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 |
|---|---|---|
| **Feb 2025** | 113 | 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** | 121-123 now 421-423 | 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** | 131-133 | Addition of chapters on transport of gases and liquids including introduction to the topic |
| **Nov 2020** | 121-123 | 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.

## Index

## 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

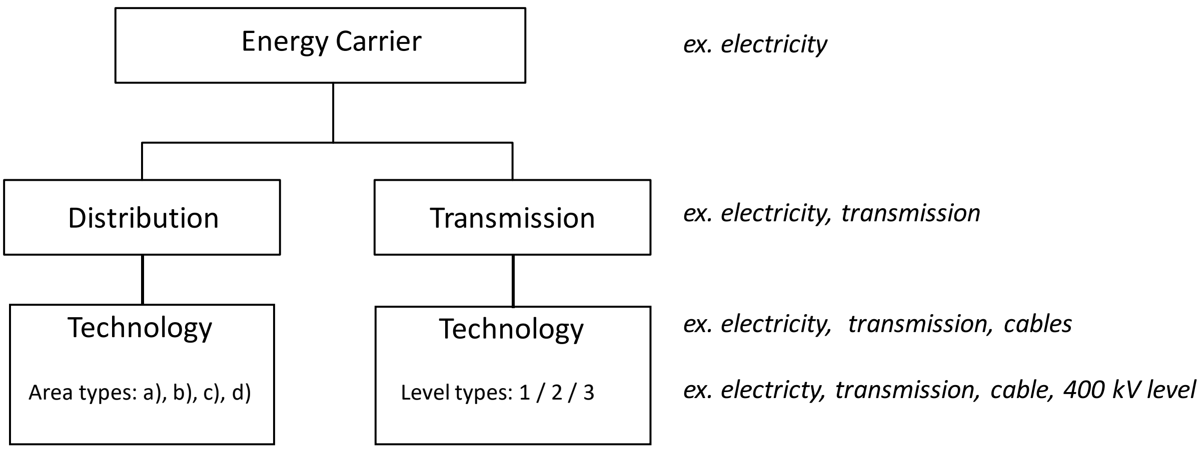
Other energy transport systems such as networks for hydrogen, biogas etc. as well as road and sea transport of liquid and solid fuels are not included. Energy storage installations in the respective systems are treated in a separate catalogue on energy storage. The catalogue does not contain prices for 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.

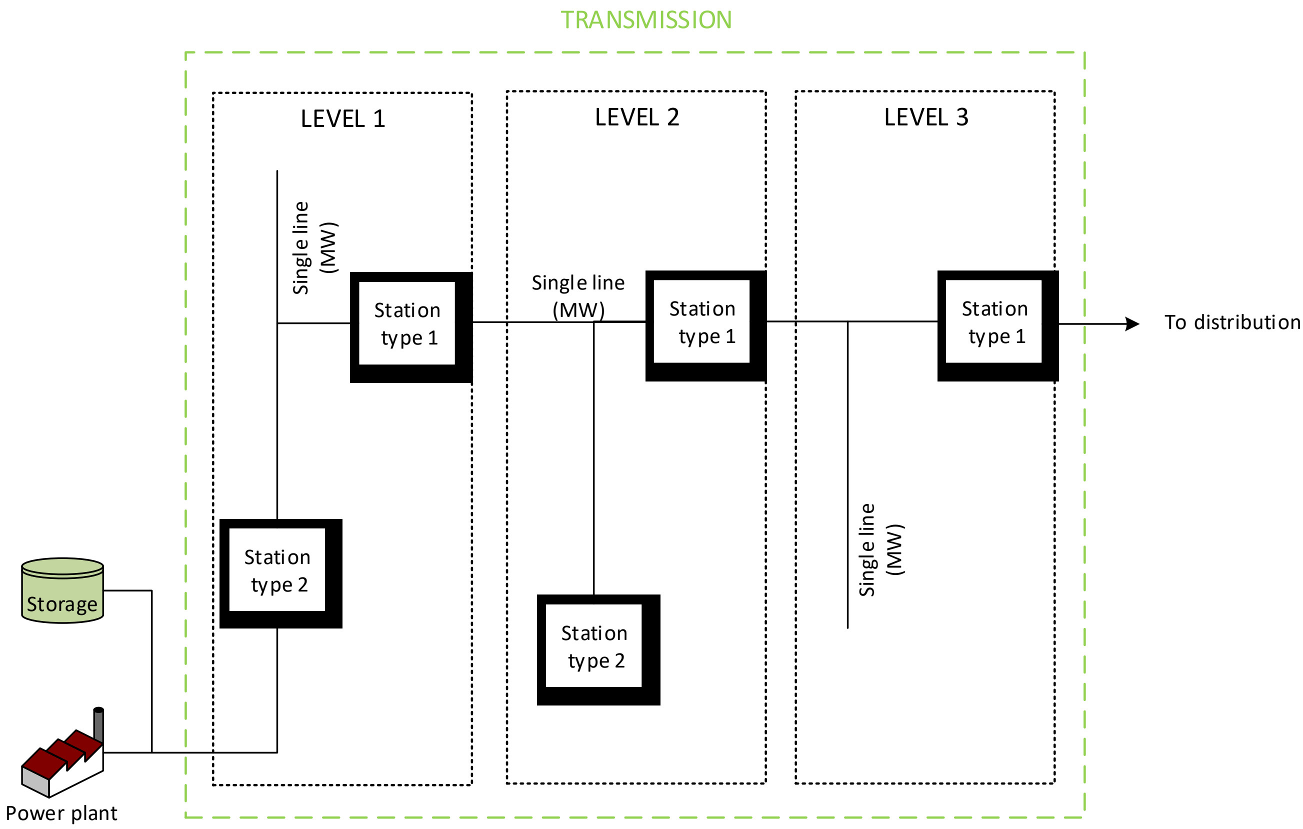
For each of the transmission technologies a number of levels are defined corresponding to the relevant voltage, pressure, or temperature levels. Separate data sheets are provided for each transmission level. For some technologies only one level is relevant.

| **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 |
| Electricity, HVDC | 400 kV | | |
| Electricity, HVDC Sea cables | 250-400 kV DC | | |
| Electricity, HVAC Sea 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]**<br>**(level change)** | **Stations [type 2]**<br>**(auxiliary service)** |
|---|---|---|
| Natural Gas | - M/R station (pressure release)<br>- Compressor | |
| Electricity, overhead lines | Transformer station | - Capacitor banks<br>- Reactors |
| Electricity, cables | Transformer station | - Capacitor banks<br>- Reactors |
| Electricity, HVDC | Converter station | |
| 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.

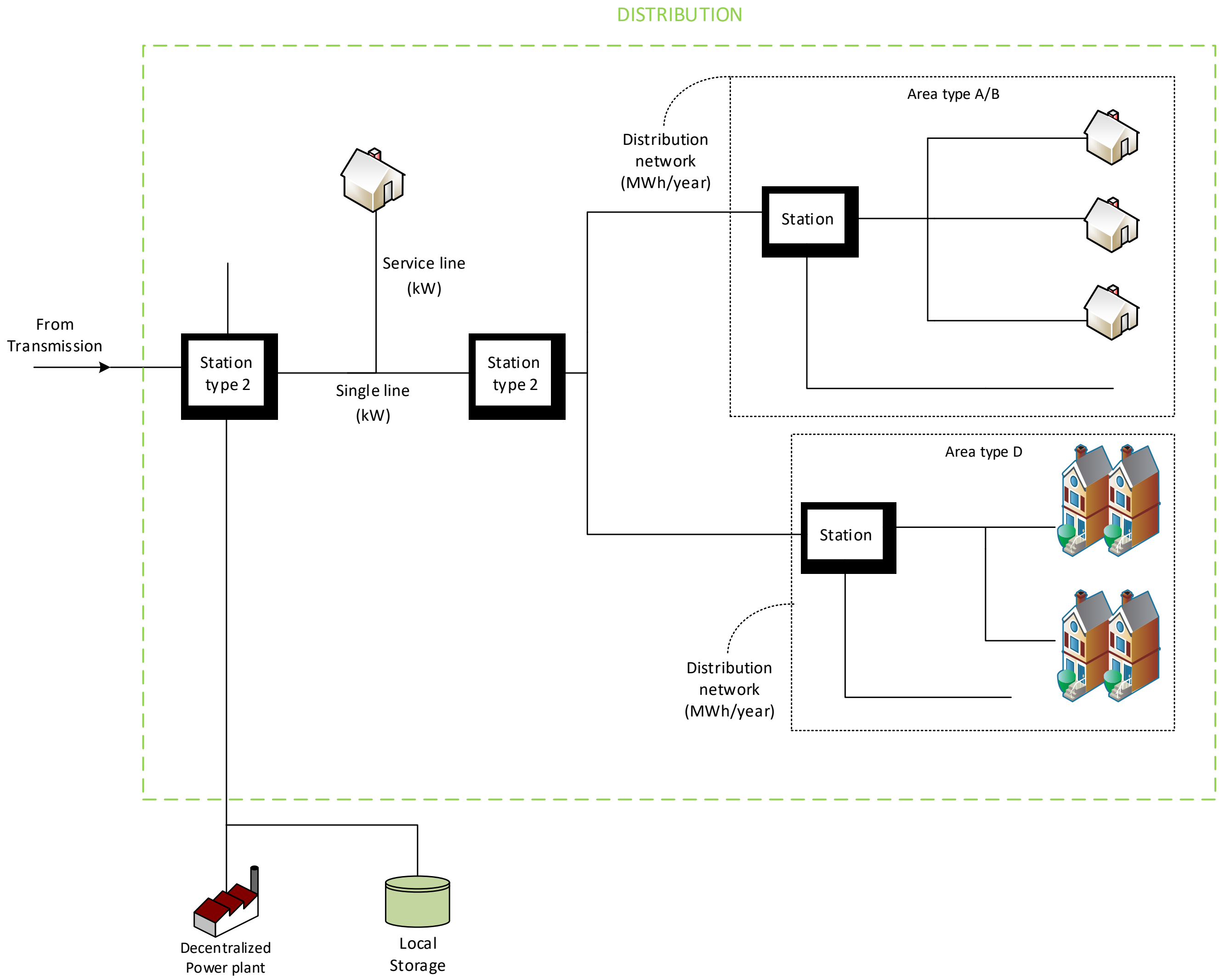
For a certain distribution technology, a number of different station types may be relevant:

| **Distribution** | **Stations [type 1] (level change)** | **Stations [type 2] (auxiliary service)** |
|---|---|---|
| Natural Gas | D/R station | |
| Electricity, overhead lines | Transformer 10/0.4 kV | |
| Electricity, cables | Transformer 10/0.4 kV | |
| 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<br>• Natural gas, 40-16 bar<br><br>• Electricity, overhead lines, 400 kV<br>• Electricity, overhead lines, 132/150 kV<br>• Electricity, overhead lines, 50/60 kV<br>• Electricity, cables, 400 kV<br>• Electricity, cables, 132/150 kV<br>• Electricity, cables, 50/60 kV<br>• Electricity, HVDC, 400 kV<br>• Electricity, HVDC sea cable, 250-400 kV<br>• Electricity, HVAC sea cable, 400 kV<br>• Electricity, HVAC sea cable, 132/150 kV<br>• Electricity, HVAC sea cable, 50/60 kV<br><br>• District heating, < 110 deg. C / 25 bar<br>• District heating, < 80 deg. C | • Natural gas, area type a)<br>• Natural gas, area type b)<br>• Natural gas, area type c)<br>• Natural gas, area type d)<br><br>• Electricity, cables, area type a)<br>• Electricity, cables, area type b)<br>• Electricity, cables, area type c)<br>• Electricity, cables, area type d)<br><br>• District heating, area type a)<br>• District heating low temp., area type a)[1]<br>• District heating, area type b)<br>• District heating, area type c)<br>• 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. 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)

