed to heat losses to the surroundings. A portion of this heat loss contributes to heating the DH water.

Transmission and distribution networks

Large DH systems are often set up with two different levels: transmission lines and distribution networks. The distribution network is distributing the energy at a lower pressure and temperature than the transmission line. A typical large DH setup is illustrated in Figure 5 below. In small scale DH networks, the transmission pipe would be replaced by a large distribution pipe.

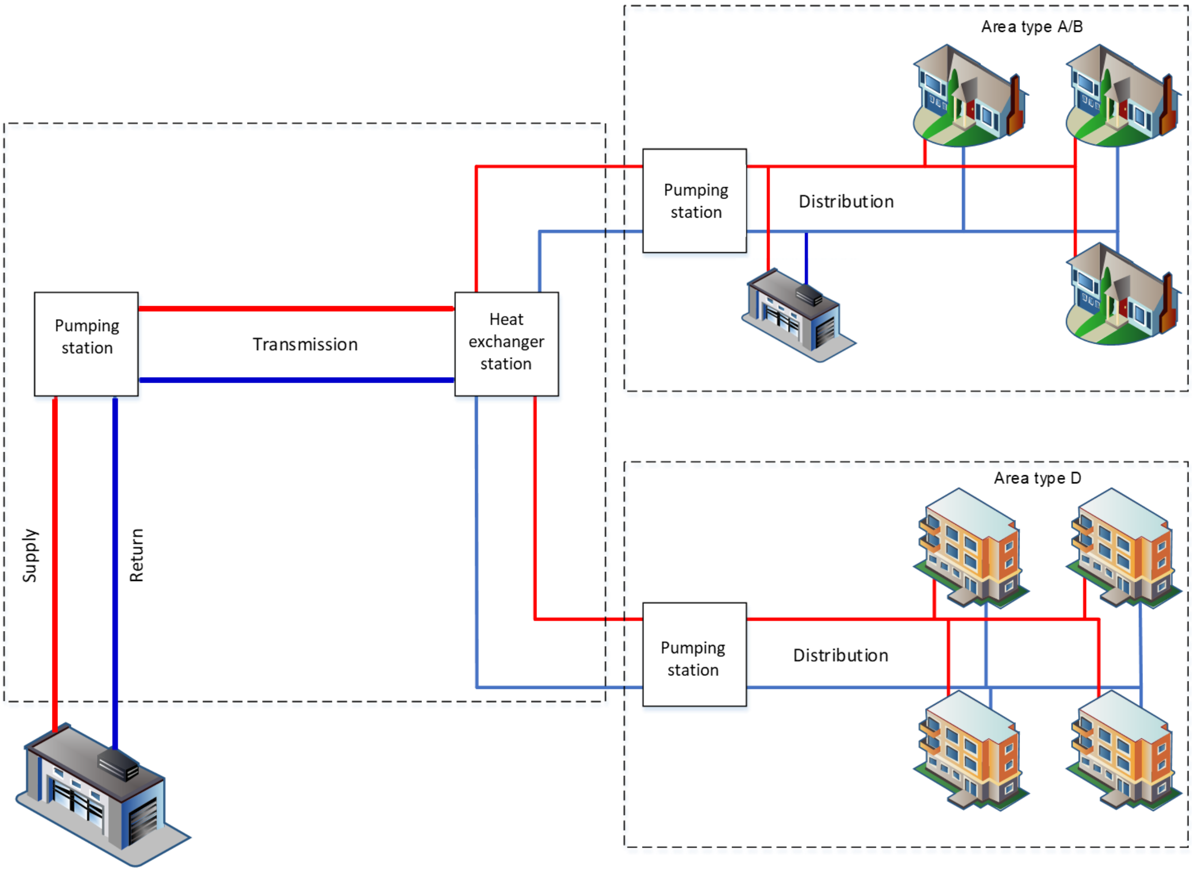

Figure 5 - District Heating Network

Description of the transmission system

DH transmission systems are used to transfer large quantities of heat between different distribution areas using water as a heat transfer fluid. Transmission systems operate at higher temperature and pressure levels (<110 °C and 25 bar) compared to distribution systems. However, when the heat is transferred to the distribution system, the pipes have a lower capacity to carry heat because the temperature is reduced. This lower temperature is beneficial, as it aligns better with the requirements of the customers' internal piping systems. Heat is typically transferred from transmission systems to distribution systems through heat exchanger stations to reduce the pressure and temperature levels.

A DH distribution system distributes heat to consumers in a distribution area using water as a heat transfer fluid. Distribution systems often operate with supply temperatures between 70-95 °C, and pressure levels between 6.5 and 16 bars.

However, due to an increasing attention to reducing temperature levels, to increase heat production efficiency and reduce heat loss, some areas operate at temperatures as low as 55-60 °C, mostly during the summer months. Development for lowering the supply temperature even further is ongoing but will require decoupling of space heating and domestic hot water production due to different temperature requirements for space heating and production of domestic hot water, e.g. floor heating only requires 30-35 °C whereas production of domestic hot water will require at least 50 °C to prevent the growth of legionella bacteria. This is typically solved either by a three-pipe system that allows a lower flow temperature for space heating while meeting the domestic hot water temperature requirement, or by installing a micro booster (small individual heat pump) to raise the domestic hot water temperature to the required level.

Operating at lower temperatures is more feasible in buildings erected after the 21th century, as new building codes supports this, e.g. by requiring higher insulation standards, and by the use of floor heating.

Space requirement for district heating pipes

The space required for the construction of the trenches for DH pipes varies depending on the ground conditions and whether it is a paved or unpaved area, but also on the size and type of pipes. To secure the trench walls from collapsing in unpaved areas, the trench walls are sloped thus increasing the trench width. Vertical trench walls, possibly with sheet piles, are typically used in paved areas. The space requirements are presented in **Error! Reference source not found.**. An e xplanation of the pipe types is given in the section: *Examples of market standard technology*.

Table 14 - Space requirements, span from the smallest (DN50) to largest distribution pipes (DN250).

Trench width requirements	Paved areas	Unpaved areas
Single Pipes	0.6 – 1.2 meter	1.75 - 2.4 meter
Twin Pipes	0.4 – 0.7 meter	1.5 - 1.8 meter

Advantages and disadvantages for district heating

District heating has a range of advantages and disadvantages that are critical to understand when planning and designing sustainable and efficient communities. This section explores the various benefits, such as energy efficiency and the possible ability to reduced environmental impact, alongside the potential drawbacks, like initial infrastructure costs and complexity of installation, that come with implementing district energy solutions. By evaluating these factors, stakeholders can make informed decisions that align with both economic and ecological objectives.

Advantages

1. Energy production optimization: urban settings benefits from centralized heating systems, which can switch between various production methods based on demand. Biomass and biogas can be advantageous during high electricity prices, especially with CHP systems that also generate power for sale. Equally, heat pumps and electric boilers become more advantageous when electricity costs drop.
2. Compatible with fluctuating energy sources: District energy systems can leverage renewable energy sources and waste heat, which can significantly reduce greenhouse gas emissions compared to individual heating and cooling solutions. If a DH system is connected to a heat storage and heat is produced at CHP plants, large heat pumps or large electric boilers, the DH system can offer flexibility services to the electricity network helping to integrate a higher share of intermittent power producing technologies e.g. wind and solar power. This is already happening today and will be even more important in the future as part of several other Smart Energy solutions.
3. Reliability: District energy systems can offer higher reliability and stability in energy supply due to redundancy measures. By different production units in the same network making it possible to prioritize the preferred heat production, e.g. the most efficient, economic, environmentally friendly etc.
4. Space Benefits: The heat interface unit, which connects the district heating to the internal heating system in buildings, normally requires less space than heating alternatives such as gas boilers and heat pumps.
5. Future-proof Infrastructure: District energy systems can adapt more easily to future energy sources and technologies compared to decentralized systems.
6. Peak Demand Management: Centralized systems can be more effective at managing and reducing peak energy demands, by means of storage facilities. The use of seasonal heat storage allows for the integration in the DH system of large-scale solar heating plants and hence takes advantage outside the summer season of the economically advantageous and CO_2-neutral solar heat.
7. Reduction in Infrastructure Complexity: Fewer individual systems mean reduced requirements for fuels, fuel storage, and maintenance infrastructure in each building.
8. Maintenance: It is a well-proven and reliable technology that offers easy operation for the heat consumers. Heating from district heating is as convenient for the consumer as any other utility (water, electricity) by moving the responsibility of operation and maintenance away from the consumer to professional service providers.
9. Sector-coupling: Heat pumps and electric boilers in DH systems can be used to absorb surplus electricity from wind and solar power, and can utilize heat from waste incineration (WtE) and industrial waste heat from emerging PtX industries and datacenters.

Disadvantages

1. High Initial Investment: The capital costs for establishing district energy infrastructure can be high, and the payback period of the investment is often very long.
2. Inflexibility: Once established, district energy systems can tie consumers to a particular energy source or provider, limiting their flexibility to switch.
3. Heat Losses: Energy can be lost during transmission from central plants to end-users, especially over long distances.
4. Geographical Limitations: District energy systems are most efficient in densely populated areas and may not be as practical or cost-effective in rural or sparsely populated areas.

Environment

The development of district heating in Denmark has taken place through the Heat Supply Act, which mandates to choose the cheapest socio-economic heat supply solution. This assessment includes the costs of air emissions that impact the climate and the local environment, supporting the development of environmentally sound solutions.

As with other construction works, environmental legislation and municipal regulations ensure that the establishment of DH networks has a minimal environmental impact during construction. This includes protection of sensitive nature and habitats, handling of noise and dust, handling of possibly contaminated soil, etc.

By centralizing heat production and through sector coupling with, e.g., the electricity system, DH systems can contribute to a more efficient use of energy resources. Examples of this include cogeneration at combined heat and power (CHP) plants, and heat production from large electric heat pumps and electric boilers.

The flexibility of DH systems includes the possibility of integrating various renewable and low-carbon heat sources, such as large-scale solar heating, geothermal energy, or waste heat from industrial processes. The flexibility is achieved by means of relatively cheap thermal storage solutions that allow temporal separation of heat production from consumption, enhancing the system's ability to balance and optimize the use of intermittent renewable energy sources.

Research and development perspectives

Research and development in district heating focus on making systems more efficient and integrated as part of a smart energy system.

Low-temperature district heating (LTDH), with a supply temperature of 50-55°C and a return of 25-30°C, is now a proven 4th-generation district heating technology. Recently, ultra-low-temperature district heating (ULTDH) has been introduced, with a supply temperature below 45°C and a return of 20-25°C. ULTDH separates district heating supply from domestic hot water (DHW) supply, using small individual heat pumps (micro boosters) to produce DHW, thus minimizing legionella risk. ULTDH is still developing but is promising for both new low-energy and some existing buildings.

Both LTDH and ULTDH provide advantages as lower heat losses, higher energy efficiency, e.g., for heat pumps, and compatibility with various heat sources, including renewable and industrial waste heat. LTDH and ULTDH are considered cost-effective, particularly in low-density, low-energy urban areas.

The trend toward low-temperature DH systems, as studied by the 4DH Research Centre (2024), highlights a shift towards more efficient, low-temperature networks that align with sustainable energy goals, as shown in Figure 6.