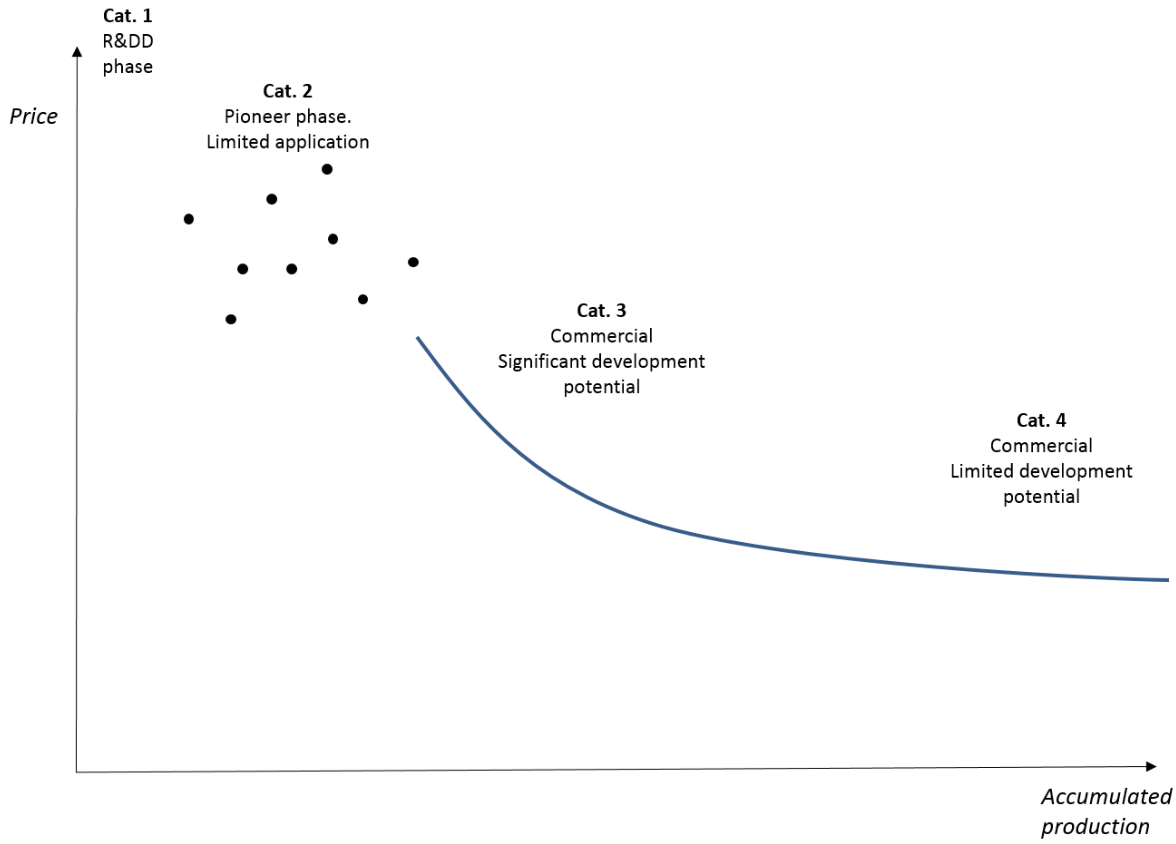



**Figure 1: Technological development phases. Correlation between accumulated production volume (MW) and price.**

## 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.

# 111 Electricity distribution grid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| Date | Ref. | Description |
|---|---|---|
| - | - | - |
| - | - | - |

## Qualitative description

### Brief technology description

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 power at low loss and transmission lines use voltage ranges from hundreds of kilovolts and up. Near customers the voltage is reduced in several steps by step-down transformers and transported by distribution line to users. The major components of an electric power system are illustrated in figure 1 [1].

The electrical grid is a fundamental part of the infrastructure in all developed countries. The electrical grid enables interconnection of a large numbers of producers and consumer, which results in a flexible system with very high reliability. Interconnected electrical networks also pave the way for introduction of large amounts of renewable electricity sources.

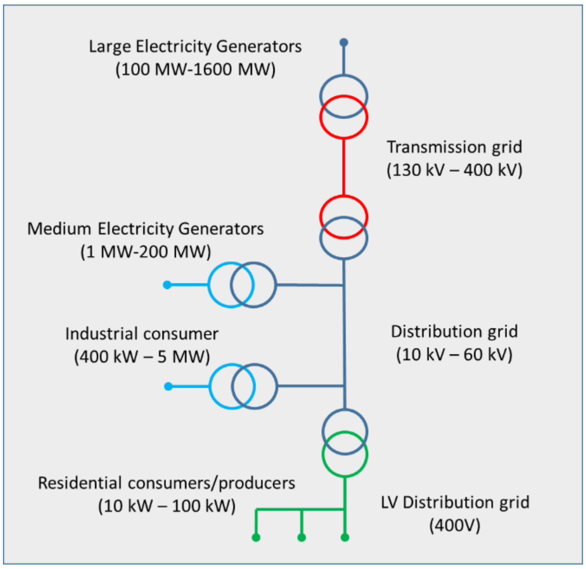


**Figure 1: Major components in an electric power grid**

## Input

Historically, electrical power is generated at utility scale by electrical power plants such as thermal power plants, hydropower plants, and nuclear power plants with power levels in the range of a few hundred kW up to 1000 MW levels. 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 steam that drives a turbine-generator set that produces electricity. Thermal plants, especially gas power plants, have high ability to regulate power. Hydropower uses potential energy of water in rivers to drive turbine-generator sets. Hydropower has a high ability to regulate power and can regulate power on sub-second levels. The water in the dams of hydropower plants represents an energy storage that can be used to balance power on a yearly basis. The turbine-generator sets of thermal, nuclear and hydropower plants have, thanks to the large masses and high rotating speed, a significant inertia. This inertia provides stability to the power system and is an important factor for grid stability and reliability. Utility scale power plants are connected directly to the transmission network by a step up transformer and are often situated away from demand centers.

Over the last 30 years there has been an increase of renewable electricity generators, which has accelerated the last 15 years. Since 2007 the share of solar photovoltaics (PV) and wind power have represented over 50 % of new power capacity installed in Europe. In 2015 22 GW capacity of renewable electricity was installed, representing 77 % of all capacity installations in Europe that year [2]. Denmark has been a pioneer in developing commercial wind power. In 2015 wind power produced the equivalent of 42 % of Denmark's total electricity consumption, the highest proportion for any country [3]. Wind power plants and solar power plants have powers ranging from a few MW to several 100 of MW. Smaller plants are connected to the distribution grid but larger plants are connected to the transmission grid. Unlike traditional power plants, regulating capacity and inertia is limited for wind power and PV.

An increasing trend is domestic PV, where private households and commercial buildings have a few kW of installed PV on the rooftop. The PV facility is connected to the low voltage system of the building and the power is used by the owner and surplus delivered to the electrical grid.

### Output

Electric power has a vast usage in the residential, commercial and industrial sector. In the residential sector electricity is used for lighting, washing, refrigeration, cooking, heating and entertainment. Average energy consumption per capita in Denmark is 1,600 kWh per year. This is dominated by entertainment (tv, computer, stereo, etc.), which accounts for 40% of electricity consumption. Electricity usage for heating (direct, central electric heating and heat pumps) is low in Denmark (4%) compared to *e.g.* Sweden where 30 % of the energy used for heating is electrical energy. 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 transportation (cars, trains, trams and subways) sector represents a small part of total electricity usage in Denmark (1.5%) [4] [5] [6].

### Energy balance

In an electrical system all the electricity production needs to be continuously balanced with the consumption and losses. The transmission system operator (TSO) is responsible for this balance and maintains a second-by-second balance between electricity production supply from producers and demand from users. Intraday balance is handled by the electricity market where production supply is purchased based on projected demand. Fluctuation in shorter time frames is handled by a regulating power market, where changes in production and consumption can be carried out on second, minute and hour basis. Energinet.dk is the TSO of Denmark and is in charge of ensuring the physical balance of the Danish electric power system. Energinet.dk is part of the common Nordic regulating power market [7]. Introduction of large amounts of intermittent power increases the need for regulation. As a result, electric energy storage is implemented on utility scale in *e.g.* UK [8]. Electricity transportation incurs losses in the form of thermal losses in the conductors. The total energy loss of an electrical system lies in the range of 6%-10% in developed countries [9] [10] [11]. In Denmark the total losses vary between 6%-9.5%, where 1%-2% stem from the transmission grid and 4%-6.5% stem from the distribution grid.

### Description of transmission system

The electrical 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 ranges from 100 MW to several GW. The transmission grid in Denmark operates at 132 kV to 400 kV. The transmission grid consists mainly of overhead lines, but high voltage cables are increasing in share especially in densely populated areas. Transformer stations step up and down voltages between different parts of the transmission network and to producers and distribution grids. Compensation stations are used to enhance controllability and increase power transfer capacities of the transmission grid. Capacitive or reactive power is provided by means of capacitor banks, flexible alternating current transmission systems (FACTS), etc. High Voltage DC connections are used in the transmission grid to transport large amounts of energy long distances. HVDC connections can also be used to interconnect regions with different frequencies. Transmission systems interconnect vast areas into synchronous grids, where a large number of generators deliver power with the same electrical frequency to a large numbers of users. Denmark has two separated transmission systems, of which the eastern one is synchronous with Nordic countries and the western one is synchronous with the grid of Continental Europe [12]. Large interconnected transmission systems enable optimal power dispatch between a large number of power generators with different characteristics, enhance system reliability, and are necessary to efficiently handle an increasing amount of intermittent energy sources.

### Description of distribution system

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 neighboring 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. In agricultural land the space requirement is limited to the poles and stays. In forest a 400 kV overhead line needs a clearance of 40 m – 50 m where no trees are allowed to grow and additional 10 meter on each side where tree height is limited. In populated areas a clearance zone of 38 meter width is set for non-residential buildings, whereas a clearance of approximately 200 m width is required for buildings where human reside permanently in order to avoid exposure of magnetic fields. The space requirement reduces with lower voltages and for distribution grid the clearance in forest ranges from 4 - 22 m width [13] [14]. Electric cables have a significantly lower space requirement. In populated areas and cities, cables are normally laid close to or in roads and streets. Ground cables do not affect the use of agricultural land.  As far as possible, medium voltage cables follows roads also in rural areas. In forest, 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 and for distribution grids the clearance is 4 m. The magnetic field from cables is smaller than for overhead lines and does not add to the space requirements.

| | Agricultural land | Forest | Populated area |
|---|---|---|---|
| Transmission overhead lines | negligible | 0,1-0,35 | 0,3-2 |
| Transmission cables | negligible | 0,02-0,1 | 0,02-0,1 |
| Distribution overhead lines | negligible | 0,4-1,1 | 1 - 3 |
| Distribution cables | negligible | 0,1-0,2 | 0,1-0,2 |

**Table 1: Space requirements, square meter per MW per meter.**

### Advantages/disadvantages

Electricity is an essential part of modern life and the electric grid is a natural and integral part of the infrastructure in developed countries. High voltage transmission grids enable long distance transportation of vast amounts of energy with 97% to 98% efficiency. The transmission grid forms, together with the distribution grids, a power transmission system that enables energy transportation from a range of different electricity production facilities to a large range of end users. The end-to-end efficiency of the electricity system ranges between 90% to 94% and the reliability is very high. The Danish security of supply of electrical power is 99,996%, which corresponds to an average outage of electricity of 15 minutes per year [15]. Furthermore, a large, integrated electrical grid is a prerequisite for increased amounts of intermittent renewable electricity, such as wind and solar power. This will be essential in the transition to fossil-free energy systems [16].

On the contrary, electric energy production in the EU is still dominated by non-renewable energy sources such as fossil fuels and nuclear plants. In order to increase the renewable electricity share the electrical grids needs to be more flexible and the level of integration between regions needs to be increased further.

**HVDC vs HVAC**

A vast majority of electric transmission systems today use three phase High Voltage Alternating Current (HVAC). A majority 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 High Voltage Direct Current as a highly efficient alternative for transmission of electric power and for interconnecting power grids with different frequencies. HVDC requires terminal converter stations with relatively high costs, which is not required by HVAC. The cost per distance is however lower for HVDC systems, due to smaller space requirements, reduced number of conductors and reduced losses. HVDC also enables longer cable transmission due to the lack of capacitive losses that are apparent in AC cables. Above a specific distance, called break-even distance, HVDC technology becomes cheaper than HVAC. The break-even distance for overhead lines is around 600 km and for cables lines it is around 50 km. HVDC also enables a number of additional benefits, such as enhanced voltage regulation and controllability, ability to interconnect regions with different frequencies, reduced short circuit current in AC system, etc. Often the choice between HVDC and HVAC is based on economical, technical and environmental judgments [17] [18].

**Overhead lines vs cables**

A majority of the transmission grid is composed of overhead lines. Overhead lines offer significantly lower construction costs and lower capacitive losses. On the contrary, the space requirements of overhead lines are significantly larger than for cables (200 m vs 15 m) and visual impacts are significant. For high voltage long distance transfer in unpopulated areas, overhead lines are often the preferred choice. In populated area, cables can provide an attractive solution, mainly due to the small land intrusion. In densely populated areas, cables often provide the only technically viable solution. The transmission grid in Denmark consists of 4,900 km of overhead lines and 1,900 km of cables [19] [20].

Distribution grids have seen a significant change towards underground cables. The motivation for this is the increase in reliability that is provided by avoiding overhead lines, sensitive to storms. Cabling of the distribution grid in Denmark has already had noticeable effect on system reliability. While cables in distribution grids are less susceptible to faults, once a fault has occurred it is more difficult to locate and amend than if the fault is in an overhead line.

## Environment

The environmental impacts of the electrical grid are mainly [21]:

- 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 are 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 soils 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.

## Research and development perspectives

The electric power system in Europe is changing. The main drivers of the changes are climate policy and technological developments. Climate policy has stimulated the development of new renewable energy sources. The share of wind and solar power has increased from a marginal level in the end of the 20-th century to an impressive 26 % of the EU power mix in 2015. This represents a significant change to the electric power system in Europe and the electric grid plays a central role as facilitator for the ongoing and continuing expansion of large amounts of intermittent energy sources [2][16][22]. Some of the ongoing research and development activities in this area are listed below:

- Development of a common European framework for market operation and planning.
- Implementation of Smart grids with a significant level of customer flexibility
- Energy storage – both decentralized and at utility scale. Electric energy storage is currently at a very low level in Denmark. Price development for batteries and the need for system services, such as frequency control, have today resulted in commercial utility scale battery storages in e.g. UK and US. It is has also become economically attractive in an increasing part of the world for households to install local battery storages in combination with solar PV.

### Examples of market standard technology

**Skagerrak 4** – Submarine HVDC-light interconnection between Denmark and Norway. The link has a voltage rating of 500 kV and a capacity of 700 MW. The link is composed of two converter stations, 90 km of land cables and 130 km of submarine cables. It will enable more renewable electricity and more efficient use of electricity [23][24].

**SouthWest link** - A combined AC- and DC transmission line connecting the South of Sweden with Central Sweden. The link is composed of three AC substations, two converter stations, underground cables and overhead lines. The total capacity will be 2 x 600 MW and the total length is 430 km [25].

### Prediction of performance and costs

Predictions of cost are made from two data sets:

- EBR cost data base which is a complete, detailed and precise cost data base covering labor cost, material cost and O&M in the Swedish power grid sector [26].
- Standard value list for the Swedish Energy Markets Inspectorate, which is an unbiased and detailed database of costs in the power grid sector developed by the regulatory authority [27].

Data are correlated to Danish market conditions by benchmarking key figures with Danish project experiences.

The electricity grid is a mature and commercial technology with large deployment. Price fluctuations have been low during recent years and the price development has more or less stabilized over the last six years. No large changes in costs and performance are expected to happen on current technology in the foreseeable future. However, new technology, changes in production methods and changes consumption behavior will possibly overturn the prerequisites of our current electrical grid.

### Uncertainty

Performance data of electrical grid, such as energy losses, technical life time and load profile typically depends on techno-economic-political considerations such as amount of energy transfer to adjacent countries, value of energy loss, life time 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.

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## Data sheets

### Table 1: Main distribution, 50/60 kV electricity

| Technology | Electricity Main distribution, electricity cables | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2020 | 2030 | 2050 | Uncertainty (2020) | | Uncertainty (2050) | | Note | Ref |
| **Energy/technical data** | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines 1-20 MW (%) | 0,30 | 0,30 | 0,30 | 0,30 | 0,30 | 0,5 | 0,15 | 0,5 | A,B | 1,2,3,4 |
| Energy losses, lines 20-100 MW (%) | 0,30 | 0,30 | 0,30 | 0,30 | 0,30 | 0,5 | 0,15 | 0,5 | A,B | 1,2,3,4 |
| Energy losses, lines above 100 MW (%) | 0,30 | 0,30 | 0,30 | 0,30 | 0,6 | 0,5 | 0,15 | 0,5 | A,B | 1,2,3,4 |
| Energy losses, stations [Type 1] (%) | 0,2 | 0,2 | 0,2 | 0,2 | 0,2 | 0,25 | 0,1 | 0,25 | A,B | 1,2,3,4 |
| Energy losses, stations [Type 2] (%) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | A,B,S | |
| Auxiliary electricity consumption (% energy transmitted) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | A,B,S | 4 |
| Technical life time (years) | 40 | 40 | 40 | 40 | 35 | 40 | 40 | 50 | C | 5 |
| Typical load profile (-) | 45% | 45% | 45% | 45% | 45% | 45% | 42% | 54% | D | |
| Construction time (years) | 1,5 | 1,5 | 1,5 | 1,5 | 1 | 5 | 1 | 5 | E | |
| | | | | | | | | | | |
| **Financial data** | | | | | | | | | | |
| Investment costs; single line, 0 - 50 MW (EUR/MW/m) | 6,0 | 6,0 | 6,0 | 6,0 | 5,4 | 6,0 | 4,86 | 6,0 | F,G | 6,7 |
| Investment costs; single line, 50-100 MW (EUR/MW/m) | 3,9 | 3,9 | 3,9 | 3,9 | 3,51 | 3,9 | 3,159 | 3,9 | H,G | 6,7 |
| Investment costs; single line, 100 - 250 MW (EUR/MW/m) | 3,1 | 3,1 | 3,1 | 3,1 | 2,79 | 3,1 | 2,511 | 3,1 | I,G | 6,7 |
| Investment costs; single line, 250-500 MW (EUR/MW/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | J | 6 |
| Investment costs; single line, 500-1000 MW (EUR/MW/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | J | 7 |
| Investment costs; single line, above 1000 MW (EUR/MW/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | J | 8 |
| Reinforcement costs (EUR/MW) | 15.800 | 15.800 | 15.800 | 15.800 | 15073 | 15800 | 14380 | 15800 | K,O | 6 |
| Investment costs; [type 1] station (EUR/MW) | 76.000 | 76.000 | 76.000 | 76.000 | 72504 | 76000 | 69169 | 76000 | L,O | 8 |
| Investment costs; [type 2] station (EUR/MW) | 4476 | 4476 | 4476 | 4476 | 4270 | 4476 | 4074 | 4476 | M,O | |
| Investments, percentage installation | 42% | 42% | 42% | 42% | 37% | 42% | 33% | 42% | P | 6 |
| Investments, percentage materials | 58% | 58% | 58% | 58% | 58% | 63% | 58% | 67% | P | 6 |
| Fixed O&M (EUR/MW/km/year) | 22,1 | 21,8 | 21,5 | 21,2 | 21,7 | 22,1 | 20,9 | 22,1 | Q | 9 |
| Variable O&M (EUR/MWh/km) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | R | |

***Notes***

A Energy losses are estimated from total energy loss on transmission levels in the voltage range 20kV to 130 kV in Sweden. Transmission lines/cables accounts for approximately 60% of the losses and transformers accounts for approximately 40%.

B Development of energy loss over time depends on several factors. Today, transmission losses typically range between 1% to 3% in Denmark. The variation in transmission losses depends mainly on the amount of power transfer to neighboring countries. The trend in Denmark is towards increasing transfer and thus increasing losses. The uncertainty span for 2020 mainly takes changes in power transfer into account, where the lower bound corresponds to a reduction of power transfer to a 1998 level, and the upper bound corresponds to a continued increase in losses stemming from increased power transfer.
Technology development with introduction of e.g. super conducting transformers and super conducting power lines could lead to reduced losses on transmission level. Other factors, such as load control/optimization could also reduce losses in generators due to increased load factor. This technology development is not anticipated to have effect before 2020, but is possible in a second upgrade of electricity system in 2050.

C Cable life length depends on material characteristics and the thermal loading of the cable. Increasing cable area and thus reducing cable temperature leads to longer life length. Today, up to 40 years are realistic life length of a cable with moderate thermal loading. Technological development on cable materials is anticipated to give an increase in cable life length. This in combination with low thermal loadings could give life length of up to 50 years in the future.

D Load profile varies significantly between different stations and cables and a general figure is given. The load profile is not expected to change to 2020. For 2050 the upper scenario is a smart grid scenario, in which the load factor increases by 6 %, the lower scenario is an increase in peak load without the use of smart grid leading to a decrease in load factor by 20%.

E Construction time ranges normally from 1 to 2 years. In technically complex projects and for long cable stretches, the construction time increases and could stretch up to 5 years.

F Costs are based on data for cables with design voltage of 72 kV and a operation voltage of 50 kV. Cost is calculated as the average cost between rural areas, dense populated areas and city areas. Adjusting factors for each area are: rural areas: 0,75, dense populated: 1,04, and city: 1,2.
For power range 0 - 50 MW the costs is calculated as the average cost of two cables types with cross section areas 240 $mm^2$ and 630 $mm^2$, corresponding to power levels of 20-35 MW and 50-60 MW respectively. The cost per MV decreases with increasing power level. The interval 20-35 MW has a cost of 6,7 EUR/MW/m and the interval 50-60 MW a cost of 4,2 EUR/MW/m. An increase in operation level to 60 kV will decrease the cost by a factor 0,9. Power level below 20MW is not considered for this voltage level.

G Price projections are based on an extrapolation of price development over the years 2000 - 2014 corrected for inflation. Over the six last years the prices have stabilized on a costant level and it is assumed that prices will remain stable. Lower uncertainty bounds for 2020 assumes a reduction of 10% of the costs due to more efficient installations and a continued reduction by an additional 10% for 2050. No increases in costs are anticipated and upper bounds are set to today's level for both 2020 and 2050.

H Costs are based on data for cables with design voltage of 72 kV and a operation voltage of 50 kV. Cost is calculated as the average cost between rural areas, dense populated areas and city areas. Adjusting factors for each area are: rural areas: 0,75, dense populated: 1,04, and city: 1,2.For power range 50-100 MW the costs is calculated as the average cost for three cables with cross section areas 630 $mm^2$, 800$mm^2$ and 1000 $mm^2$, corresponding to power levels of 50-60 MW, 69 MW and 76 MW respectively. The cost per MV decreases with increasing power level. The power interval 50-60 MW has a cost of 4,2 EUR/MW/m, at power level of 69 MW the cost is 3,6 EUR/MW/m and at the power level 76 the cost is 3,4 EUR/MW/m. An increase in operation level to 60 kV will decrease the cost by a factor 0,9.