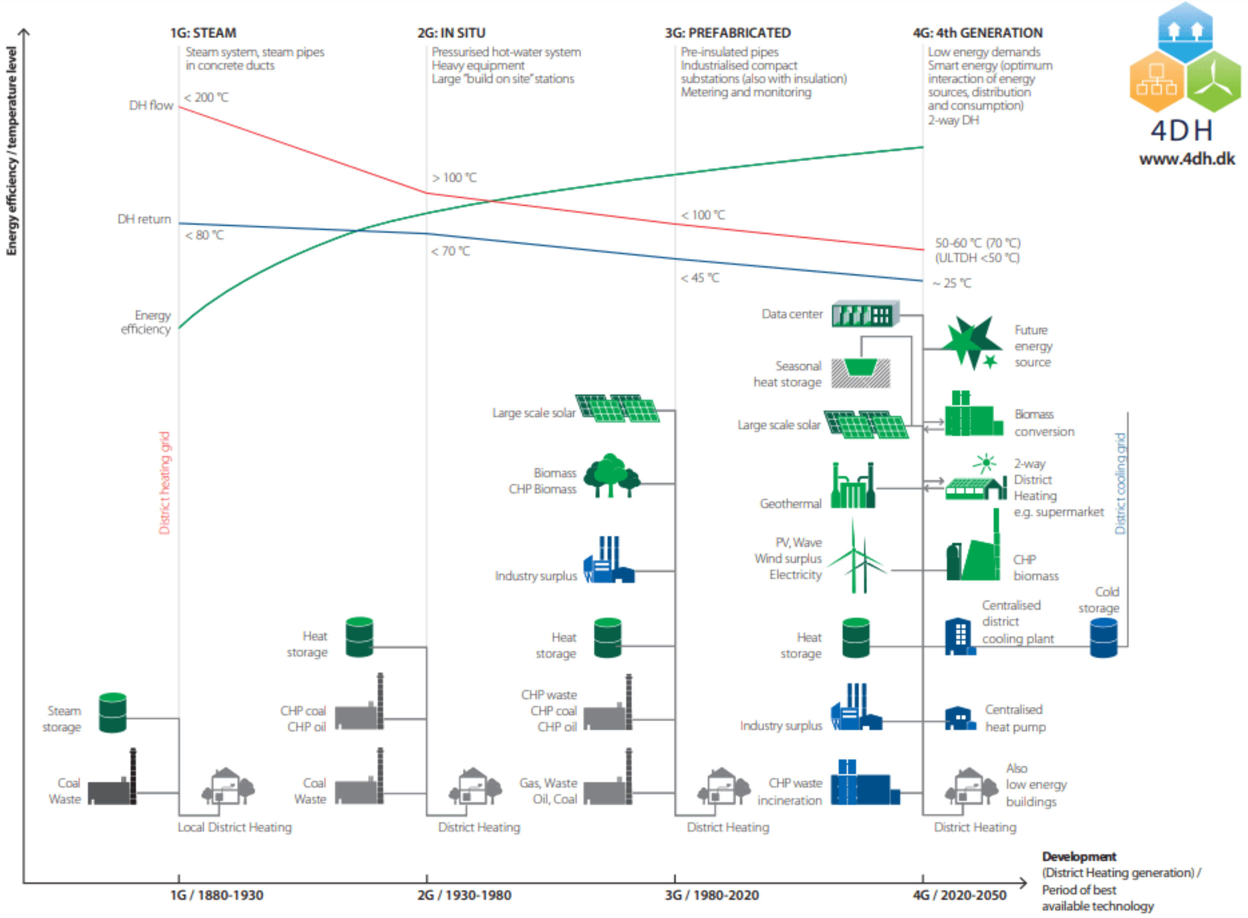

Figure 6 - Evolution in temperature reduction (4DH Research Centre, 2024). Note: DH flow is the same as DH supply.

Research and development efforts are also investigating how to best retrofit existing buildings to work with these new low-temperature heating systems since a large part of the building stock, with its long lifespan, will continue to be a significant driver for heat energy for decades to come.

Focus areas within R&D include improving material technology to reduce losses, enhancing the pipe installation processes by e.g. smarter sleeve joints, developing advanced control systems for better network management, and exploring how to use digital technologies like IoT and AI to optimize the operation of district heating across different sectors.

Examples of market standard technology

A central element of DH is the pipes used. They can be twin or single (number of pipes within same insulation) and both single and twin pipes are manufactured in a variety of different materials, such as steel, different plastic materials, copper, and aluminium.

Where possible, twin pipes should be used instead of single pipes as this ensures reduced heat losses as well as construction costs. However, in areas with a high altitude changes single pipe systems are preferred. The twin pipe systems are available in dimensions up to DN250 (nominal diameter) but are normally not used for dimensions above DN150, as larger sizes become inflexible and difficult to handle.

While steel pipes are normally used for larger dimensions, more flexible pipes are preferred for smaller dimensions (DN15-DN50). These flexible pipes are easier to install, e.g., at consumer sites, as they can be bent where it requires complex routing and require fewer joint and less welding.

There are various solutions from different manufacturers aimed at making piping systems more flexible. Many of these use plastic materials, such as PE (polyethylene) with a diffusion barrier of aluminium.

Figure 7 shows twin pipes made from different materials. The picture on the left is conventional steal pipe, that is non-flexible, while the picture at the right shows a flexible PE pipe.

Regardless of the choice of materials and functionality, DH systems must be designed for a service life of at least 30 years according to DS/EN 13941-1:2019.

Figure 7 - Twin pipes – Steel and flexible PE pipe

Quantitative description

As shown in Figure 8, price indices show that there has been an increase of 30% in current prices and 15% in real prices from 2020 to 2024 for establishing and expanding district heating networks. This increase reflects a turbulent economic period with high inflation, driven by factors such as the 2021-2023 energy crisis and supply chain disruptions following the Russian invasion of Ukraine (U.S. Bureau of Labor Statistics, 2024).

In addition, the limited growth in the number of available contractors for district heating projects has since 2022 contributed to the construction cost increase, as demand for new DH projects continues to outpace workforce expansion in the sector.

A future stabilization of construction costs is expected in line with recent price index trends, but the rising costs has raised concerns that this have made district heating less competitive compared to individual heat pumps. But the competitiveness will also depend on the general longer technical lifetime of district heating systems as well as the development of heat production costs, where other parameters come into play: Economies of scale in energy pricing for DH plants compared to small, individual heat users; utilization of fluctuating electricity prices through flexible operation of CHP plants and electrically driven heat pumps and electric boilers; the possibility of utilizing cheap waste heat from industrial processes, etc.

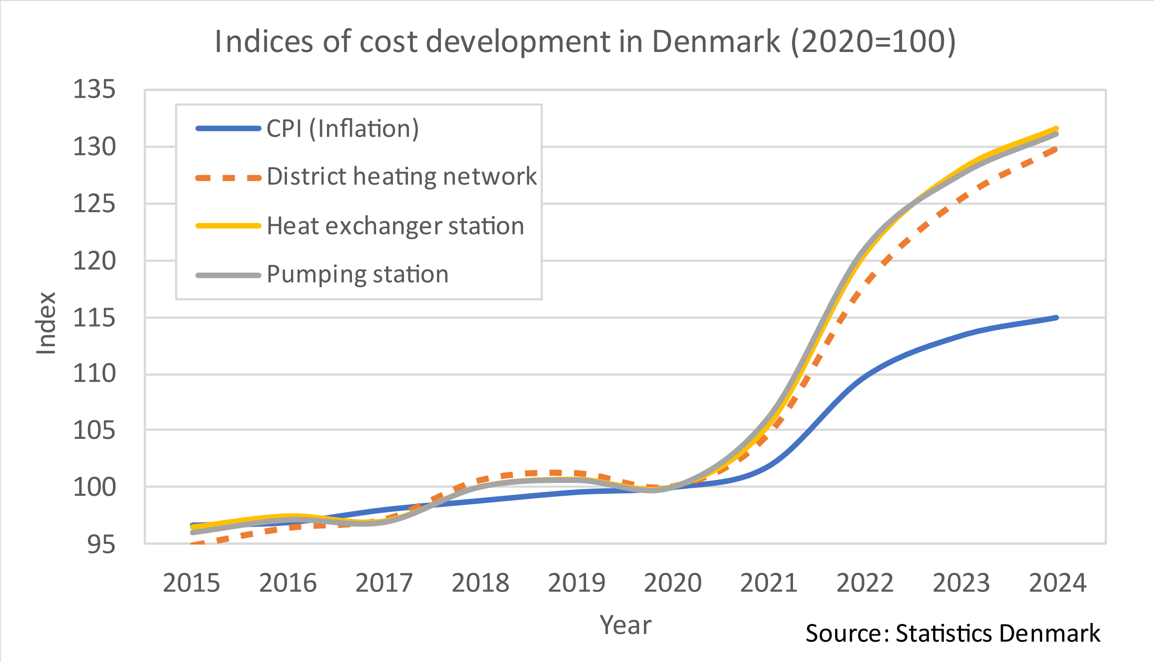

Figure 8 - Cost development 2015-2024 for district heating networks, large heat exchanger stations and pumping stations based on cost indexes from Statistics Denmark

Technology data

The technology data referred to in this catalogue is about pre-insulated pipe systems that meet the requirements of DS/EN standards for design and installation. Twin pipes are assumed for sizes up to DN150, while pipe pairs are chosen for larger dimensions. The data sheets are organized into four tables, each providing key figures for the following types and conditions:

1. DH transmission systems at high temperature and pressure levels (design 110 °C and 25 bar).
2. DH distribution networks in suburban areas: Medium populated areas with predominantly detached, single-family homes of 1-2 floors. Heat density around 10 GWh/year/km^2.
3. DH distribution networks in city areas: More densely populated areas, including traditional Danish provincial towns with mixed, closely packed buildings of 2-3 stories or newer apartment complexes up to 4-5 stories with open spaces around. City represents urban areas with a relatively low heat density (around 15 GWh/year/km^2) with potential for new district heating, as urban areas with higher heat density are assumed to already have district heating.
4. DH distribution networks in new areas: Newly developed clusters of 1-2 story homes with shared green areas. Key data for LTDH is also included due to a considerable potential in new areas. Heat density around 6,5 GWh/year/km^2.

As a mature technology, district heating costs are generally expected to remain stable in real terms, with future expenses for new pipelines, heat exchangers, and pumping stations anticipated to follow inflation trends, like the period before 2020. However, there is still potential to improve system efficiency and reduce heat loss by adopting still lower operating temperatures.

Uncertainties

Key cost figures and efficiency indicators for DH networks, including investment cost per meter or per MW, heat loss ratios, and expected technical lifespan, can vary significantly based on the unique characteristics of each project, making standardization complex. Moreover, significant modifications to the core design and operational processes of these systems can result in unforeseen impacts on both the resulting investment costs and overall performance.

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4 Transport of hydrogen by pipeline

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Qualitative description

Brief technology description

Hydrogen pipelines are relevant to transporting large volumes of hydrogen over both short, medium and long distances and are a key infrastructure to connect hydrogen producers and supply points (e.g. electrolyzes, import terminals) with hydrogen consumers and demand centres (e.g., industry, storage, export) across geographies.

The typical elements of hydrogen pipeline projects are:

- Pipeline: the main conduit for transporting hydrogen gas over distances. It connects hydrogen supply points (e.g., electrolysers, import terminals) to demand centres (e.g., industry, storage, export). Pipelines are typically buried and operate under high pressure to enable large volume flow with minimal energy loss. They are designed to safely contain hydrogen, manage pressure, and allow for inspection and maintenance.

- Stations: to ensure safe operation and maintenance of transport pipelines, several supporting and safeguarding components are installed along the route of pipeline. These are typically comprising compressors, line valves (LV), pig launcher/ receivers (PLR), control and measurement equipment.

Input

Input to hydrogen transport by pipeline is hydrogen gas, which is compressed and transported to the point of utilization or to a storage facility. Hydrogen gas quality is expected to be high enough for fuel-application. The hydrogen gas will be highly pure and dry with limitations on impurities (i.e. oxygen, water, nitrogen, total HC., etc). The acceptable water content of the gas is set very low to avoid any condensation of water in all operational events. The accepted limit of water may vary depending on the operational condition. The energy content of hydrogen gas used as energy-carrier is expressed in lower heating value (LHV). It is required that the energy content is accurately determined, so precise billing can be carried out at custody transfer points.

Output

Output from hydrogen transport by pipeline is hydrogen gas. As leakages from the pipeline transport system are negligible, the amount of hydrogen gas extracted from pipeline system is the same as the amount injected into it, regardless of whether this is a pipeline network or point-to-point pipeline. Flow in and out of the pipelines are to be determined by fiscal metering at entry and exit points, so adequate control of system balance exists on volumes transferred between different parties such as hydrogen source owner and transport/storage provider or off-taker in industrial production.

Energy balance

No energy is inherently lost in the pipeline transmission of hydrogen. However, there are three main cases, where energy is needed for compression in relation to the operation of the hydrogen transport system:

Pressure drop: in long pipelines the pressure of the hydrogen gas decreases due to resistance to flow. Hence, there can be some energy usage for booster compression to make up for the pressure drop and ensure a supply pressure at minimum operation levels. The exact distance between booster stations depends on pipeline diameter, volumetric flow rate, and the initial inlet pressure. In a theoretical example, 2 booster stations are needed along a 1.500 km long 36” pipeline operating at 70 barg [1].
An example for a transmission pipeline without the need for compression is the Danish Hydrogen Backbone, which is planned for “no compressor situation”. Such networks are supplied with sourced gas at a sufficiently high pressure, so no further compression is required in the main transmission system. Therefore, the electric power consumption related to operation of the main transmission and the distribution lines is a minimal part of the transported energy.