I Costs are based on data for cables with design voltage of 72 kV and a operation voltage of 60 kV. Cost is calculated as the average cost between dense populated areas and city areas. Adjusting factors for each area are: dense populated: 0,94, and city: 1,06. For power range 100-250 MW the costs is given for a cable with cross section area of 1200 $mm^2$, corresponding to a power level of 100 MW. Power levels above 100 MW are not considered for this voltage level.

J Power levels above 100 MW are normally transported at higher voltage levels. In cases where it is motivated to transport higher power levels at 50/60 kV, this is done in parallele cable budles in the same shaft. The cost of two parallel cables can be calculated as the double cost of one cable reduced with 60 800 EUR per kilometer.

K Reinforcement costs depends on where bottlenecks are situated in the grid. Here the reinforcement cost is given for an upgrade of transformer capacity by 40 MVA. Reinforcement of line/cable capacity is in parity with the investment cost in described in row 18 - 20 and depends on power level and cable length.

L Station cost is based on a 40 MW station with 2 x 20 MVA transformers (72/12 kV). Station cost depends on a number of factors, such as power rating, redundancy on transformers etc. Station cost have an almost linear relation to the power rating and following relation holds for the power span 20 - 126 MW: Station cost (EUR) = 16 000 (EUR/MW) x Power rating (MW) + 2 350 000 (EUR). Using a single transformer instead of two reduces the cost by a factor 0,86 - 0,87.

M Station cost is based on average cost for capacity banks and inductor with a design voltage of 72 kV. It is assumed that the equipment is installed in a existing station.

O Price projections are based on an extrapolation of price development over the years 2000 - 2014 corrected for inflation. Over the six last years the prices have stabilized on a costant level and it is assumed that prices will remain stable. Lower uncertainty bounds for 2020 assumes a reduction of 4,4% of the costs due to more efficient installations and a continued reduction by an additional 4,4% for 2050. No increases in costs are anticipated and upper bounds are set to today's level for both 2020 and 2050.

P The percentage of the investment cost allocated to material cost and installation cost varies depending on area type (rural or city) and power level. An average is given here. Lower uncertainty bounds for 2020 assumes a reduction of 17,6% of the investment costs due to more efficient installations and a continued reduction by an additional 10% for 2050.

Q The fixed O&M cost are calculated as a standard annual cost of 0,51% of the investment cost multiplied by the average cost of cables per MW and km given in row 18 to 20. It should be noted that the O&M cost in distribution system mainly is attributed to stations since there is practically no maintenance on cables. The O&M cost is assumed to be reduced over time by an annual factor of 1 - 1,8% due to increased efficiency. Upper uncertainty bounds for 2020 and 2050 corresponds to no efficiency increase in O&M and lower bounds corresponds to a continuous annual efficiency increase of 1,8%

R Variable O&M cost is in very low for electric transmission systems and considered to be negligible

S Energy losses and auxiliary electricity consumption can be considered negligible

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**Table 2: Electricity distribution, Rural**

| Technology | Electricity Distribution, Rural | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2020 | 2030 | 2050 | Uncertainty (2020) | | Uncertainty (2050) | | Note | Ref |
| **Energy/technical data** | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines (%) | 5,25 | 5,25 | 5,25 | 5,25 | 5,25 | 5,25 | 4,5 | 5,25 | A | 1 |
| Energy losses, stations (%) | 1,13 | 1,13 | 1,13 | 1,13 | 0,75 | 1,5 | 0,75 | 1,5 | B | 2 |
| Auxiliary electricity consumption (% of energy delivered) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N | 3 |
| Technical life time (years) | 40 | 40 | 40 | 40 | 35 | 40 | 35 | 50 | C | 4, 5 |
| Typical load profile (-) | 44% | 44% | 44% | 44% | 44% | 44% | 33% | 47% | D | 1, 5 |
| - Residential | 44% | 44% | 44% | 44% | 44% | 44% | 33% | 47% | D | |
| - Commercial | 44% | 44% | 44% | 44% | 44% | 44% | 33% | 47% | D | |
| Construction time (years) | 1 | 1 | 1 | 1 | 1 | 2 | 1 | 2 | | 5 |
| **Financial data** | | | | | | | | | | |
| Distribution network costs (EUR/MWh/year) Rural | 173 | 173 | 173 | 173 | 156 | 173 | 132 | 206 | E,F | 1, 6 |
| Investment costs; service line, 0 - 20 kW (EUR/unit) | 524 | 524 | 524 | 524 | 472 | 524 | 424 | 524 | G,F | 6 |
| Investment costs; service line, 20 - 50 kW (EUR/unit) | 1412 | 1412 | 1412 | 1412 | 1271 | 1412 | 1144 | 1412 | G,F | 6 |
| Investment costs; service line, 50-100 kW (EUR/unit) | 1583 | 1583 | 1583 | 1583 | 1425 | 1583 | 1282 | 1583 | G,F | 6 |
| Investment costs; service line, above 100 kW (EUR/unit) | 3745 | 3745 | 3745 | 3745 | 3371 | 3745 | 3033 | 3745 | G,F | 6 |
| Investment costs; single line, 0-50 kW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Investment costs; single line, 50-250 kW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Investment costs; single line, 100-250 kW (EUR/m) | 36 | 36 | 36 | 36 | 32 | 36 | 29 | 36 | H,F | 6 |
| Investment costs; single line, 250 kW - 1 MW (EUR/m) | 36 | 36 | 36 | 36 | 32 | 36 | 29 | 36 | H,F | 6 |
| Investment costs; single line, 1 MW - 5 MW (EUR/m) | 41 | 41 | 41 | 41 | 37 | 41 | 33 | 41 | H,F | 6 |
| Investment costs; single line, 5 MW - 25 MW (EUR/m) | 88 | 88 | 88 | 88 | 85 | 88 | 77 | 88 | H,F | 6 |
| Investment costs; single line, 25 MW - 100 MW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Reinforcement costs (EUR/MW) (Station) | 11500 | 11500 | 11500 | 11500 | 10994 | 11500 | 10510 | 11500 | I,F,J | 6 |
| Investment costs; [type 1] station (EUR/MW) | 67500 | 67500 | 67500 | 67500 | 64530 | 67500 | 61691 | 67500 | J | 6 |
| Investment costs; [type 2] station (EUR/MW) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Investments, percentage installation (cables) | 62% | 62% | 62% | 62% | 57% | 62% | 53% | 62% | K | 6 |
| Investments, percentage materials (cables) | 38% | 38% | 38% | 38% | 38% | 43% | 42% | 38% | K | 6 |
| Investments, percentage installation (stations) | 22% | 22% | 22% | 22% | 19% | 22% | 17% | 19% | K | 6 |
| Investments, percentage materials (stations) | 78% | 78% | 78% | 78% | 78% | 81% | 78% | 81% | K | 6 |
| Fixed O&M (EUR/MW/year) | 1628 | 1605 | 1583 | 1560 | 1599 | 1628 | 1541 | 1628 | L | 7 |
| Variable O&M (EUR/MWh) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | M | |

## *Notes*

A The line losses were calculated using reference (1) and the formula Total energy exported to customer / Total energy fed into the system. Lines in rural areas have a higher loss than lines in more populated areas.

B Losses in a transformer tends to decrease with increasing transformer capacity. The losses also depends on the transformer load. When the transformer load decreases under 20 % there is a large increase in the losses. In general the losses are about 1-2 %

C According to the network price regulation from Energimarknadsinspektionen, the technical life time for stations and cables are 40 years. In practice, cable technical life can be shorter, depending on the thermal loading of the cable.

D Calculations for the load profile were based on reference (1). This gave an average value of 44 % for all areas. The load profile is not expected to change to 2020. For 2050 the upper scenario is a smart grid scenario, in which the load factor remains the same, the lower scenario is an increase in peak load without the use of smart grid leading to a decrease in load factor by 19%.

E The distributions network costs are based on the average station cost and cable cost per customer divided by the average yearly energy transported to a customer. Assumptions on the average cable length per customer and the average number of stations per customer could be translated to a total distribution network cost per customer using the EBR cost database. Cost per MWh are affected both by changes in actual costs and changes in load factors. In 2020 load factors are assumed to be constant. Lower bounds assumes a reduction of 10% of the costs due to more efficient installations, no cost increased is assumed. For 2050 the lower bounds corresponds to a smart grid scenario with power factor increased by 15% in combination with a continued 10% cost decrease due to increased efficiency. The upper bound corresponds to a scenario where peak loads are increased by 15%, leading to reduced power factors and increased cost per MWh.

F Price projections are based on an extrapolation of price development over the years 2000 - 2014 corrected for inflation. Over the six last years the prices have stabilized on a constant level and it is assumed that prices will remain stable. Lower uncertainty bounds for 2020 assumes a reduction of 10% of the costs due to more efficient installations and a continued reduction by an additional 10% for 2050. No increases in costs are anticipated and upper bounds are set to today's level for both 2020 and 2050.

G Costs for service lines are based on cables with a design voltage of 0,4 kV. For each power level the corresponding current was calculated using a power factor of 0,90. The current corresponds to different cable areas and costs. Two cables were chosen for each interval (one for the lowest power level and one for the highest level in the interval). The average of these two costs was used in the table. The service line length was bases on the guidelines: 0-20 kW - 20 m, 20-100 kW - 50 m, Above 100 kW -100 m.

H Costs for the single lines are based on cables with a design voltage of 12 kV. For each power level the corresponding current was calculated using a power factor of 0,90. The current corresponds to different cable areas and costs. Two cables were chosen for each interval (one for the lowest power level and one for the highest level in the interval). The average of these two costs was used in the table. Power levels below 250 kW and above 25 MW are not relevant for the specific voltage level. Above 6 MW more than one cable is needed. The cost of the material increases linear with the number of cables. The installation cost does not increase linear. An average cost based on the installation cost for one cable was used as a cost for more than one cable.

I Reinforcement costs depends on whether it is the cables or stations that needs reinforcements. Reinforcement cost of cables is in parity with the investment cost for new single lines and depends on power level and cable length. Reinforcement of stations might be possible by replacing the current transformer with a new transformer with a higher power level. The cost for a new transformer, assuming the current station can still be used, is on average 11500 EUR/MW for a 800 kVA or 1250 kVA transformer.

J The cost in EUR/MW of a 10/0.4 kV station depends on the desired power level of the station. A station with a low power level is more expensive per MW than a station with a high power level. In rural areas a lower power level is usually required. This results in a higher cost per MW for stations in rural areas. These assumptions were made: Rural areas: 1x315 kVA station. Suburban areas: 1x800 kVA station. City: 2x1250 kVA station. Costs for other requirements such as embedded/integrated stations are not included. Lower uncertainty bounds for 2020 assumes a reduction of 4,4% of the costs due to more efficient installations and a continued reduction by an additional 4,4% for 2050. No increases in costs are anticipated and upper bounds are set to today's level for both 2020 and 2050.

K The percentage of the investment cost allocated to material cost and installation cost varies widely depending on cable area (power level). When the number och cables in each shaft increases the percentage of the material cost also increases. The average for one cable was used in the table. In more densely populated areas the installation costs increases due to expensive shafts. Lower uncertainty bounds for 2020 assumes a reduction of 17,6% of the investment costs due to more efficient installations and a continued reduction by an additional 10% for 2050.

L The fixed O&M cost are calculated as a standard annual cost of 0,51% of the investment cost. It should be noted that the O&M cost in distribution system is mainly attributed to stations since there is practically no maintenance on cables. The O&M cost is assume to be reduced due to increased efficiency by an annual factor of 1 - 1,8%. Lower uncertainty bounds for 2020 and 2050 corresponds to a continuous annual efficiency increase of 1,8% and upper bounds corresponds to no efficiency increase in O&M.

M Variable O&M cost is in very low for electric transmission systems and considered to be negligible

N Auxiliary electricity consumption can be considered negligible

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5 Sweco, Project data

6 EBR cost database, developed by Swedish bransch organisation Svensk Energi.

7 Swedish Energy Markets Inspectorate (http://ei.se/sv/el/Elnat-och-natprisreglering/de-olika-delarna-i-intaktsramen/)


### Table 3: Electricity distribution, Suburban

| **Technology** | **Electricity Distribution, Suburban** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2020 | 2030 | 2050 | Uncertainty (2020) | | Uncertainty (2050) | | Note | Ref |
| **Energy/technical data** | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines (%) | 3 | 3 | 3 | 3 | 3 | 3 | 2,25 | 3 | A | 1 |
| Energy losses, stations (%) | 1,125 | 1,125 | 1,125 | 1,125 | 0,75 | 1,5 | 0,75 | 1,5 | B | 2 |
| Auxiliary electricity consumption (% of energy delivered) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N | 3 |
| Technical life time (years) | 40 | 40 | 40 | 40 | 35 | 40 | 35 | 50 | C | 4, 5 |
| Typical load profile (-) | 48% | 48% | 48% | 48% | 48% | 48% | 43% | 55% | D | 1, 5 |
| - Residential | 48% | 48% | 48% | 48% | 48% | 48% | 43% | 55% | D | |
| - Commercial | 48% | 48% | 48% | 48% | 48% | 48% | 43% | 55% | D | |
| Construction time (years) | 1 | 1 | 1 | 1 | 1 | 2 | 1 | 2 | | 5 |
| **Financial data** | | | | | | | | | | |
| Distribution network costs (EUR/MWh/year) Suburban | 385 | 385 | 385 | 385 | 347 | 385 | 312 | 487 | E,F | 1, 6 |
| Investment costs; service line, 0 - 20 kW (EUR/unit) | 1436 | 1436 | 1436 | 1436 | 1292 | 1436 | 1163 | 1436 | G,F | 6 |
| Investment costs; service line, 20 - 50 kW (EUR/unit) | 4031 | 4031 | 4031 | 4031 | 3628 | 4031 | 3265 | 4031 | G,F | 6 |
| Investment costs; service line, 50-100 kW (EUR/unit) | 4243 | 4243 | 4243 | 4243 | 3819 | 4243 | 3437 | 4243 | G,F | 6 |
| Investment costs; service line, above 100 kW (EUR/unit) | 9066 | 9066 | 9066 | 9066 | 8159 | 9066 | 7343 | 9066 | G,F | 6 |
| Investment costs; single line, 0-50 kW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Investment costs; single line, 50-250 kW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Investment costs; single line, 100-250 kW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | 6 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Investment costs; single line, 250 kW - 1 MW (EUR/m) | 75 | 75 | 75 | 75 | 65 | 75 | 59 | 75 | H,F | 6 |
| Investment costs; single line, 1 MW - 5 MW (EUR/m) | 80 | 80 | 80 | 80 | 70 | 80 | 63 | 80 | H,F | 6 |
| Investment costs; single line, 5 MW - 25 MW (EUR/m) | 128 | 128 | 128 | 128 | 118 | 128 | 106 | 128 | H,F | 6 |
| Investment costs; single line, 25 MW - 100 MW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Reinforcement costs (EUR/MW) (Station) | 11500 | 11500 | 11500 | 11500 | 10994 | 11500 | 10510 | 11500 | I,F,J | 6 |
| Investment costs; [type 1] station (EUR/MW) | 38000 | 38000 | 38000 | 38000 | 36328 | 38000 | 34730 | 38000 | J | 6 |
| Investment costs; [type 2] station (EUR/MW) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Investments, percentage installation (cables) | 80% | 80% | 80% | 80% | 78% | 80% | 78% | 80% | K | 6 |
| Investments, percentage materials (cables) | 20% | 20% | 20% | 20% | 22% | 20% | 22% | 20% | K | 6 |
| Investments, percentage installation (stations) | 14% | 14% | 14% | 14% | 13% | 14% | 13% | 14% | K | 6 |
| Investments, percentage materials (stations) | 86% | 86% | 86% | 86% | 87% | 86% | 87% | 86% | K | 6 |
| Fixed O&M (EUR/MW/year) | 2681 | 2644 | 2607 | 2570 | 2633 | 2681 | 2539 | 2681 | L | 7 |
| Variable O&M (EUR/MWh) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | M | |

## *Notes*

A The line losses were calculated using reference (1) and the formula Total energy exported to customer / Total energy fed into the system. Lines in rural areas have a higher loss than lines in more populated areas.

B Losses in a transformer tend to decrease with increasing transformer capacity. The losses also depend on the transformer load. When the transformer load decreases under 20 % there is a large increase in the losses. In general the losses are about 1-2 %

C According to the network price regulation from Energimarknadsinspektionen, the technical life time for stations and cables are 40 years. In practice, cable technical life can be shorter, depending on the thermal loading of the cable.

D Calculations for the load profile were based on reference (1). This gave an average value of 44 % for all areas. The load profile is not expected to change to 2020. For 2050 the upper scenario is a smart grid scenario, in which  the load factor remains the same, the lower scenario is an increase in peak load without the use of smart grid leading to a decrease in load factor by 26%.

E The distributions network costs are based on the average station cost and cable cost per customer divided by the average yearly energy transported to a customer. Assumptions on the average cable length per customer and the average number of stations per customer could be translated to a total distribution network cost per customer using the EBR cost database. Cost per MWh are affected both by changes in actual costs and changes in load factors. In 2020 load factors are assumed to be constant. Lower bounds assumes a reduction of 10% of the costs due to more efficient installations, no cost increased is assumed. For 2050 the lower bounds corresponds to a smart grid scenario with power factor increased by 15% in combination with a continued 10% cost decrease due to increased efficiency. The upper bound corresponds to a scenario where peak loads are increased by 15%, leading to reduced power factors and increased cost per MWh.

F Price projections are based on an extrapolation of price development over the years 2000 - 2014 corrected for inflation. Over the six last years the prices have stabilized on a constant level and it is assumed that prices will remain stable. Lower uncertainty bounds for 2020 assumes a reduction of 10% of the costs due to more efficient installations and a continued reduction by an additional 10% for 2050. No increases in costs are anticipated and upper bounds are set to today's level for both 2020 and 2050.

G Costs for service lines are based on cables with a design voltage of 0,4 kV. For each power level the corresponding current was calculated using a power factor of 0,90. The current corresponds to different cable areas and costs. Two cables were chosen for each interval (one for the lowest power level and one for the highest level in the interval). The average of these two costs was used in the table. The service line length was bases on the guidelines: 0-20 kW - 20 m, 20-100 kW - 50 m, Above 100 kW -100 m.

H Costs for the single lines are based on cables with a design voltage of 12 kV. For each power level the corresponding current was calculated using a power factor of 0,90. The current corresponds to different cable areas and costs. Two cables were chosen for each interval (one for the lowest power level and one for the highest level in the interval). The average of these two costs was used in the table. Power levels below 250 kW and above 25 MW are not relevant for the specific voltage level. Above 6 MW more than one cable is needed. The cost of the material increases linear with the number of cables. The installation cost does not increase linear. An average cost based on the installation cost for one cable was used as a cost for more than one cable.

I Reinforcement costs depends on whether it is the cables or stations that needs reinforcements. Reinforcement cost of cables is in parity with the investment cost for new single lines and depends on power level and cable length. Reinforcement of stations might be possible by replacing the current transformer with a new transformer with a higher power level. The cost for a new transformer, assuming the current station can still be used, is on average 11500 EUR/MW for a 800 kVA or 1250 kVA transformer.

J The cost in EUR/MW of a 10/0.4 kV station depends on the desired power level of the station. A station with a low power level is more expensive per MW than a station with a high power level. In rural areas a lower power level is usually required. This results in a higher cost per MW for stations in rural areas. These assumptions were made: Rural areas: 1x315 kVA station. Suburban areas: 1x800 kVA station. City: 2x1250 kVA station. Costs for other requirements such as embedded/integrated stations are not included. Lower uncertainty is if Danish salaries decrease to the Swedish level (a decrease by 17,6 %). Upper level is if costs stay on today’s level. For 2050 better efficiency is expected which is estimated to decrease the cost by an additional 10 %.

K The percentage of the investment cost allocated to material cost and installation cost varies widely depending on cable area (power level). When the number och cables in each shaft increases the percentage of the material cost also increases. The average for one cable was used in the table. In more densely populated areas the installation costs increases due to expensive shafts. Lower uncertainty is if Danish salaries decrease to the Swedish level (a decrease by 17,6 %), this will decrease the installation costs.

L The fixed O&M cost are calculated as a standard annual cost of 0,51% of the investment cost. It should be noted that the O&M cost in distribution system is mainly attributed to stations since there is practically no maintenance on cables. The O&M cost is assume to be reduced due to increased efficiency by an annual factor of 1 - 1,8%. Lower uncertainty bounds for 2020 and 2050 corresponds to a continuous annual efficiency increase of 1,8% and upper bounds corresponds to no efficiency increase in O&M.

M Variable O&M cost is in very low for electric transmission systems and considered to be negligible

N Auxiliary electricity consumption can be considered negligible

### *References*


1 Särskilda rapporten - teknisk data from Energimarknadsinspektionen (Statistics from Swedish utility companies) from 2014 (http://www.ei.se/sv/Publikationer/Arsrapporter/)

2 The Scope for Energy Saving in the EU through the Use of Energy-Efficient Electricity Distribution Transformers. H. De Keukeabaer, D. Chapman, S. Fassbinder, M. McDermott, (2001).

3 International Electrotechnical Comission, Efficient Electrical Energy Transmission and Distribution (http://www.iec.ch/about/brochures/pdf/technology/transmission.pdf)

4 Energimarknadsinspektionens föreskrifter om intäktsramar för elnätsföretag. http://ei.se/Documents/Publikationer/rapporter_och_pm/Rapporter%202015/Ei_R2015_01.pdf