Inlet compression: compression at the production site before injection into the pipeline. The amount of energy required depends on factors like the delivery pressure of hydrogen at the production site (different electrolysis technologies operate at various pressure levels up to 40 barg) [2]. This condition influences the extent of additional compression.

Compression at junctions: e.g. if there are pressure differences between a branch and transmission line, compression is needed to ensure required supply pressure at the injection point.

Difference between transmission and distribution

A hydrogen pipeline system will, on a high level, consist of:

- Branch pipelines connecting producers and users to the transmission grid
- Distribution pipelines connecting producers to users in proximity to each other
- A transmission grid connecting distribution systems sometimes lying far apart

While hydrogen transmission and distribution networks share many technical characteristics—including similar types of stations, and design considerations, the main differences lie in pipeline size and operating pressure, as reported in Table 15.

Both types of pipelines rely on similar infrastructure elements such as LV stations, PLR stations, and injection/extraction points, though booster compression stations are generally more relevant for long-distance transmission lines or distribution grids. Installation methods, trenching, and safety measures are largely consistent across both pipeline types, with no significant differences in construction approach or regulatory requirements.

Pipeline dimensions and typical capacities

An overview of typical pipeline dimensions based on applications in the Danish context is reported in Table 15. Overall, pipelines with 8/10/12 and 20 inches (´´) in diameter can typically be suitable for regional distribution or branch pipelines. Pipelines with 20/30/36 inches in diameter can be suitable for transmission pipelines moving hydrogen between larger regions or countries. These are broad categories and the choice of pipeline diameter will depend on the specific conditions. In the current phase of the design of the DHB project, the expected pipe dimension of new built pipelines is 36`` in diameter, and the re-purposed pipeline is 30".

Table 15: Standard pipeline diameter and related application.

Pipeline diameter	Application
8 inches	To be considered for a branch pipeline for 500 MW electrolysis at high design pressure.
10 inches	To be considered as a branch pipeline depending on the size of the electrolysis unit and design pressure.
12 inches	To be considered for a branch pipeline for 1 GW electrolysis at high design pressure
20 inches	To be considered as a transmission line for small collective solutions
30 inches	Could be considered as a transmission line for medium-sized collective solutions
36 inches	Expected diameter for the DHB

Hydrogen pipelines can be designed with varying diameters based on the transport capacity requirements, system design parameters and allows for the adaptability of market needs with gas velocity being a critical factor which impacts both pipeline integrity and energy efficiency. High gas velocities can lead to vibrations, erosion, and increased pressure drops, especially near pipeline discontinuities and at stations. These pressure drops drive up compression energy costs and can compromise reliability.

Key steps in hydrogen pipeline system design are the following:

- Set the velocity limit based on acceptable energy transport capacity, pressure drop, and risk of erosion or vibration.
- Select the outer diameter that meets flow and pressure requirements while adhering to commercial availability and design standards.

- Assess energy storage and transport potential under varying pressure and flow conditions.

These three steps are described further.

Velocity Limits

Determining an appropriate velocity limit is a critical design factor that impacts the overall efficiency, safety, and lifespan of the pipeline system. Unlike more established gas pipeline systems, hydrogen transmission currently lacks clearly defined industry standards for velocity criteria. In the absence of such benchmarks, velocity selection requires careful analysis and engineering judgment to identify an optimal value.

Hydrogen requires higher flow velocities than natural gas (typically ranging 10-15 m/s for the operational acceptable velocity) to transport the same amount of energy, due to its lower volumetric energy content. Also, hydrogen is less sensitive to pressure drop, allowing for higher flow rates - up to 3 times that of natural gas-without compromising efficiency. The stated limit will still comply with accepted risk level posed by high velocities concerning retaining pipe integrity, environment and safety.

A COWI model suggests, that for hydrogen pipelines, a limit for the operational velocity between 30 to 50 m/s is recommended. This ensures sufficient energy transport capacity while minimizing pressure drop and avoiding mechanical stress. For pipeline stations, a more conservative limit of 20 m/s is suggested to reduce risks associated with noise, erosion, and vibration in sensitive areas.

Sizing the pipeline should ensure that the velocity and pressure drop limits are not surpassed at any location. The highest velocities often happen at the end of the pipe, where the pressure is lowest. Once upstream and downstream pressure conditions are defined, they constrain the allowable flow velocity and directly influence the required pipeline diameter. This makes early verification of velocity limits essential in the sizing process.

Initial sizing based on gas velocity determines the theoretical minimum inner diameter required to ensure inlet and outlet pressure to the pipeline. The final pipeline dimensions are to be defined iteratively, considering the required wall thickness for the pressure level, commercially available sizes, pressure drop and other design considerations and safety standards.

Pipe diameter and energy transport capacity

The energy transport capacity of a gas with a fixed composition is primarily determined by its thermodynamic state, pressure and temperature, which determine density, and gas flow related elements such as velocity and pipeline diameter[1]. Together, these factors determine the mass flow rate and, in turn, the amount of energy that can be transported in the constructed pipeline.

[1] The energy transport capacity (E) for hydrogen can be assumed to be a function of essentially three main elements at any point in the pipeline: operating pressure (P), velocity (ʋ), and pipe's inner diameter (D), as the temperature effect on density can be disregarded. This is illustrated by: $E = \rho(P) \times \, v \times \, LHV \times \, \frac{\pi}{4} D^2$

As an example, the energy transport capacity as a function of operating pressure and nominal diameter is shown in Figure 9 and Figure 10 for two different velocities.

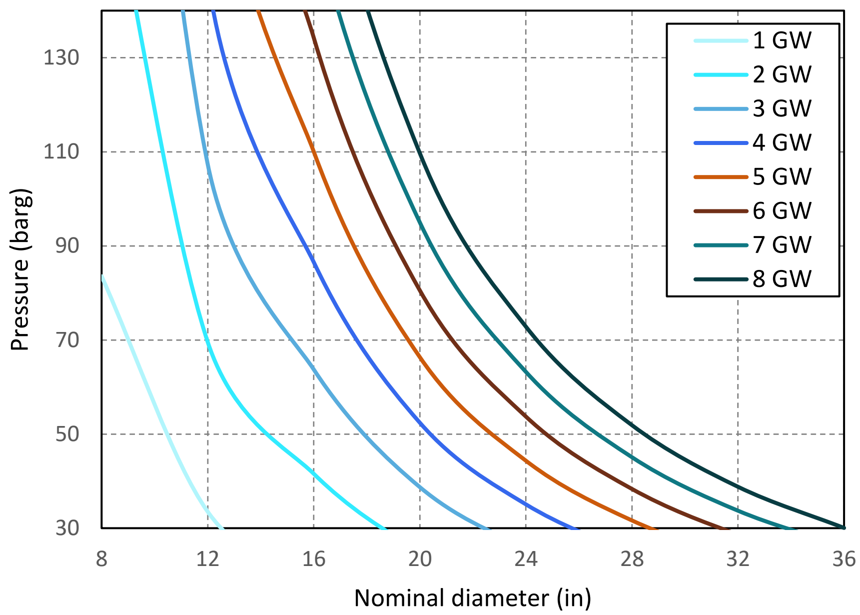

Figure 9. Energy transport capacity for different Nominal Pipe Sizes within the operating pressure range at 40 m/s velocity.

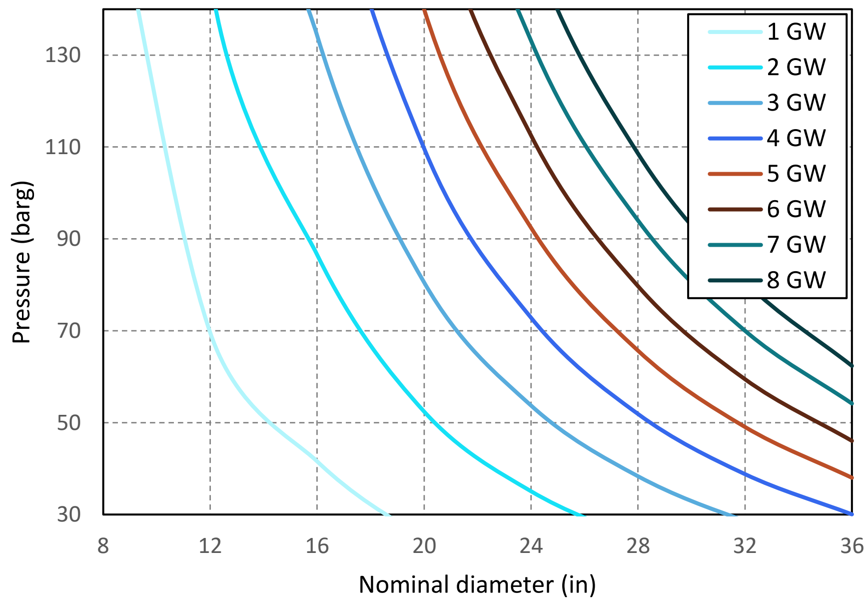

Figure 10. Energy transport capacity for different Nominal Pipe Sizes within the operating pressure range at 20 m/s velocity.

Relevant pressure levels and pressure loss

Typical operational pressure reference levels for hydrogen pipelines are 40, 90 and 140 barg. These pressure levels cover maximum operating pressures (MAOP) while often pipelines are designed to withstand slightly higher design pressure, considering a smaller design margin. The cost of a pipe is driven by design conditions, which determine the required thickness and, consequently, the quantity and cost of materials needed for supply and installation.

Increasing the pressure in the pipeline allows for greater hydrogen transport capacity due to raise in density. However, it also leads to higher costs due to the need for thicker-walled pipes to work under higher internal pressure, more powerful compressor systems, and stricter safety and material requirements, particularly to mitigate hydrogen embrittlement and ensure long-term integrity. Existing industrial hydrogen pipelines often operate at ~40 barg. The future European Hydrogen Backbone lines are expected to be operated between 60–90 barg. While international standards allow hydrogen pipeline pressures up to ~210 barg in specialized steel grades, in practice, onshore pipelines are likely to top out around 100 barg.

When compressed hydrogen flows inside a pipeline, it experiences energy losses due to the fluid frictional losses with the pipeline's walls[2]. As gas is compressible, this friction causes a drop in pressure along the pipeline, that results in a reduction of the volumetric flow through the pipeline due to gas expansion. The frictional losses depend heavily on the fluid velocity in the pipeline, in the sense that if the fluid moves faster, the friction will be higher (thus higher pressure drop). If the fluid moves slower, there is less friction, but less hydrogen is transported per unit time.

Overall, designing a pipeline for a targeted transport capacity requires a balance between

- Larger diameters reduce fluid velocity and minimize friction and energy loss but are more expensive to build.
- Smaller diameters increase fluid velocity and friction, raising compression costs.

Usually, pipeline operators manage pressure drop by spacing compressor stations appropriately and when pipeline is properly sized. Thus, to reduce the problem of pressure drop it is important to consider the design-trade-off between capital cost (driven by pipeline diameter) and operating cost associated with energy consumption for compressors. Additional capital cost of installing more compressor stations must also be accounted for in this balance.

Figure 11 illustrates the pressure drop over distance for different pipeline sizes and an inlet pressure of 90 barg. Discrete increments in the nominal diameter, from 20 to 36 inches, translate into an exponential decrease in the pipe's pressure gradient.

[2] As a rule of thumb, an allowable pressure drop of 0.1bar/km may be used for initial size screening and high-level evaluation of booster compressor needs. The main equation used to evaluate pressure drops per unit of length in a pipeline is the Darcy-Weisbach equation: $\frac{dP}{dL} = f \cdot \frac{\rho \cdot v^2}{2 \cdot D}$, where dP/dL is the pressure drop per meter, f the friction factor (depends on Reynolds number and roughness), p the fluid density, v the fluid velocity and D the pipeline internal diameter.