5 Sweco, Project data

6 EBR cost database, developed by Swedish bransch organisation Svensk Energi.

7 Swedish Energy Markets Inspectorate (http://ei.se/sv/el/Elnat-och-natprisreglering/de-olika-delarna-i-intaktsramen/)


### Table 4: Electricity distribution, city

| **Technology** | **Energy Transport Electricity Distribution, City** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2020 | 2030 | 2050 | Uncertainty (2020) | | Uncertainty (2050) | | Note | Ref |
| **Energy/technical data** | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines (%) | 2,25 | 2,25 | 2,25 | 2,25 | 2,25 | 2,25 | 1,5 | 2,25 | A | 1 |
| Energy losses, stations (%) | 1,13 | 1,13 | 1,13 | 1,13 | 0,75 | 1,5 | 0,75 | 1,5 | B | 2 |
| Auxiliary electricity consumption (% of energy delivered) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N | 3 |
| Technical life time (years) | 40 | 40 | 40 | 40 | 35 | 40 | 35 | 50 | C | 4, 5 |
| Typical load profile (-) | 50% | 50% | 50% | 50% | 50% | 50% | 45% | 58% | D | 1, 5 |
| - Residential | 50% | 50% | 50% | 50% | 50% | 50% | 45% | 58% | D | |
| - Commercial | 50% | 50% | 50% | 50% | 50% | 50% | 45% | 58% | D | |
| Construction time (years) | 1 | 1 | 1 | 1 | 1 | 2 | 1 | 2 | | 5 |
| | | | | | | | | | | |
| **Financial data** | | | | | | | | | | |
| Distribution network costs (EUR/MWh/year) City | 365 | 365 | 365 | 365 | 329 | 365 | 278 | 442 | E,F | 1, 6 |
| Investment costs; service line, 0 - 20 kW (EUR/unit) | 2149 | 2149 | 2149 | 2149 | 1934 | 2149 | 1741 | 2149 | G,F | 6 |
| Investment costs; service line, 20 - 50 kW (EUR/unit) | 5618 | 5618 | 5618 | 5618 | 5056 | 5618 | 4551 | 5618 | G,F | 6 |
| Investment costs; service line, 50-100 kW (EUR/unit) | 5774 | 5774 | 5774 | 5774 | 5197 | 5774 | 4677 | 5774 | G,F | 6 |
| Investment costs; service line, above 100 kW (EUR/unit) | 12131 | 12131 | 12131 | 12131 | 10918 | 12131 | 9826 | 12131 | G,F | 6 |
| Investment costs; single line, 0-50 kW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Investment costs; single line, 50-250 kW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Investment costs; single line, 100-250 kW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | 6 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Investment costs; single line, 250 kW - 1 MW (EUR/m) | 115 | 115 | 115 | 115 | 100 | 115 | 90 | 115 | H,F | 6 |
| Investment costs; single line, 1 MW - 5 MW (EUR/m) | 120 | 120 | 120 | 120 | 104 | 120 | 94 | 120 | H,F | 6 |
| Investment costs; single line, 5 MW - 25 MW (EUR/m) | 169 | 169 | 169 | 169 | 154 | 169 | 139 | 169 | H,F | 6 |
| Investment costs; single line, 25 MW - 100 MW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Reinforcement costs (EUR/MW) (Station) | 11500 | 11500 | 11500 | 11500 | 10994 | 11500 | 10510 | 11500 | I,F,J | 6 |
| Investment costs; [type 1] station (EUR/MW) | 38000 | 38000 | 38000 | 38000 | 36328 | 38000 | 34730 | 38000 | J | 6 |
| Investment costs; [type 2] station (EUR/MW) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Investments, percentage installation (cables) | 86% | 86% | 86% | 86% | N/A | N/A | N/A | N/A | K | 6 |
| Investments, percentage materials (cables) | 14% | 14% | 14% | 14% | N/A | N/A | N/A | N/A | K | 6 |
| Investments, percentage installation (stations) | 5% | 5% | 5% | 5% | 4% | 5% | 4% | 5% | K | 6 |
| Investments, percentage materials (stations) | 95% | 95% | 95% | 95% | 96% | 95% | 96% | 95% | K | 6 |
| Fixed O&M (EUR/MW/year) | 2866 | 2826 | 2786 | 2747 | 2814 | 2866 | 2714 | 2866 | L | 7 |
| Variable O&M (EUR/MWh) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | M | |

## *Notes*

A The line losses were calculated using reference (1) and the formula Total energy exported to customer / Total energy fed into the system. Lines in rural areas have a higher loss than lines in more populated areas.

B Losses in a transformer tend to decrease with increasing transformer capacity. The losses also depend on the transformer load. When the transformer load decreases under 20 % there is a large increase in the losses. In general the losses are about 1-2 %

C According to the network price regulation from Energimarknadsinspektionen, the technical life time for stations and cables are 40 years. In practice, cable technical life can be shorter, depending on the thermal loading of the cable.

D Calculations for the load profile were based on reference (1). This gave an average value of 44 % for all areas. The load profile is not expected to change to 2020. For 2050 the upper scenario is a smart grid scenario, in which the load factor is increased by 6 %, the lower scenario is an increase in peak load without the use of smart grid leading to a decrease in load factor by 21%.

E The distributions network costs are based on the average station cost and cable cost per customer divided by the average yearly energy transported to a customer. Assumptions on the average cable length per customer and the average number of stations per customer could be translated to a total distribution network cost per customer using the EBR cost database. Cost per MWh are affected both by changes in actual costs and changes in load factors. In 2020 load factors are assumed to be constant. Lower bounds assume a reduction of 10% of the costs due to more efficient installations, no cost increased is assumed. For 2050 the lower bounds corresponds to a smart grid scenario with power factor increased by 15% in combination with a continued 10% cost decrease due to increased efficiency. The upper bound corresponds to a scenario where peak loads are increased by 15%, leading to reduced power factors and increased cost per MWh.

F Price projections are based on an extrapolation of price development over the years 2000 - 2014 corrected for inflation. Over the six last years the prices have stabilized on a constant level and it is assumed that prices will remain stable. Lower uncertainty bounds for 2020 assumes a reduction of 10% of the costs due to more efficient installations and a continued reduction by an additional 10% for 2050. No increases in costs are anticipated and upper bounds are set to today's level for both 2020 and 2050.

G Costs for service lines are based on cables with a design voltage of 0,4 kV. For each power level the corresponding current was calculated using a power factor of 0,90. The current corresponds to different cable areas and costs. Two cables were chosen for each interval (one for the lowest power level and one for the highest level in the interval). The average of these two costs was used in the table. The service line length was bases on the guidelines: 0-20 kW - 20 m, 20-100 kW - 50 m, Above 100 kW -100 m.

H Costs for the single lines are based on cables with a design voltage of 12 kV. For each power level the corresponding current was calculated using a power factor of 0,90. The current corresponds to different cable areas and costs. Two cables were chosen for each interval (one for the lowest power level and one for the highest level in the interval). The average of these two costs was used in the table. Power levels below 250 kW and above 25 MW are not relevant for the specific voltage level. Above 6 MW more than one cable is needed. The cost of the material increases linear with the number of cables. The installation cost does not increase linear. An average cost based on the installation cost for one cable was used as a cost for more than one cable.

I Reinforcement costs depends on whether it is the cables or stations that needs reinforcements. Reinforcement cost of cables is in parity with the investment cost for new single lines and depends on power level and cable length. Reinforcement of stations might be possible by replacering the current transformer with a new transformer with a higher power level. The cost for a new transformer, assuming the current station can still be used, is on average 11500 EUR/MW for a 800 kVA or 1250 kVA transformer.

J The cost in EUR/MW of a 10/0.4 kV station depends on the desired power level of the station. A station with a low power level is more expensive per MW than a station with a high power level. In rural areas a lower power level is usually required. This results in a higher cost per MW for stations in rural areas. These assumptions were made: Rural areas: 1x315 kVA station. Suburban areas: 1x800 kVA station. City: 2x1250 kVA station. Costs for other requirements such as embedded/integrated stations are not included. Lower uncertainty is if Danish salaries decrease to the Swedish level (a decrease by 17,6 %). Upper level is if costs stay on today’s level. For 2050 better efficiency is expected which is estimated to decrease the cost by an additional 10 %.

K The percentage of the investment cost allocated to material cost and installation cost varies widely depending on cable area (power level). When the number och cables in each shaft increases the percentage of the material cost also increases. The average for one cable was used in the table. In more densely populated areas the installation costs increases due to expensive shafts. Lower uncertainty is if Danish salaries decrease to the Swedish level (a decrease by 17,6 %), this will decrease the installation costs.

L The fixed O&M cost are calculated as a standard annual cost of 0,51% of the investment cost. It should be noted that the O&M cost in distribution system is mainly attributed to stations since there is practically no maintenance on cables. The O&M cost is assume to be reduced due to increased efficiency by an annual factor of 1 - 1,8%. Lower uncertainty bounds for 2020 and 2050 corresponds to a continuous annual efficiency increase of 1,8% and upper bounds corresponds to no efficiency increase in O&M.

M Variable O&M cost is in very low for electric transmission systems and considered to be negligible

N Auxiliary electricity consumption can be considered negligible

## *References*

1 Särskilda rapporten - teknisk data from Energimarknadsinspektionen (Statistics from Swedish utility companies) from 2014 (http://www.ei.se/sv/Publikationer/Arsrapporter/)

2 The Scope for Energy Saving in the EU through the Use of Energy-Efficient Electricity Distribution Transformers. H. De Keukeabaer, D. Chapman, S. Fassbinder, M. McDermott, (2001).

3 International Electrotechnical Comission, Efficient Electrical Energy Transmission and Distribution (http://www.iec.ch/about/brochures/pdf/technology/transmission.pdf)

4 Energimarknadsinspektionens föreskrifter om intäktsramar för elnätsföretag. http://ei.se/Documents/Publikationer/rapporter_och_pm/Rapporter%202015/Ei_R2015_01.pdf

5 Sweco, Project data

6 EBR cost database, developed by Swedish bransch organisation Svensk Energi.

7 Swedish Energy Markets Inspectorate (http://ei.se/sv/el/Elnat-och-natprisreglering/de-olika-delarna-i-intaktsramen/)

## Table 5: Electricity distribution, New developed area

| Technology | Electricity Distribution, New developed areas | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2020 | 2030 | 2050 | Uncertainty (2020) | | Uncertainty (2050) | | Note | Ref |
| **Energy/technical data** | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines (%) | 3 | 3 | 3 | 3 | 2,25 | 3 | 2,25 | 3 | A | 1 |
| Energy losses, stations (%) | 1,1 | 1,1 | 1,1 | 1,1 | 0,75 | 1,5 | 0,75 | 1,5 | B | 2 |
| Auxiliary electricity consumption (% of energy delivered) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N | 3 |
| Technical life time (years) | 40 | 40 | 40 | 40 | 35 | 40 | 35 | 50 | C | 4, 5 |
| Typical load profile (-) | 48% | 48% | 48% | 48% | 48% | 48% | 43% | 55% | D | 1, 5 |
| - Residential | 48% | 48% | 48% | 48% | 48% | 48% | 43% | 55% | D | |
| - Commercial | 48% | 48% | 48% | 48% | 48% | 48% | 43% | 55% | D | |
| Construction time (years) | 1 | 1 | 1 | 1 | 1 | 2 | 1 | 2 | | 5 |
| **Financial data** | | | | | | | | | | |
| Distribution network costs (EUR/MWh/year) New developed area | 173 | 173 | 173 | 173 | 156 | 173 | 132 | 206 | E,F | 1, 6 |
| Investment costs; service line, 0 - 20 kW (EUR/unit) | 524 | 524 | 524 | 524 | 472 | 524 | 424 | 524 | G,F | 6 |
| Investment costs; service line, 20 - 50 kW (EUR/unit) | 1412 | 1412 | 1412 | 1412 | 1271 | 1412 | 1144 | 1412 | G,F | 6 |
| Investment costs; service line, 50-100 kW (EUR/unit) | 1583 | 1583 | 1583 | 1583 | 1425 | 1583 | 1282 | 1583 | G,F | 6 |
| Investment costs; service line, above 100 kW (EUR/unit) | 3745 | 3745 | 3745 | 3745 | 3371 | 3745 | 3033 | 3745 | G,F | 6 |
| Investment costs; single line, 0-50 kW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Investment costs; single line, 50-250 kW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Investment costs; single line, 100-250 kW (EUR/m) | 36 | 36 | 36 | 36 | 32 | 36 | 29 | 36 | H,F | 6 |
| Investment costs; single line, 250 kW - 1 MW (EUR/m) | 36 | 36 | 36 | 36 | 32 | 36 | 29 | 36 | H,F | 6 |
| Investment costs; single line, 1 MW - 5 MW (EUR/m) | 41 | 41 | 41 | 41 | 37 | 41 | 33 | 41 | H,F | 6 |
| Investment costs; single line, 5 MW - 25 MW (EUR/m) | 88 | 88 | 88 | 88 | 85 | 88 | 77 | 88 | H,F | 6 |
| Investment costs; single line, 25 MW - 100 MW (EUR/m) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | H,F | |
| Reinforcement costs (EUR/MW) (Station) | 11500 | 11500 | 11500 | 11500 | 10994 | 11500 | 10510 | 11500 | I,F,J | 6 |
| Investment costs; [type 1] station (EUR/MW) | 38000 | 38000 | 38000 | 38000 | 36328 | 38000 | 34730 | 38000 | J | 6 |
| Investment costs; [type 2] station (EUR/MW) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Investments, percentage installation (cables) | 80% | 80% | 80% | 80% | 78% | 80% | 78% | 80% | K | 6 |
| Investments, percentage materials (cables) | 20% | 20% | 20% | 20% | 22% | 20% | 22% | 20% | K | 6 |
| Investments, percentage installation (stations) | 14% | 14% | 14% | 14% | 13% | 14% | 13% | 14% | K | 6 |
| Investments, percentage materials (stations) | 86% | 86% | 86% | 86% | 87% | 86% | 87% | 86% | K | 6 |
| Fixed O&M (EUR/MW/year) | 1358 | 1339 | 1321 | 1302 | 1334 | 1358 | 1286 | 1358 | L | 7 |
| Variable O&M (EUR/MWh) | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | M | |

*Notes*

A The line losses were calculated using reference (1) and the formula Total energy exported to customer / Total energy fed into the system. Lines in rural areas have a higher loss than lines in more populated areas.