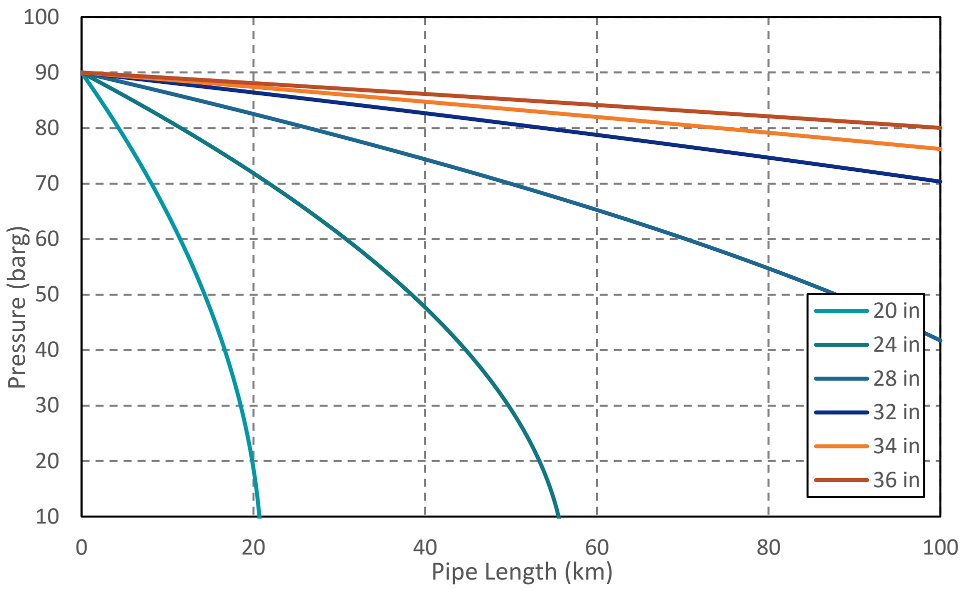

Figure 11. Pressure drop along the pipe length for 8 GW hydrogen for different pipeline diameters, starting pressure of 90 barg.

Line packing opportunity

If a pipeline operator wants to maintain system stability and support variable mismatch between hydrogen producers and consumers in the grid and accommodate green hydrogen production fluctuations, the pipeline itself could be used as a temporary storage medium, a method also known as line pack.

To do line packing it would be relevant to operate the pipeline under a higher pressure than normal even though it can increase pressure drop and reduce pipeline lifetime expectancy. Specifically, line pack refers to the available gas in the difference between the maximum and minimum pressure profiles within a pipeline. The "line pack" is identified as the buffer gas volume between the maximum pressure profiles defined by the maximum pressure condition and the minimum pressure condition when the pipeline operates at maximum flowrate [3].

Figure 12 illustrates the line packing potential. Larger pipeline dimensions and high design pressure give higher potential.

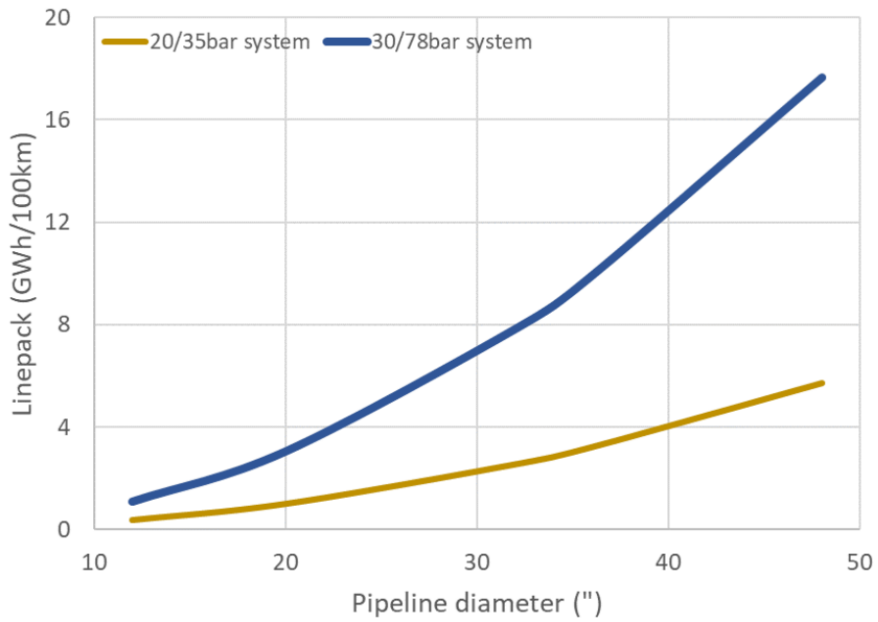

Figure 12. Illustration of line pack potential by Energinet for different pressures and pipe dimensions: possibility of storing gas between min. and max. pressure [4]. 3

However, hydrogen's low density influences pressure drops and line-pack characteristics. Thus, the potential energy stored via line-pack in a hydrogen pipeline is lower than in a natural gas pipeline of the same size.

This means a hydrogen network provides less intrinsic storage, potentially requiring additional storage facilities to balance supply and demand. Nonetheless, line-pack remains useful for short-term/storage from which hydrogen can be withdrawn to mitigate any imbalance that might occur on the hydrogen network. Operators can exploit the pipeline's pressure range to accommodate fluctuations in electrolyser output or hydrogen demand.

Choice of material

The transportation of hydrogen in gas form will weaken the pipeline and make the pipes brittle over time. Thus, the choice of pipe material is crucial to get the optimal lifetime and maintenance cost of the hydrogen pipeline.

Carbon steel is the primary material for hydrogen pipelines. Typically, API 5L line pipe material is used. However, the grade and treatment must be carefully selected. High-strength modern line pipe steels such as X70, X80 are more susceptible to hydrogen-induced cracking, hence hydrogen pipelines favour the use of lower-strength, tougher steels such as X52, X60 or X65, compensating

[3] E.g. if the grid is operated at approximately 35 barg in the initial phase, a 36" transmission pipelines will have a linepack storage of approx. 3 GWh/100km. If the pressure is raised to approx. 78 barg, there will be a linepack storage of approx. 10 GWh/100 km equivalent to 2.5 tonnes H2/km.

with thicker walls if needed. These lower-grade steels have higher tolerance to hydrogen and are proven in existing hydrogen pipelines.

In special cases stainless steel and composite pipes are also options, however this is mainly for transport of pure hydrogen in industrial sites or offshore.

Lining of pipeline

External coatings such as fusion-bonded epoxy or polyethylene (PE) wraps are also used on the outside of the pipe to prevent soil corrosion. This is a technology known from natural gas pipelines. Pipeline pipes and curved sections (hot bends) should generally be covered with a 5 mm layer of PE for protection, while pipes used in demanding conditions like Horizontal Directional Drilling (HDD) or tunnelling should have an additional 5 mm layer of glass-reinforced plastic (GRP) for extra protection due to the more challenging environment.

For example for the DHB, PE coating is expected to be used for most of the line sections in open land areas (90%), with the remaining using GRP coating due to proximity to higher risk areas or demanding conditions. GRP sections are expected to be more costly per km (considering fabrication, supply and installation) than PE sections.

Internal coatings for steel pipelines aim to reduce friction and improve the flow conditions. The efficiency gains have to be compared to the costs of applying internal coating. For example, hydrogen conversion projects in Germany and the Netherlands show, that internal coating is not required [5].

Cathodic protection

Cathodic protection (CP) is an effective method used to prevent corrosion on metal surfaces and prolong the technical life of the pipeline. For hydrogen pipelines cathodic protection is applied to the pipe to avoid corrosion by external environmental factors. The methodology is known from other types of pipelines, where impressed current cathodic protection (ICCP) or sacrificial anodes protection are used along the buried pipeline to prevent the steel from corroding in the soil.

An ICCP system uses devices called rectifiers and grounding beds to protect each section of the pipeline from corrosion and rust. This system keeps track of electrical currents (both AC and DC) and connects to the pipeline operators SCADA system for better control.

To protect the pipeline, it is divided into sections using special insulators. This helps control unwanted electricity and reduces the risk of electrical interference. Any pipeline parts connected to the power grid are isolated to avoid electrical problems. In risky areas, extra safety measures called EX spark gaps are added.

By-pass and reverse operation

Reverse operation of pipelines allows to change the flow direction and gives flexibility to adjust to supply and demand changes. Generally, pipelines can operate in both directions, with the limitation being junctions between systems with different pressure levels and station design. Hence, the design of the metering, compression and inlet/outlet systems decides, if the gas can be transported both ways.

A by-pass is a secondary flow path that allows the gas to circumvent a section of the pipeline and are relevant during repairs and maintenance. This is a standard design for the stations connected to pipelines.

Refurbishment of existing pipeline

Using existing pipelines is a way to establish pipeline infrastructure for hydrogen, while limiting the demand for buying and installing new material. This approach is planned to be used in other national hydrogen pipelines in Germany and The Netherlands, as well as some of the Danish Hydrogen Backbone. These projects are described later in the catalogue.

The most common existing pipelines are used for natural gas. These can only be used for hydrogen transport after undergoing testing and transformation according to specific rules and standards which can vary nationally. In Denmark, the standard from American Society of Mechanical Engineers is followed (ASME B31.12 [6]). The standards outline all the criteria that the pipeline has to fulfil, from material selection, design criteria, construction practices, testing requirements etc. The Standards are also used for new-builds and ensures that refurbished pipelines live up to the same criteria as new built.

Testing includes stress testing of existing natural gas pipes with hydrogen, to see how they react to the embrittlement that hydrogen imposes on certain metal types. Stress testing can include variation of pressure, bending the pipe to see the effect on permeation, and evaluating the integrity of welds and joints under various conditions to determine their resilience to hydrogen exposure.

Concretely there are certain parts of a natural gas pipeline that do not work with hydrogen. One example is the certain type of valve vent that works well in natural gas but has an explosion risk when the pipeline is operated with hydrogen. This is due to the different molecular structures of hydrogen.

In general, refurbishing a pipeline is less costly than establishing a new one. Repurposing existing gas pipes to hydrogen is around 75% cheaper than newbuilt pipelines according to cost estimates by the European Hydrogen Backbone [7]. However, the refurbished pipeline might have limitations on pressure, volume and capacity that would not be a constraint when designing a new built. Hence, a trade-off between cost and purpose exists when deciding whether to refurbish.

Stations

A hydrogen infrastructure system includes various stations along the route of pipeline for control, maintenance, and pressure management. The main ones, further described in the following, are Line Valve/vent stations, Pig Launcher and Receiver (PLR) stations (to handle pipeline inspection, cleaning or maintenance), metering stations, injection stations, extraction stations and mainline booster stations, with each serving a specific function and placed at strategic intervals. Stations are located at the inlet, outlet and along a pipeline and can contain one or several components. This means, that many of the stations listed below can be combined at one station site.

In general compressors stations, fiscal metering stations and PLR stations are needed at the inlet and outlet of the pipeline. Booster stations are only required along the pipeline in segments where the pressure drops below the minimum design limits. LV stations are typically placed every 15-30 km. In this catalogue they have been assumed to be placed every 20 km.

Compressors are vital for pressurizing hydrogen in the pipeline and compensating for pressure drop over distance. Hydrogen compression is challenging due to the small molecular size and high diffusivity of H_2, but proven technologies from the gas industry are applicable with modifications. The two main compressor types for pipeline service are centrifugal compressors and reciprocating compressors.

- Centrifugal Compressors: these are turbo-compressors and are the workhorse of natural gas pipelines for high-flow applications. They are also favoured for large hydrogen pipelines because of their ability to handle high throughput continuously. However, because hydrogen's molecular weight is much lower than natural gas a centrifugal compressor must spin about three times faster to achieve the same pressure ratio for hydrogen. This is due to hydrogen's higher sound speed and lower density. Engineering solutions include specialized impeller designs, high-speed electric motors or gas turbines, and often multi-stage compression with inter-cooling to reach the desired pressure. Companies like Siemens Energy and Baker Hughes are adapting pipeline compressors for 100% hydrogen, for example, by using materials that resist hydrogen embrittlement in impellers and ensuring seals minimize leakage. Centrifugal units are ideal for mainline compressor stations where flow rates are huge and pressure boosts per stage are moderate.

Figure 13: Example of next-generation centrifugal compressor from Siemens Energy [8].

- Reciprocating Compressors: these use pistons (or diaphragms) in cylinders to compress gas and can achieve very high pressures in multiple stages. They are typically used for smaller volumes or higher differential pressure needs, such as filling hydrogen storage or in refuelling stations. In pipeline service, reciprocating compressors could be used in situations that require high compression ratios or flexible operation (they can be turned down to lower flow more easily than centrifugals). Modern API 618 reciprocating compressors are available for hydrogen duties up to pipeline scale, but they have more moving parts and usually lower flow capacity per unit than centrifugal machines. They might be chosen for initial smaller pipelines or for booster stations feeding into the main network, for example, compressing hydrogen from an electrolyser plant into the grid. An example of a reciprocating compressor is shown in Figure 6.

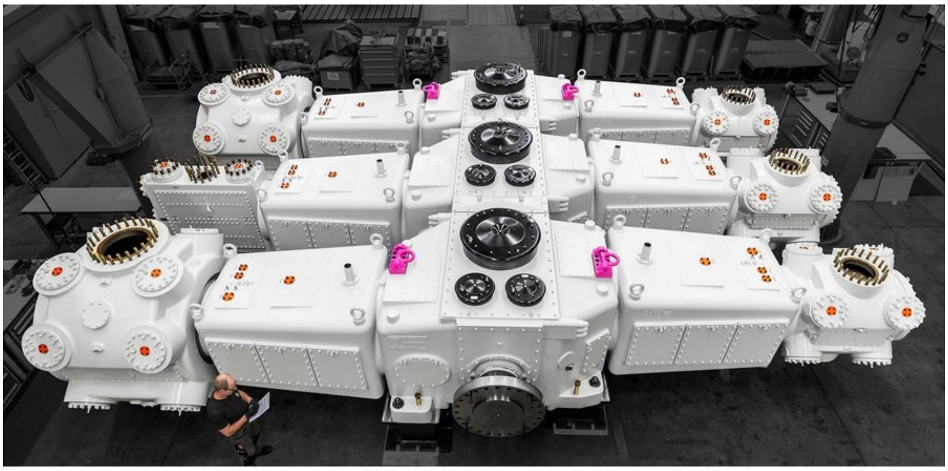

Figure 14: Reciprocating compressors with inlet pressure of 10-40 barg, outlet pressure of 60-100 barg, and 2 to 3 stages [6].

Booster stations: in long pipelines it can be necessary to boost pressure to overcome pressure drops, keep pressure above the minimum operating levels and ensure a steady flow in the pipeline. This is done in facilities along the pipeline that house compressors to boost the pressure. The exact distance between booster stations depends on pipeline diameter, volumetric flow rate, and the initial inlet pressure. For example, each station typically consists of multiple compressor units for redundancy and capacity scaling, aftercoolers to remove heat of compression, scrubbers/filters to ensure gas purity and remove any oil or dust, and control systems. They often also have an adjacent pigging launcher/receiver and mainline valves to isolate the station. Booster stations can also contain some noise and vibration control systems.

Line Valve (LV) Stations: these are isolation or block valves on the pipeline that can shut off flow in an emergency or for maintenance. A valve station typically consists of an automated large-diameter valve (often remotely actuated), a bypass line, and vent/blowdown facilities to depressurize a section if needed. Hydrogen line valves are usually placed at similar intervals as in natural gas service – roughly every 10–30 km depending on terrain and risk zoning. Closer spacing is used near populated or sensitive areas (to limit the inventory released in a leak), whereas in sparse rural stretches the distance between valves can be larger (e.g. 20+ km). These stations are small, fenced sites, usually unmanned, with pipeline markers and telemetry. The safety corridors ensure that if a segment is isolated and vented, the hydrogen discharge (typically via a tall vent stack) won't endanger the public. Valve stations are a fundamental safety feature, allowing operators to quickly sectionalize the pipeline in case of a leak detection.

Pigging launch/receiver (PLR) Stations: pigs are inspection or cleaning devices that travel inside the pipeline. PLR-stations are installed at pipeline endpoints and key nodes to insert pigs and to retrieve them after they traverse a pipeline section. A PLR-station includes a pipe connection with a launcher barrel, closure doors, and associated valves. Given the embrittlement concerns from hydrogen, monitoring of the pipeline through frequent inspections with pigs is crucial to detect corrosion levels, detect cracks, and clean any deposits. Intelligent pigs (inspection tools) can check for hydrogen-induced cracking as part of integrity management. Typically, a long pipeline will have a pig launcher at one end, or at a compressor station, and a pig receiver at the other end. If the pipeline is very long or has branches, multiple pigging sections can be defined. Pigs usually cannot pass through a running compressor, hence either separate pigging per segment is needed. Segments could be defined between mainline compressor stations. Pigs are used during normal operation and the pipeline is not emptied of hydrogen.

Figure 15: Example of Pigs used to clean and inspect a pipeline [9].

Injection & extraction station: manage the controlled entry and withdrawal of hydrogen into and from the pipeline network with third party interface points. Injection stations enable hydrogen from production sites, storage facilities, or import terminals to be introduced into the pipeline, ensuring correct pressure, flow rate, and gas purity using compressors, flow control valves, filtration units, and metering systems. Extraction stations, conversely, allow hydrogen to be safely drawn off for delivery to industrial users, distribution networks, or storage, with pressure regulation, flow control, and fiscal metering equipment ensuring the supply meets user specifications.

Mainline pressure regulation station: mainline pressure regulation stations (MPR) manage and stabilize the pressure within the hydrogen pipeline to ensure safe and consistent downstream flow. They typically consist of pressure regulators, control valves, pressure relief systems, and instrumentation to monitor pressure levels. MPR stations are critical where pressure must be reduced to match the limits of downstream infrastructure, especially at interconnections — such as between a newly built pipeline and a re-purposed pipeline with different design conditions — at distribution points, or before entering populated areas.

Fiscal metering station: metering stations measure the quantity and quality of hydrogen transferred between different owners, operators, or network sections for billing and regulatory purposes. They typically include high-accuracy flow meters, pressure and temperature sensors, gas analysers, and data recording systems. The hydrogen's flow rate, energy content, and composition are monitored to ensure compliance with commercial and contractual requirements. Fiscal metering stations are crucial for commercial transactions and are usually located at pipeline endpoints, major interconnections, or entry/exit points to industrial clusters.

Space requirement

Hydrogen has a wide flammable range, hence for safety reasons hydrogen pipelines require safety corridors (rights-of-way) where construction and habitation are restricted. In Denmark and most of Europe a buried pipeline's route is kept clear of buildings. Similarly deep excavation activities are restricted within a certain distance, typically 5 to 10 meters on each side. This is subject to varying national codes and pipeline pressure.

The "safety belts" ensure that in the unlikely event of a leak or rupture, the immediate area is clear of people, and they provide access for maintenance. Typical national guidelines use risk assessment to determine separation distances. For example, stations or valves might have a fenced perimeter and a minimum distance (e.g. 4 m or more) to any other equipment. In Denmark authorities will designate pipeline corridors and consult local communities to maintain safety corridors around the new hydrogen pipelines. This is analogous to the safety zoning around other gas pipelines such as natural gas. Whereas safety corridors for natural gas transmission pipelines in Denmark can be around 20 meters on each side, a wider corridor about 40 meters can be expected for some hydrogen pipelines.

The required amount of space occupied by the pipeline project will depend on the selected design factor, which is determined by the pipeline routing, sensitive elements around the corridor and the applicable standards.

Design considerations in relation to other infrastructure and buildings

Hydrogen pipelines must be engineered with regard to nearby infrastructure and environmental constraints. Pipelines are typically buried underground (minimum 1.2 m cover is required according to standard for hydrogen pipelines) to protect from external damage. When crossing roads, railways, or waterways, the pipeline may be encased in a secondary sleeve or installed via horizontal directional drilling to minimize risk and disturbance.

The pipeline design accounts for electrical infrastructure as well. For instance, mitigating stray currents from high-voltage lines or rail that could affect cathodic protection and cause increased corrosion.

Buildings and pipelines must maintain safe separation; national standards (like Denmark's DS/EN codes or European directives) specify minimum distances from houses, hospitals, etc., based on quantitative risk analysis. In industrial areas where hydrogen pipelines run alongside other utilities (power cables, fibre optics, etc.), coordination in design is needed to ensure no interference (for example, special grounding if a pipeline runs near high-voltage cables).

Another consideration is emergency access: routes are chosen such that emergency crews can reach any point, and vent stations (for depressurizing the line) are located away from busy areas to allow safe release of hydrogen gas if maintenance requires emptying a segment. All these factors mean hydrogen pipeline routing and design undergo extensive planning and permitting. In Denmark's upcoming projects, environmental impact assessments and spatial planning are being conducted to align the hydrogen corridors with existing infrastructure corridors where feasible, while maintaining the required safety distances.

Class location determination principles

Class location is a way of categorizing risk along the pipeline route. Low population equals low risk and low location class (min. 1). High population equals high risk and high location class (max. 4). Higher location classes require a larger safety margin in the design (design factors). The design factor for steel pipelines refers to a safety factor used in pipeline design to ensure the pipeline operates safely under pressure and other conditions. It is a ratio that reduces the allowable stress in the pipe material to ensure the pipe can handle the expected pressures and loads safely. Location classes are determined according to ASME B31.12 [6] sections PL-3.2.1 and PL-3.2.2 and the following Design Factors for location class 1 to 4 are defined in Table 16.

Table 16: Design factors for steel pipelines for location classes 1 to 4 [6].

Table PL-3.7.1-7
Design Factors for Steel Pipe Construction (Used With Option B)

Facility	Design Factor by Location Class			
	1, Div. 2	2	3	4
Pipelines, mains, and service lines	0.72	0.60	0.50	0.40
Crossings of roads, railroads without casing:				
(a) Private roads	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.60	0.60	0.50	0.40
(c) Roads, highways, or public streets with hard surfaces, and railroads	0.60	0.50	0.50	0.40
Crossings of roads, railroads with casing:				
(a) Private roads	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets with hard surfaces, and railroads	0.72	0.60	0.50	0.40
Parallel encroachment of pipelines and mains on roads and railroads:				
(a) Private roads	0.72	0.60	0.50	0.40
(b) Unimproved public roads	0.72	0.60	0.50	0.40
(c) Roads, highways, or public streets with hard surfaces, and railroads	0.60	0.60	0.50	0.40
Fabricated assemblies	0.60	0.60	0.50	0.40
Pipelines on bridges	0.60	0.60	0.50	0.40
Pressure/flow control and metering facilities	0.60	0.60	0.50	0.40
Compressor station piping	0.50	0.50	0.50	0.40
Near concentration of people in Location Classes 1 and 2 (see para. PL-3.3.2)	0.50	0.50	0.50	0.40

Advantages/disadvantages

There are both advantages and disadvantages to the transport of hydrogen in pipelines.

The main advantages with pipeline transport are:

- Large volumes can be transported at low operating costs, with low energy consumption
- No occupation of existing infrastructure (roads, harbours, etc.)
- Continuous operation independent of weather conditions and other external disruptions.
- Long technical lifetime and possibility of buffer storage with line packing.

The main disadvantages with pipeline transport are:

- High initial investment costs,
- Long planning and construction time including extensive approval procedures i.e. construction within city limits is difficult, land purchase issues, public perception
- Low flexibility (end-use value) if the hydrogen producer ceases production or relocates.

However, the alternatives to moving large volumes of hydrogen are very limited (see road transport chapter), hence pipeline transport remains the most obvious way to connect producers and off-takers in the hydrogen market.

Environment

The environmental impact from the hydrogen pipeline is expected to be quite different in the construction phase compared to daily operations. The construction phase can have substantial environmental impact depending on the chosen route of the pipeline. An environmental impact assessment (EIA) will be required for the entire project, and it is unlikely that routing is allowed to run through vulnerable natural areas without significant measures to minimize environmental impact. It is likely that routing will take this into consideration and mainly bypass vulnerable nature.

Once the pipeline is constructed it will only have a minuscule environmental impact. Hydrogen leakage from a hydrogen pipeline will not occur during ordinary operations. Emission of hydrogen might happen in the event of maintenance and repair work, where a blow down of pipeline sections is likely needed. However, as long as this happens in a slow and controlled process, where most of the gas is evacuated to other segments of the pipeline, it will not have a significant environmental impact.

Research and development perspectives

Pipelines are considered an "old technology", hence no further technological development are expected to make it significantly cheaper nor more expensive over the coming years. Even though hydrogen pipelines are a relatively new field, the technology is expected to build on traditional onshore pipeline principles.