B Losses in a transformer tend to decrease with increasing transformer capacity. The losses also depend on the transformer load. When the transformer load decreases under 20 % there is a large increase in the losses. In general the losses are about 1-2 %

C According to the network price regulation from Energimarknadsinspektionen, the technical life time for stations and cables are 40 years. In practice, cable technical life can be shorter, depending on the thermal loading of the cable.

D Calculations for the load profile were based on reference (1). This gave an average value of 48 % for all areas. The load profile is not expected to change to 2020. For 2050 the upper scenario is a smart grid scenario, in which the load factor increases by 10 %, the lower scenario is an increase in peak load of 15 % without the use of smart grid leading to a corresponding decrease in load factor.

E The distributions network costs are based on the average station cost and cable cost per customer divided by the average yearly energy transported to a customer. Assumptions on the average cable length per customer and the average number of stations per customer could be translated to a total distribution network cost per customer using the EBR cost database. Costs per MWh are affected both by changes in actual costs and changes in load factors. In 2020 load factors are assumed to be constant. Lower bounds assume a reduction of 10% of the costs due to more efficient installations, no cost increased is assumed. For 2050 the lower bounds corresponds to a smart grid scenario with power factor increased by 15% in combination with a continued 10% cost decrease due to increased efficiency. The upper bound corresponds to a scenario where peak loads are increased by 15%, leading to reduced power factors and increased cost per MWh.

F Price projections are based on an extrapolation of price development over the years 2000 - 2014 corrected for inflation. Over the six last years the prices have stabilized on a constant level and it is assumed that prices will remain stable. Lower uncertainty bounds for 2020 assumes a reduction of 10% of the costs due to more efficient installations and a continued reduction by an additional 10% for 2050. No increases in costs are anticipated and upper bounds are set to today's level for both 2020 and 2050.

G Costs for service lines are based on cables with a design voltage of 0,4 kV. For each power level the corresponding current was calculated using a power factor of 0,90. The current corresponds to different cable areas and costs. Two cables were chosen for each interval (one for the lowest power level and one for the highest level in the interval). The average of these two costs was used in the table. The service line length was bases on the guidelines: 0-20 kW - 20 m, 20-100 kW - 50 m, Above 100 kW -100 m.

H Costs for the single lines are based on cables with a design voltage of 12 kV. For each power level the corresponding current was calculated using a power factor of 0,90. The current corresponds to different cable areas and costs. Two cables were chosen for each interval (one for the lowest power level and one for the highest level in the interval). The average of these two costs was used in the table. Power levels below 250 kW and above 25 MW are not relevant for the specific voltage level. Above 6 MW more than one cable is needed. The cost of the material increases linear with the number of cables. The installation cost does not increase linear. An average cost based on the installation cost for one cable was used as a cost for more than one cable.

I Reinforcement costs depends on whether it is the cables or stations that needs reinforcements. Reinforcement cost of cables is in parity with the investment cost for new single lines and depends on power level and cable length. Reinforcement of stations might be possible by replacing the current transformer with a new transformer with a higher power level. The cost for a new transformer, assuming the current station can still be used, is on average 11500 EUR/MW for a 800 kVA or 1250 kVA transformer.

J The cost in EUR/MW of a 10/0.4 kV station depends on the desired power level of the station. A station with a low power level is more expensive per MW than a station with a high power level. In rural areas a lower power level is usually required. This results in a higher cost per MW for stations in rural areas. These assumptions were made: Rural areas: 1x315 kVA station. Suburban areas: 1x800 kVA station. City: 2x1250 kVA station. Costs for other requirements such as embedded/integrated stations are not included. Lower uncertainty is if Danish salaries decrease to the Swedish level (a decrease by 17,6 %). Upper level is if costs stay on today's level. For 2050 better efficiency is expected which is estimated to decrease the cost by an additional 10 %.

K The percentage of the investment cost allocated to material cost and installation cost varies widely depending on cable area (power level). When the number och cables in each shaft increases the percentage of the material cost also increases. The average for one cable was used in the table. In more densely populated areas the installation costs increases due to expensive shafts. Lower uncertainty is if Danish salaries decrease to the Swedish level (a decrease by 17,6 %), this will decrease the installation costs.

L The fixed O&M cost are calculated as a standard annual cost of 0,51% of the investment cost. It should be noted that the O&M cost in distribution system is mainly attributed to stations since there is practically no maintenance on cables. The O&M cost is assume to be reduced due to increased efficiency by an annual factor of 1 - 1,8%. Lower uncertainty bounds for 2020 and 2050 corresponds to a continuous annual efficiency increase of 1,8% and upper bounds corresponds to no efficiency increase in O&M.

M Variable O&M cost is in very low for electric transmission systems and considered to be negligible

N Auxiliary electricity consumption can be considered negligible

## *References*

1 Särskilda rapporten - teknisk data from Energimarknadsinspektionen (Statistics from Swedish utility companies) from 2014 (http://www.ei.se/sv/Publikationer/Arsrapporter/)

2 The Scope for Energy Saving in the EU through the Use of Energy-Efficient Electricity Distribution Transformers. H. De Keukeabaer, D. Chapman, S. Fassbinder, M. McDermott, (2001).

3 International Electrotechnical Comission, Efficient Electrical Energy Transmission and Distribution (http://www.iec.ch/about/brochures/pdf/technology/transmission.pdf)

4 Energimarknadsinspektionens föreskrifter om intäktsramar för elnätsföretag. http://ei.se/Documents/Publikationer/rapporter_och_pm/Rapporter%202015/Ei_R2015_01.pdf

5 Sweco, Project data

6 EBR cost database, developed by Swedish bransch organisation Svensk Energi.

7 Swedish Energy Markets Inspectorate (http://ei.se/sv/el/Elnat-och-natprisreglering/de-olika-delarna-i-intaktsramen/)

# 112 Natural gas distribution grid

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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.

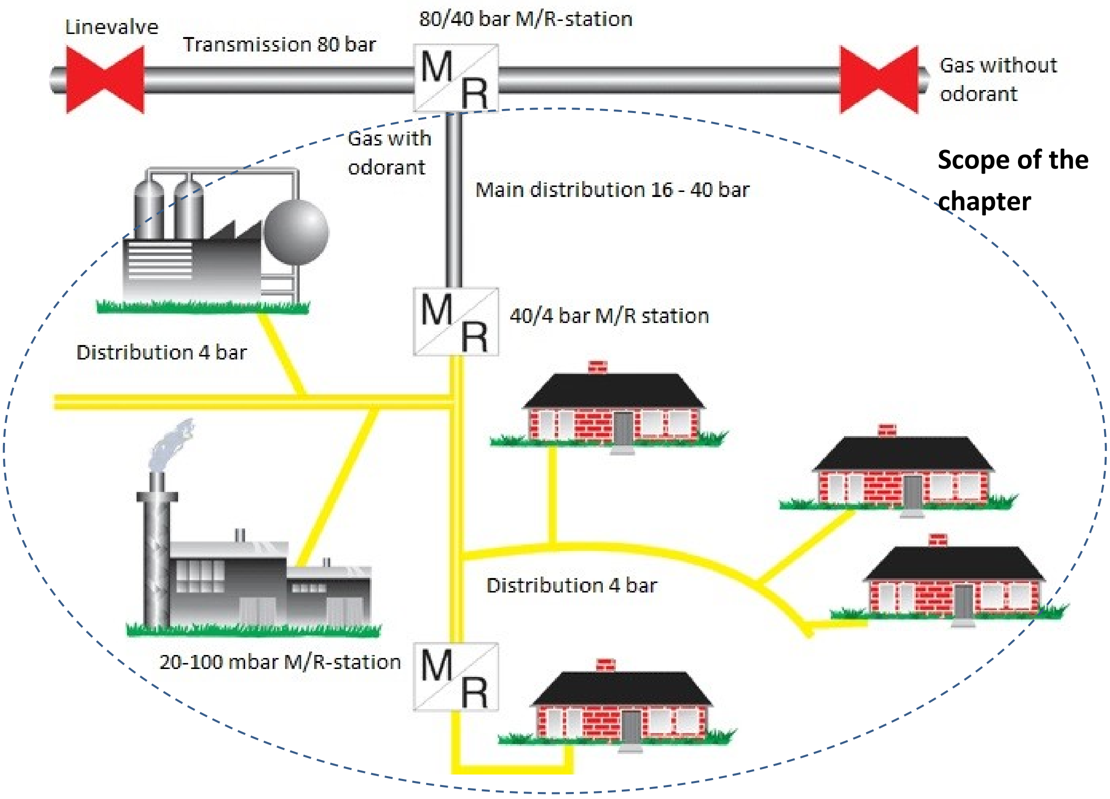


Figure 1 Overview of the gas network. Based on ref. [1].

**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.

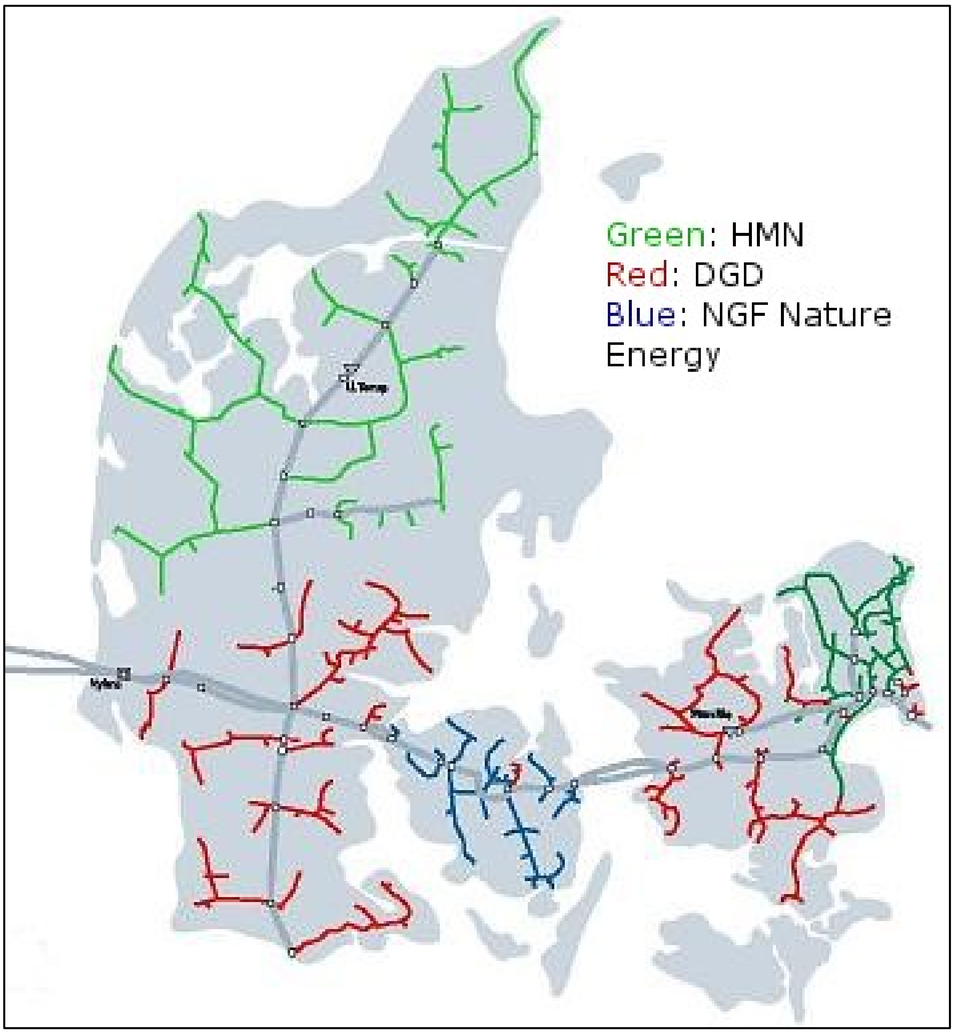


**Figure 2 Geographical extent of the Danish transmission network (grey) and the main distribution network (green, red & blue). The colours refer to the companies operating the system.**

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.