Examples of market standard technology

Several hydrogen pipeline projects are currently being developed across Europe by various TSOs to establish the future hydrogen infrastructure. A selection of these projects is presented below as reference cases to illustrate typical design characteristics.

Danish Hydrogen Backbone

In Denmark, a hydrogen pipeline is planned to run from north to south on the peninsula of Jutland. The pipeline will connect producers on the west coast of Denmark with industrial consumers in Germany south of Denmark. The potential routing is shown in Figure 16. The planned total length is 375 km, and the planned pipe dimension is 36-inch diameter. Most of the pipeline will be newly built, except for the final 88 km near the German border, which is planned to be a refurbished existing natural gas line. The design pressure is 100 barg, and the Danish TSO, Energinet, expects to operate the pipeline within a range of 60 to 90 barg. The expected maximum designed energy transport capacity is 8 GW.

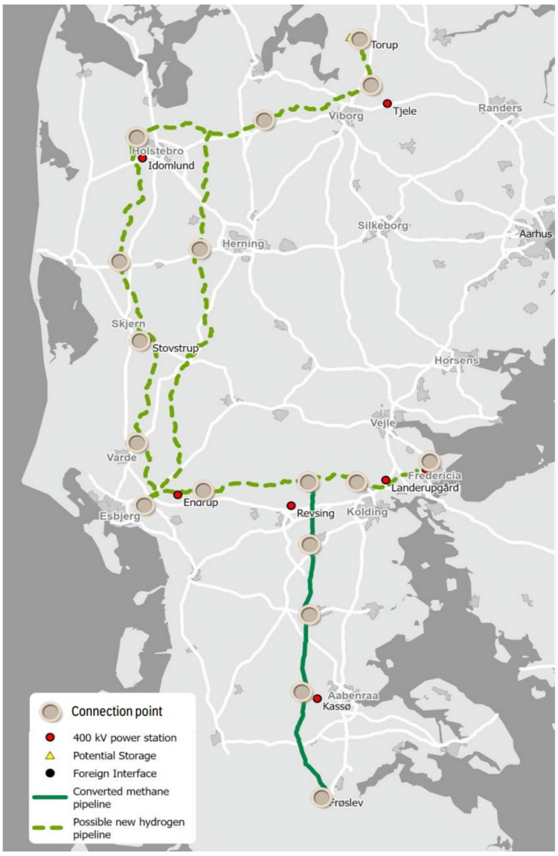

Figure 16: Potential routing of Danish Hydrogen Backbone and locations for the connection points [10].

Dutch Hydrogen Network

In the Netherlands, a national hydrogen backbone is under development, connecting key industrial hubs across the country based on project information from Gasunie. The planned network will span approximately 1,200 km, with pipeline diameters averaging 36 inches. About 80% of the infrastructure will be refurbished from the existing natural gas grid, while the remaining 20% will consist of newly constructed segments. The design pressure is expected to be 66.2 barg, with the operational pressure stated to be between 30 and 50 barg [11].

German Core Network

In Germany, a national hydrogen core network is being developed as illustrated in Figure 17. The approved network will extend over 9,040 km, with pipeline diameters varying by route, typically ranging from 28 to 56 inches. Approximately 60% of the infrastructure will be refurbished from existing natural gas pipelines, while the remaining 40% will involve new construction [12]. Operating pressures are expected to range between 70 and 100 barg, depending on the segment [13].

Figure 17: Approved hydrogen core network in Germany [12].

Quantitative description

Investment costs (CAPEX)

The CAPEX includes equipment and installation costs, which cover materials, labour and equipment:

- Equipment covers pipeline and stations fabrication and supply
- Installation also includes trenching, engineering, testing and commissioning

The overall investment costs for several pipeline dimensions and pressure levels is further reported in the datasheet. The estimates are based on COWI in house experience from project work on several pipeline projects in Denmark. The estimates are benchmarked with publicly available data from Germany [13], where the costs are slightly higher. This is most likely due to those costs including other overhead costs on top of the installation.

The following assumptions are considered when estimating CAPEX for several pipelines' dimensions and pressures:

- A design factor of 0.6 is assumed based primarily on rural routing.

- Pipeline is assumed to be PE coated and made of carbon steel. Safer protection using GRP coating will increase the pipeline CAPEX per km, however it is expected that such material would be used only for minor segments of a pipeline project.
- Pipeline is assumed to follow a straight routing with no hot bends included. Each hot bend would come at an additional cost per unit, increasing overall CAPEX[4].
- The hydrogen is injected into the pipeline at the corresponding pressure. Energy use for that compression is not included.
- PLR stations and LV stations are included in the CAPEX while compressors/booster stations are not. These are provided as separate figures to be added on top of the pipeline investments depending on the specific project requirements for compression and boosting.
- Cathodic protection (corrosions protection), site works and crossings are included in the datasheet figures.
- Owner’s costs, land costs, contingencies, escalation and abandonment expenditure (ABEX) costs are not included.
- CAPEX for all years represents a 2025 cost level (does not include inflation) and does not include owner contingency, according to the guidelines of the catalogue.

Pipeline Cost Methodology

The total investment costs are provided for defined pipeline diameters and fixed operating pressures, with the total capacity of the pipeline being determined by the pipeline operating conditions and design. Total investment costs for actual 36´´ transmission pipeline projects and actual 12´´ and 8´´ pipeline projects are known to the authors. Therefore, to estimate the CAPEX for the pipeline dimensions listed in Table 15 across various pressure ranges, an engineering-based methodology has been applied and calibrated against actual project estimates.

The first step of the approach is to determine the required wall thickness for each pipeline diameter, based on the internal design pressure the pipeline must safely withstand. According to the engineering guidelines [14] used across several hydrogen pipeline projects, a minimum wall thickness of 5 mm is applied for all hydrogen pipelines, even in cases where lower pressures and smaller diameters (e.g., 8" or 12") would theoretically allow less wall-thickness, thus less material. Walls thinner than 5 mm are more susceptible to breaking while handling the pipes under transport and installation.

In general, project developers tend to procure standard pipeline sizes that are commercially available and mass-produced by manufacturers, commonly referred to as “off-the-shelf” solutions for their large-scale applications. To buy “off-the-shelf” solutions are often cheaper due to the manufacturers ability to exploit economies of scale in mass-production, hence lowering production costs. Conversely, for larger pipeline sizes of 20", 30”, and 36", even a few millimetres of variation in wall thickness can have a significant impact on total CAPEX due to the substantial material volume involved. Therefore, in large-scale projects, it is often economically beneficial to tailor pipeline dimensions to project-specific conditions, optimizing thickness to meet design and safety requirements.

[4] Hot bends are accounted for in pipeline projects by applying an additional unit cost per bend. While the exact cost depends on the bending angle, it is generally estimated to range between EUR 15,000 and 18,000 per hot bend, covering fabrication, supply, and installation.

When the appropriate wall thickness is established based on technical factors such as design pressure, design factor, and the tensile strength of the chosen material, the mass of carbon steel required per meter of pipeline is calculated. This mass is then multiplied by a unit cost (EUR/kg), which includes material fabrication, pipeline supply, and on-site installation (i.e. much more than just a steel price). For the CAPEX values presented in the datasheet, a unit cost of 6 EUR/kg has been applied, as this figure is broadly representative of costs observed across multiple benchmarked projects.

Trenching costs are estimated separately by calculating the volume of soil displaced[5] per meter of pipeline (m^3/m) and applying a unit cost per cubic meter, based on COWI project estimates. The estimate used is 240 EUR/m^3 and includes the scope of trenching activities, excavation, minimum mechanical dewatering, backfill, and excess disposal.

It is also important to note that each pipeline diameter has a maximum transport capacity, which depends on operating pressure and the design velocity of hydrogen flow. Ultimately, the levelized cost of hydrogen transport will depend heavily on pipeline utilization rates and the ability to leverage line-packing capacity.

PLR and LV Stations

Based on COWI experience on a 36” pipeline dimension, the cost of a PLR station can range between 2.9 and 6.2 MEUR and the cost for a LV station between 3.4 and 7.4 MEUR. It is expected that the unit cost per station can be scaled linearly with the pipeline dimension[6].

The investment costs for PLR and LV stations have been incorporated into the pipeline CAPEX values presented in the datasheet. These estimates assume a pipeline length of 100 km, with PLR stations installed at both the inlet and outlet, and LV stations positioned every 20 km, including at both ends of the pipeline.

In general, the investment cost share of the stations increases as the pipeline length decreases.

Compressors

Compressors and boosters along the pipeline, are not included in the pipeline CAPEX but are reported separately, as these costs are highly project specific. Including a compressor station can be relevant, if pressure has to be increased after electrolysis before injection into the pipeline or at injection stations between two pipeline systems with different operating pressure levels. The CAPEX of the compressors for hydrogen pipelines is expected to be between 0.8 and 2.4 MEUR/MWe for a compressor with inlet pressure between 10-40 barg and outlet pressure between 60-100 barg.

Additional project costs

Besides the pipeline investment costs there are several indirect cost components that should be considered when planning a project. These costs can be considered as a percentage of the total investment costs and are added on top of the CAPEX to estimate the total costs for a project. The additional costs cover the owner’s costs for administration, consultants, project management, site preparation, approvals by authorities as well as land costs, which are considerable for

[5] Assumed to be on average 2 m depth and 2 m width by default and accounting for varying pipeline diameters.

[6] Scaling based on a 36” pipeline, where (n) is the pipeline dimension in inches: $Unit\ cost\ station\ scaled = \frac{n}{36} * unit\ cost\ 36"\ station$

pipelines. The additional project cost shares are reported as reference estimates in Figure 10 based on COWI experience.

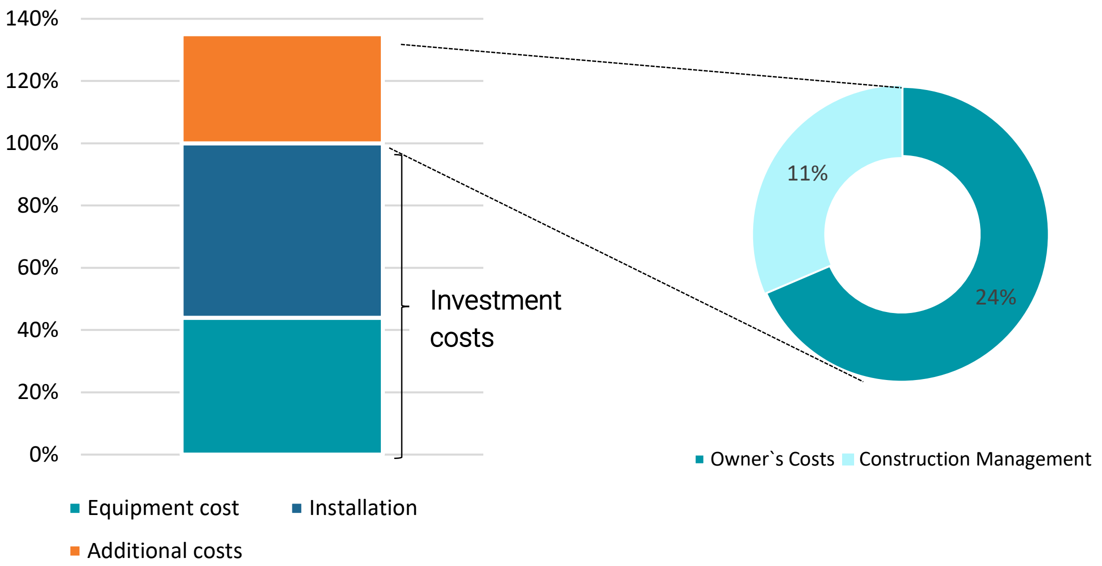

Figure 18. Typical distribution of key additional project costs components for hydrogen pipeline as share of total investment costs (note that total % sum is more than 100, as the additional costs should be added on top to estimate total cost for a pipeline project)

These additional costs encompass various aspects of a pipeline project.

- Construction management oversees scheduling, quality control, and contractor coordination to ensure timely and budget-compliant completion.
- Owner's Costs capture project owner-related expenses, such as project management, legal fees, permitting and administration.

Operational Expenditures (OPEX)

Fixed OPEX: are strictly dependent on the operational and maintenance philosophy of the pipeline owner and operator. In pipeline infrastructure projects for hydrogen transport, OPEX is usually estimated as a fixed percentage % of CAPEX derived from the cost estimate for reference projects.

Fixed operational cost is expressed in €/km per year and includes ordinary pipeline inspection and maintenance, internal continuous monitoring for pressure, corrosion and leakages, and purchase of maintenance material. The fixed OPEX is estimated to be approximately 1% of the total CAPEX for the pipeline per year, including the maintenance of the stations.

Variable OPEX: these are primarily relevant if compressors are used to maintain a pressure level above the minimal operational needs. The values can be determined by the *Energy to compensate pressure drop*, which is stated in the data sheet. In case compressors are used at inlets or outlets of the pipeline, there can be energy usage needed to adjust the pressure differences. In the data sheets, the energy usage is stated for going from 40 to 90 barg and going from 40 to 140 barg, which can be relevant scenarios of compressing hydrogen after electrolyses at the pipeline inlet. The actual pressure difference and hence compression needs depend on project specific factors and will vary.

Price projection

Due to pipelines being old technology, future costs of establishing hydrogen pipelines are likely to follow general inflation unless severe external shocks hit steel prices.

Advances in research on the lining of the pipeline may extend the lifetime of the pipeline as well as contribute to lower operating costs. This remains highly uncertain and the potential impact on operating costs will only be minor.

Uncertainty

While no large hydrogen pipelines are currently in operation in Denmark, plans are in place to establish a national hydrogen backbone, with cross-border infrastructure between Denmark and Germany targeted for commissioning around 2030. Until such infrastructure is realized, there remains some uncertainty around performance, permitting procedures, safety requirements, and cost.

The best-known cost estimates from the most developed projects are on AACE class 3 level, implying an uncertainty level of -20% to +40%. However, the cost estimates in this catalogue are general in nature and do not account for project specific circumstances, hence they should be considered AACE class 5 level, implying an uncertainty of -30 %/+50 %.

Additional remarks

The reference list can be found at the end of the next chapter.

5 Transport of hydrogen by road

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Qualitative description

Brief technology description

Road transport of hydrogen is only a viable option for moving small quantities over short distances. Under these conditions, road transport offers flexibility, the ability to off-take and deliver at any location, and lower upfront investment costs compared to pipeline transport.

There are generally two ways of transporting hydrogen by truck:

- In cryogenic liquid form (LH_2) in tank trailers or containerized tanks.
- In compressed gas form (CH_2) in high pressure cylinders and tube trailers or containerized tanks.

The choice between liquid and gaseous form involves trade-offs in storage capacity, weight, and complexity. Generally, liquid hydrogen offers a higher payload per trip, however the process of keeping it cryogenic makes it more complex. Technical equipment for transport in gaseous form is simpler as no cryogenics are required, however, it still requires heavy high-pressure vessels.

Hydrogen road transport requires specialized loading and unloading equipment to transfer hydrogen between trucks and storage at production or use sites. These transloading stations must handle either high-pressure gas or cryogenic liquid safely and efficiently.

Description of options for road transport

Tank truck (LH_2)

Tankers for liquid hydrogen can carry cryogenic LH_2 at –253 °C in insulated vacuum-jacketed tanks. Compared to CH_2 transport, more H_2 can be carried for the same volume, as the density of liquid hydrogen (~70 kg/m³ at cryogenic temperature) is higher than that of gaseous hydrogen (~0.089 kg/m³ at 1 bar, ~15.6kg/m³ at 200 bar and ~33kg/m³ at 500 bar) [15].

A typical semi-trailer has a 40–50 m³ insulated vessel made of austenitic stainless steel to withstand extreme cold without embrittlement. Design pressure for LH_2 trailers is modest, typically around 6 to 10 barg.

Thanks to higher H_2 density when liquid, a single tanker can carry 2,500–3,500 kg of hydrogen. In practice, payloads are often limited by road weight regulations. Adding the 3.5 tonnes of hydrogen to a road train with high pressure tank, bring it near the upper limit of 44 t gross vehicle weight for a vehicle with 5 axles as seen in Figure 19.

Boil-off evaporation of H_2 due to heat transfer from the environment is a key issue. For this reason, modern tanks have multilayer insulation giving boil-off rates of <0.5–1% per day. Over typical delivery times (hours to a couple of days), boil-off losses are small, but insulation is critical if tanks store for longer.

Figure 19: A cryogenic liquid hydrogen trailer. Vacuum-insulated LH_2 trailers can haul roughly 3 tonnes of H_2 at ~6–10 barg and –253 °C [16].

Tank truck (CH_2)

Compressed hydrogen tank trucks (tube trailers) carry hydrogen in multiple high-pressure cylinders or tubes mounted on a trailer frame. Older designs used many steel cylinders designed for 200 barg, resulting in heavy trailers carrying only between 160–340 kg of hydrogen (Figure 12 left). Modern designs use fewer but larger composite cylinders (Type III/IV) that allow for a higher pressure around 250–500 barg (Figure 12 right). These advanced tube trailers can achieve payloads between 850 and 1,000 kg of hydrogen [17].

Further gains are being pursued: for example, a 40 ft Type IV trailer at 500 barg can hold over 1,000 kg H_2, and prototypes at 700 barg could carry ~1.5 tonnes. Higher pressure increases capacity but also requires more expensive materials and certification (ADR 6.2 tests for burst, fire, etc.). The tare weight of these trailers is high – a 1,300 kg H_2 composite trailer may weigh ~20–25 tonnes empty – so hydrogen is only ~5–10% of the gross weight.

Figure 20: Multiple high-pressure cylinders in an old design (left) and fewer more compact newer design (right) [16].

Containerized tanks

Hydrogen can also be transported in containerized tanks that are not permanently attached to a truck. Containerized tanks allow multimodal transport (road, rail, ship) and on-site storage. A container can be left at a customer site as a temporary storage unit and replaced when empty. The trade-off is some added weight and slightly lower capacity compared to a dedicated trailer due to the frame. These ISO containers conform to standard intermodal container dimensions and fittings, either 20 ft or 40 ft.

Containerized tanks (CH_2)

For compressed hydrogen, a container typically bundles many cylinders or tubes in a frame. The internal storage is analogous to a tube trailer (Type I steel or Type IV composite cylinders at 200–300+ barg). A 40 ft gaseous hydrogen ISO container can hold around 340 kg of hydrogen at 200 barg when made of steel cylinders. If made of composite materials it can hold around 850 kg at 300 barg. If using advanced 700 barg vessels, capacity can go up to 1,600 kg. These containers can be loaded on standard trucks or rail wagons, offering flexibility to swap at sites without dedicated trailers.

Containerized tanks (LH_2)

Liquid hydrogen ISO containers are also used; a 40 ft LN_2/LH_2 ISO tank might carry ~2,700 kg of LH_2. They have similar construction to fixed LH_2 trailers, with a vacuum-jacketed inner tank in a frame, and must meet ISO tank container standards for pressure, lifting, and transport stress.

Figure 21: ISO container for LH_2 transport (left) [16] and CH_2 transport (right) [17].

Design pressure for hydrogen tanks for trucks

Design pressure is a critical parameter for hydrogen transport tanks, affecting safety, capacity, and regulatory compliance. Road hydrogen vessels in Europe must meet ADR standards for dangerous goods, which define testing and certification for different pressure classes.

Compressed H_2 trailers: common working pressures are 200–250 barg for older steel tube trailers and 300–500 barg for modern composite trailers. The design pressure is slightly higher (to include safety margins). For example, a 500-barg trailer might have cylinders certified to 525 or 550 barg. Advanced composite multi-element gas containers (MEGCs) are being developed for 700 barg service, but widespread use at this extreme pressure will depend on further standardization and cost trade-offs. Higher pressure increases the amount of hydrogen that can be carried (per the gas law) but also requires thicker or stronger cylinder materials (often carbon-fibre overwrap) and more stringent testing. To compress hydrogen to high pressure, loading stations and compressors are needed, as further described below.

Liquid hydrogen trailers: these are low-pressure tanks; typical design pressure is 6–10 bar. The tank normally operates near atmospheric pressure which is just enough to push liquid out. However, it must accommodate pressure rise due to boil-off when idle. Relief valves usually open around the design pressure to vent excess gas and keep the tank below its limit. The pressure rating also dictates refilling and offloading conditions, e.g. an LH_2 trailer may be pressure-built to 5–8 bar to transfer liquid, then it will drop back down.

Input

The input for hydrogen transportation encompasses three key components: 1) fuel to be transported, LH_2 or CH_2; 2) fuel for propulsion, that is consumed for the transportation; 3) fuel for maintaining the required temperature of the liquefied hydrogen during transport, although normally this is not the case and some boil-off is accepted.

For CH_2 tube trailers, loading typically requires a high-pressure compressor system if the sourced hydrogen is at lower pressure. The trailer may be filled from buffer storage via a cascade fill process by connecting the trailer to storage banks of progressively higher pressure to equalize stepwise.

Final top-up compression may be needed to reach the trailer's target pressure. Temperature rises during fast filling is a concern (Joule-Thomson heating), so fill rates are moderated. A full load of 500–1000 kg might take 2–3 hours. Monitoring is critical so pressure, temperature, and hydrogen flow are measured to avoid overfill.

For LH_2 tankers, loading is done at a liquefaction plant or LH_2 depot using cryogenic transfer equipment. A cryogenic pump or pressure transfer system is used. The trailer is connected via an insulated transfer hose, and LH_2 is pumped in or the trailer is chilled and filled by gravity/pressure difference. Loading a full 3,000 kg LH_2 trailer might be faster than gas because pumping liquid is quicker, but in practice still takes 1–2 hours including cooldown.

Table 17: Differences in handling compressed and liquified hydrogen.

Parameter	Compressed hydrogen (CH_2)	Liquified hydrogen (LH_2)
Typical payload (t)	1.2-1.5	2.5-3.5
Operating pressure (bar)	350-500	6-10
Operating temperature (°C)	Ambient	-253
Loading duration (hours)	2-3	1-2

Output

The output for hydrogen transportation is the hydrogen that has been transported, which normally is the same as the input, assuming there will be no leakage, with the only exception being boil-off for LH_2.

For CH_2 trailers, unloading usually relies on pressure differential. The trailer arrives with tanks at e.g. 200–500 bar, and the site storage (or process) might be at lower pressure (e.g. 80-100 bar). By connecting the trailer and opening the valves, hydrogen flows out until pressures equalize. To improve efficiency, operators may use a booster compressor on site to pull more gas out of the trailer once the pressure equalizes. Without a compressor, a significant residual pressure (and thus hydrogen) can remain in the trailer (often 10–20% of load) that cannot be delivered. Modern practice tries to minimize "return gas" by pushing as much hydrogen as possible, either by active compression or by cooling the trailer. Any remaining gas is later vented down to safe pressure after the trailer is disconnected before it travels back empty.

For LH_2, unloading is typically achieved by pressure build-up or using an onboard cryogenic pump. In pressure-build transfers, a small amount of LH_2 is evaporated in a heater to increase the tanker pressure to 5–8 bar, which then pushes the liquid out through the transfer line. The customer's storage tank is at lower pressure (usually near ambient pressure), so the liquid flows in. This method requires careful control to avoid over-pressurizing. Alternatively, some LH_2 trailers or delivery sites use cryogenic pumps to actively transfer liquid, which can achieve higher flow rates and even pump into pressurized tanks. During unloading, boiling off gas from the receiving tank or trailer may be managed via a return line, e.g. the vapor displaced from the customer tank can be routed back into the trailer or to a flare/vent system.

Energy balance

Efficiency and losses for hydrogen transport by truck include: 1) losses when hydrogen is converted to liquid phase when cooled, 2) compression losses for CH_2, 3) pumping losses for LH_2, 4) losses due to cryogenic LH_2 interaction with surrounding warmer air (boil-off). Hydrogen leakages are assumed to be negligeable.

Safety in the transport of hydrogen by road and during transloading

Safety is paramount in road transport of hydrogen due to its flammability, high pressure, and extreme cold (for liquid). Regulations in Europe (Agreement concerning the International Carriage of Dangerous Goods by Road -ADR) classify hydrogen (UN 1049 for compressed, UN 1966 for liquid) as a hazardous material and impose strict requirements on tank design, operations, and driver training [16].

Vehicle and tank safety: hydrogen trailers are built with multiple safety relief devices. Compressed gas cylinders have pressure relief valves/fuse plugs that vent gas if internal pressure or temperature exceeds limits for example in a fire. Liquid tanks have dual relief valves for redundancy, typically set just under the design pressure, to periodically vent boil-off and prevent overpressure. Tanks undergo periodic inspection and hydrostatic testing as per ADR (often every 5 years for pressure vessels). The transport units are labelled with hydrogen hazard placards, and sensors (thermal, hydrogen detectors) may be installed to alert the driver of any leaks [16].

Operational safety measures: routing and parking are planned to reduce risk. Usually, carriers avoid densely populated areas when possible and may have designated routes approved for hazardous goods. Drivers must have ADR Hazardous Materials training and follow procedures like periodic leak checks during transit. Vehicles carry emergency equipment (fire extinguishers, protective gear) and documentation detailing the cargo. When parking or in an emergency, the driver is instructed to keep the vehicle in a ventilated area away from ignition sources and not to leave it unattended for long near public areas. In case of an accident or breakdown, no repair involving the hydrogen system can be done with product in the tank. The area must be secured, and expert responders handle the situation, often letting hydrogen vent or burn off safely if a leak is present [16].

Transloading safety: during loading/unloading, bonding cables are used to ground the truck and prevent static discharge. This is especially important for LH_2 transfers. No ignition sources are allowed within a defined zone. Personal protective equipment is worn for CH_2, usually flame-resistant clothing and safety glasses. For LH_2, cryogenic gloves and face shields are used to protect from ultra-cold contact or gas. Facilities have emergency shutdown (ESD) systems that the operator or automatic detectors can trigger to close valves and stop pumps/compressors. Vent systems, like vertical vent stacks, are installed to disperse any hydrogen released at height, preventing accumulation at ground level. Hydrogen's broad flammability (4–75% in air) and low ignition energy mean that even small leaks need immediate attention. Detectors for hydrogen are placed near connections and in enclosed spaces of the vehicle for instance, in cabinet compartments housing valves.

Training drills are conducted so that drivers and receiving personnel know how to handle emergencies like a pull-away (driving off with a hose attached) or a stuck valve. Industry guidelines (e.g. from EIGA and CGA) provide best practices on "defensive parking" (keeping distance from crowds, no tunnels unless allowed, etc.) and procedures if the tanker must vent gas to relieve pressure [16].

Advantages/disadvantages

The main advantages of truck-based hydrogen transport are:

- High flexibility and adaptability as hydrogen can be delivered to sites without access to pipelines.
- Lower capital investment and faster deployment compared to pipeline infrastructure.
- Scalable, modular and suitable for early market deployment and decentralized supply chains.
- Compatible with existing road logistics and intermodal transport (especially with containerized formats).
- Enables temporary or mobile supply, including as backup to stationary infrastructure.

The main disadvantages of truck-based hydrogen transport are:

- Higher unit cost of energy delivery compared to pipelines.

- Specialized handling required with trained personnel and safety protocols for high-pressure or cryogenic systems needed.
- Limited payload capacity due to weight and volume constraints, especially for compressed hydrogen, and boil-off losses for LH_2 during transport and storage.
- Practical constraints such as longer unloading times, road traffic exposure, and more frequent refuelling logistics.

A summary of advantages and disadvantages of hydrogen transport by truck compared to pipeline are:

Aspect	Advantages (vs. Pipeline)	Disadvantages (vs. Pipeline)
Flexibility	Can reach off-grid or remote users; ideal for early-phase or decentralized supply.	Limited scalability for high-volume, long-distance transport.
Costs	Lower initial investment; no need for permanent infrastructure.	Higher OPEX per kg due to vehicle, fuel, and labour costs.
Deployment speed	Fast to deploy; no lengthy permitting or construction processes.	Shorter asset lifetime and higher maintenance needs.
Infrastructure footprint	Minimal land use and permitting complexity.	Traffic congestion, road wear, and dependence on public road networks.
Scalability	Modular and incremental scaling possible with trailer additions.	Cannot match pipeline throughput beyond certain volumes or distances.
Operational range	Ideal for <200–300 km deliveries and payloads <2 t.	Becomes uneconomical and infeasible for longer distances or larger volumes.
Permitting & regulation	Easier to permit than pipelines; faster approval.	Must comply with strict road transport regulations and weight limits.
Dual use as storage	Tube trailers can act as temporary storage at user sites.	Storage volume is limited and inefficient compared to fixed tanks or pipeline linepack.

In general, transport by truck is only feasible for small amounts. An example calculation for transporting hydrogen over 100 km shows, that a 2.5 tonne truck is financially more favourable than a pipeline for amounts less than 15.000 tonnes of hydrogen per year.

Environment

Several environmental impacts are introduced by road transport of hydrogen by truck:

- GHG emissions and particulate matters are emitted from diesel-powered trucks that transport hydrogen, therefore switching to low or zero carbon emissions fuelled truck would mitigate this.
- Noise pollution and increased road traffic caused by trucks impact both local communities and wildlife.

- Trucks cause road wear especially with high axle loads. As truck transporting H_2 require more trips compared to other fuels, especially for high volumes, this accelerates strain on roads and bridges.
- Leakage of hydrogen to the atmosphere has an indirect GHG effect, which under normal operations is minimal.

Research and development perspectives

Ongoing R&D in hydrogen road transport focuses on improving safety, efficiency, and cost-effectiveness through advanced technologies. Key innovations include lightweight Type IV composite cylinders that double trailer payloads, modular container systems for flexible and scalable logistics, and improved insulation for liquid hydrogen that minimizes boil-off. High-efficiency cryogenic pumps reduce energy use and transfer losses, while standardization of trailer designs across components and pressures enables interoperability, lowers manufacturing costs, and simplifies regulatory approval. All this research and developments together are advancing the performance and usability of hydrogen trucks.

Examples of market standard technology

Both tank trucks and containerized trucks for CH_2 and LH_2 are example of market standard technology, as explained in *Description of options for road transport.*

Quantitative description

The total cost of hydrogen transport by road, accounting for both CAPEX and OPEX, is modelled as a function of capacity and distance. It consists of two main components: a fixed cost (EUR/ton H_2) and a variable cost part (EUR/ton H_2* km). Overall, the total cost can be expressed as:

$$Total\ H_2 transport\ cost = fixed\ cost + variable\ cost$$

Both fixed and variable cost components include part of CAPEX and OPEX. Specifically, they include the same cost elements such as annualized CAPEX, fixed O&M, and driver wages, but are weighed differently depending on how the truck is utilized throughout the year. The fixed cost reflects periods when the truck is stationary such as, during loading, unloading, or idle time. The variable cost accounts for the time spent driving. Fuel consumption is only included in the variable cost. The share of time spent driving versus stationary depends on factors such as truck availability, trip duration, and loading/unloading times. Based on this method, the total cost per ton of hydrogen transported annually can also be expressed as

$$Total\ H_2\ trasnport\ cost = \frac{total\ annual\ cost * Idle\ time\ share}{Annual\ H_2\ transported} + \frac{(total\ cannual\ cost * Driving\ time\ share) + fuel\ cost}{(Annual\ H_2\ transported * distance)}$$

The following assumptions, representative of CH_2 transport, are used to estimate the fixed cost and variable cost components that are further reported in the catalogue data sheet.

- CAPEX of the hydrogen truck is assumed 800.000 EUR. Hydrogen trucks can transport 1.3 tons of hydrogen per trip.
- Annual fixed OPEX is assumed 5% of hydrogen truck CAPEX.

- The driver's cost is 40 EUR/hour, with operation 24/7.
- Fuel cost for diesel is 47 EUR/kJ, with fuel consumption of the hydrogen truck assumed to be 18 MJ/km.
- The average truck speed is 50 km/h.
- Loading and unloading time is 120 minutes each (4 hours roundtrip).
- The truck availability is 8000 hours per year.
- Annualized CAPEX is calculated by assuming 10 years of technical lifetime and 7% of interest rate (WACC).

Based on such assumptions, the total H_2 cost is modelled as reported in Figure 22.

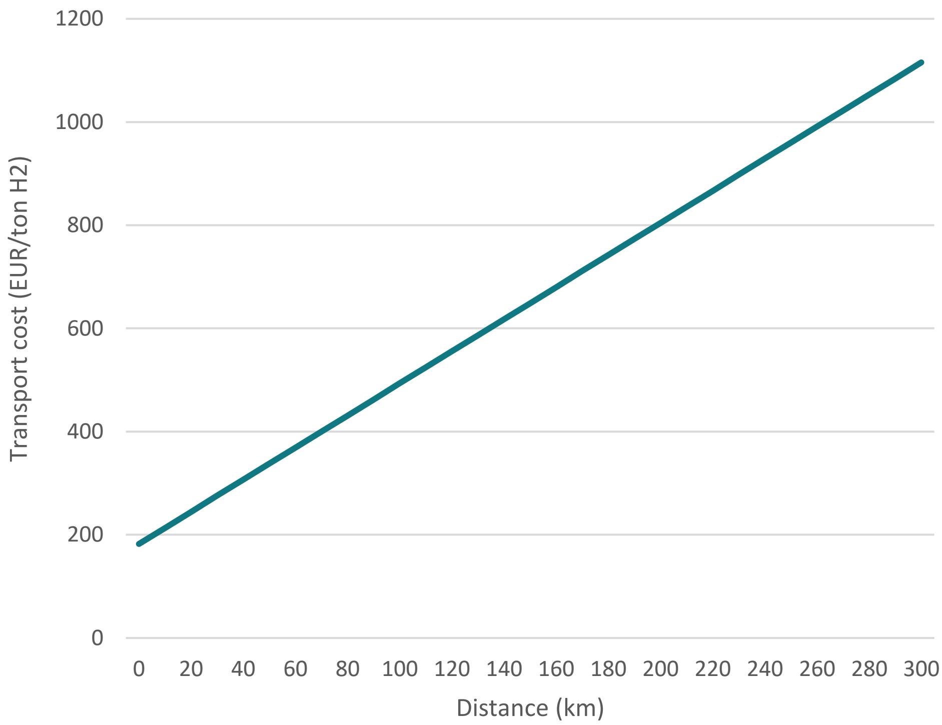

Figure 22: Modelled total hydrogen transport cost by truck (fixed + variable) as a function of distance.

Overall, LH_2 enables a greater payload capacity compared to CH_2, allowing for the transport of more hydrogen. This results in fewer trips required to supply a given volume (assuming the same number of trucks), or alternatively, it reduces the number of trucks needed for operations. Consequently, due to the lower delivery frequency, lower fuel and driver costs per kg of hydrogen are expected in LH_2 compared to CH_2. However, the high fixed cost for investment in liquefaction plant and cryogenics storage need to be offset. In CH_2 transport, capital investments in compressor systems at the filling station or depot are still needed but are yet expected to be lower than for LH_2.

On the operational level, CH_2 has virtually no boil-off losses, and if properly equipped, nearly all delivered hydrogen can be utilized. Energy needed for compression in CH_2 is not a negligeable cost, but at the same time, the cost of energy is also present in LH_2 for the liquefaction process and maintaining the cryogenic operation. Overall, LH_2 delivery tends to be economically favoured over CH_2 for high volumes and large distances, whereas CH_2 is better over short volumes and distances. Some analysis shown that LH_2 is more economical than CH_2 for demand above 300 kg hydrogen per day [18].

Available data does not consistently and clearly distinguish the cost and performance differences between tank trucks and containerized tanks, or between CH_2 and LH_2 delivery in practice. Key granular cost estimates remain underexplored. Qualitative insights suggest containerized systems may reduce costs in modular networks by enabling mobile storage and faster turnaround, while fixed tank trucks may offer higher capacity and optimized refuelling logistics. As the sector evolves, more detailed comparisons will be needed to identify the most cost-effective solutions.

Uncertainty

Hydrogen transport by truck, both CH_2 and LH_2 form, falls under Category 3 of "Commercial technologies with moderate deployment". The technology is already in use across Europe and globally, particularly for refuelling stations and industrial gas customers. However, its cost and performance at scale remain uncertain. Upscaling challenges include supply chain constraints (e.g. availability of Type IV cylinders or LH_2 infrastructure) and regulatory harmonization across markets. Additionally, cost efficiency depends heavily on utilization rates, fuel logistics and ongoing improvements in insulation, vessel design, and loading systems. Future costs may decline with upscaling and standardization, but questions remain about competitiveness for high-volume and long-distance delivery.

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