### References

[1] www.naturgasfakta.dk
[2] www.gasmarked.dk
[3] Dansk Gas Distribution
[4] NGF Nature Energy
[5] HMN Gasnet
[6] Energinet
[7] DGC
[8] "Biogas upgrading - Technology review", published by Energiforsk 2016. ISBN 978-91-7673-275-5.

## Data sheets

### Table 6: Natural gas main distribution line

| Technology | Energy Transport, Natural Gas Main distribution line | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2020 | 2030 | 2050 | Uncertainty (2020) | | Uncertainty (2050) | | Note | Ref |
| **Energy/technical data** | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines 1-20 MW (%) | 0,1 | 0,1 | 0,1 | 0,1 | 0,01 | 0,15 | 0,01 | 0,15 | A | 1 |
| Energy losses, lines 20-100 MW (%) | 0,1 | 0,1 | 0,1 | 0,1 | 0,01 | 0,15 | 0,01 | 0,15 | A | |
| Energy losses, lines above 100 MW (%) | 0,1 | 0,1 | 0,1 | 0,1 | 0,01 | 0,15 | 0,01 | 0,15 | A | |
| Energy losses, stations [Type 1] (%) | - | - | - | - | - | - | - | - | B | |
| Energy losses, stations [Type 2] (%) | 0,10 | 0,10 | 0,10 | 0,10 | 0 | 0,12 | 0 | 0,12 | C | 2 |
| Auxiliary electricity consumption (% energy transmitted) | 0,005 | 0,005 | 0,005 | 0,005 | 0,004 | 0,006 | 0,004 | 0,006 | | 2 |
| Technical life time (years) | 50 | 50 | 50 | 50 | 50 | 80 | 50 | 80 | | 2 |
| Typical load profile (-) | 0,2 | 0,2 | 0,2 | 0,2 | 0,05 | 0,4 | 0,05 | 0,4 | | 2 |
| Construction time (years) | 1 | 1 | 1 | 1 | 0,7 | 1,5 | 0,7 | 1,5 | D | 2 |
| **Financial data** | | | | | | | | | | |
| **Investment costs** | | | | | | | | | | |
| Investment costs; single line, 0 - 50 MW (EUR/MW/m) | 11 | 11 | 11 | 11 | 9 | 13 | 9 | 13 | E, F | 2 |
| Investment costs; single line, 50-100 MW (EUR/MW/m) | 4,2 | 4 | 4 | 4 | 3,4 | 5,0 | 3,4 | 5,0 | E, G | 2 |
| Investment costs; single line, 100 - 250 MW (EUR/MW/m) | 2,2 | 2 | 2 | 2 | 1,8 | 2,7 | 1,8 | 2,7 | E, G | 2 |
| Investment costs; single line, 250-500 MW (EUR/MW/m) | 1,2 | 1 | 1 | 1 | 0,9 | 1,4 | 0,9 | 1,4 | E, G | 2 |
| Investment costs; single line, 500-1000 MW (EUR/MW/m) | 0,7 | 1 | 1 | 1 | 0,5 | 0,8 | 0,5 | 0,8 | E, G | 1 |
| Investment costs; single line, above 1000 MW (EUR/MW/m) | - | - | - | - | - | - | - | - | i | |
| Reinforcement costs (EUR/MW) | - | - | - | - | - | - | - | - | H | |
| Investment costs; [type 1] station (EUR/MW) | - | - | - | - | - | - | - | - | B, J | |
| Investment costs; [type 2] station (EUR/MW) | 27000 | 27000 | 27000 | 27000 | 7000 | 45000 | 0 | 0 | C, K | 2 |
| Investments, percentage installation | 75 | 75 | 75 | 75 | 65 | 85 | 65 | 85 | | 2 |
| Investments, percentage materials | 25 | 25 | 25 | 25 | 15 | 35 | 15 | 35 | | 2 |
| Fixed O&M (EUR/MW/km/year) | 0,12 | 0,12 | 0,12 | 0,12 | 0,10 | 0,15 | 0,10 | 0,15 | | 2 |
| Variable O&M (EUR/MWh/km) | 1,1E-05 | 1,1E-05 | 1,1E-05 | 1,1E-05 | 9,0E-06 | 1,4E-05 | 9,0E-06 | 1,4E-05 | | 2 |

## *Notes*

A There are no general data available for the Danish gas system. The stated losses are based on a European survey that includes all parts in level 2 of the transmission, including stations. It is assumed that the losses (given as kg/km) are the same for transmission level 1 and 2. European gas networks are generally older than the Danish system. Therefore, it is expected that the losses from the Danish system are significantly lower than stated in the table. The lack of data explains the high uncertainty stated.

B Type 1 MR stations supplying the transmission system level 2 - not part of the scope

C Type 2 MR stations supplying the 4 bar distribution system. The stated number represents the gas consumption for preheating before expansion from 40 to 4 bar. Expansion from 19 or 16 bar to 4 bar doesn't require preheating. Losses are included in the number stated for lines, see note A.

D Includes engineering, tender, and construction.

E Rates include VVM review, landowner compensation and archaeological screening. Based on 20 km, of which 8 % is based on drilling.

F Data given is for a 50 MW capacity

G Two pipes were chosen for each interval (one for the lowest power level and one for the highest). The average of these two are stated in the table.

H Not possible to give general numbers. Depends on kind of reinforcement. Can be calculated based on the other numbers given.

I Capacity not relevant - too high

J Type 1 MR stations supplying the transmission system level 2 - not part of the scope

K Type 1 MR stations supplying the transmission system level 2 .The stated costs are the average cost for a 40/4 bar MR station where reheating after expansion is required and a 19/4 bar MR station where reheating is not necessary. The cost is only modestly size dependent. A 40/4 bar station capacity of 10.000 m3/h is 20 % higher than a similar station with a capacity of 5.000 m3/h.

## *References*

1 Survey methane emissions for gas transmission and distribution in Europe Marcogaz WG-ME-14-26 29/02/2016

2 HMN Naturgas

## Table 7: Gas Distribution, rural

| Technology | Natural Gas Distribution, rural areas | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2020 | 2030 | 2050 | Uncertainty (2020) | | Uncertainty (2050) | | Note | Ref |
| **Energy/technical data** | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines (%) | 0,26 | 0,26 | 0,26 | 0,26 | 0,05 | 0,3 | 0,05 | 0,3 | A | 1 |
| Energy losses, stations (%) | - | - | - | - | - | - | - | - | B | |
| Auxiliary electricity consumption (% of energy delivered) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | C | |
| Technical life time (years) | 50 | 50 | 50 | 50 | 50 | 80 | 50 | 80 | | 2 |
| Typical load profile (-) | | | | | | | | | D | |
| - Residential | 0,2 | 0,2 | 0,2 | 0,2 | 0,15 | 0,25 | 0,15 | 0,25 | D | |
| - Commercial | N/A | N/A | N/A | N/A | | | | | D | |
| Construction time (years) | 0,4 | 0,4 | 0,4 | 0,4 | 0,3 | 0,5 | 0,3 | 0,5 | | 2 |
| | | | | | | | | | | |
| **Financial data** | | | | | | | | | | |
| Distribution network costs (EUR/MWh/year) Rural | 140 | 140 | 140 | 140 | 130 | 150 | 130 | 150 | | 2 |
| Investment costs; service line, 0 - 20 kW (EUR/unit) | 1600 | 1600 | 1600 | 1600 | 1400 | 1800 | 1400 | 1800 | | 2 |
| Investment costs; service line, 20 - 50 kW (EUR/unit) | - | - | - | - | - | - | - | - | E | |
| Investment costs; service line, 50-100 kW (EUR/unit) | - | - | - | - | - | - | - | - | E | |
| Investment costs; service line, above 100 kW (EUR/unit) | - | - | - | - | - | - | - | - | E | |
| Investment costs; single line, 0-50 kW (EUR/m) | 50 | 50 | 50 | 50 | 45 | 55 | 45 | 55 | F | |
| Investment costs; single line, 50-250 kW (EUR/m) | **50** | 50 | 50 | 50 | 45 | 55 | 45 | 55 | F | |
| Investment costs; single line, 100-250 kW (EUR/m) | 50 | 50 | 50 | 50 | 45 | 55 | 45 | 55 | F | |
| Investment costs; single line, 250 kW - 1 MW (EUR/m) | 50 | 50 | 50 | 50 | 45 | 55 | 45 | 55 | F | |
| Investment costs; single line, 1 MW - 5 MW (EUR/m) | 53 | 53 | 53 | 53 | 48 | 59 | 48 | 59 | G | |
| Investment costs; single line, 5 MW - 25 MW (EUR/m) | 68 | 68 | 68 | 68 | 62 | 75 | 62 | 75 | G | |
| Investment costs; single line, 25 MW - 100 MW (EUR/m) | - | - | - | - | - | - | - | - | | |
| Reinforcement costs (EUR/MW) | - | - | - | - | - | - | - | - | H | |
| Type 1 station (EUR/MW) | - | - | - | - | - | - | - | - | I | |
| Type 2 station (EUR/MW) | - | - | - | - | - | - | - | - | I | |
| Investments, percentage installation | 80% | 80% | 80% | 80% | 70% | 90% | 70% | 90% | | 2 |
| Investments, percentage materials | 20% | 20% | 20% | 20% | 10% | 30% | 10% | 30% | | 2 |
| Fixed O&M (EUR/MW/year) | 750 | 750 | 750 | 750 | 600 | 900 | 600 | 900 | | 2 |
| Variable O&M (EUR/MWh) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 2 |

## *Notes*

A There are no general data available for the Danish gas system. The stated losses are based on a European survey. European gas networks are generally older than the Danish system. Therefore, it is expected the losses from the Danish system are significantly lower than stated in the table. The lack of data explains the high uncertainty stated.

B As mentioned in the qualitative description, new gas systems will be constructed without stations in the distribution network

C There is no power consuming parts in the distribution system consumption for preheating before expansion from 40 to 4 bar. Expansion from 19 or 16 bar to 4 bar doesn't require preheating. Losses are included in the number stated for lines, see note A.

D Based on given case

E Capacity range not relevant for given case

F Stated number is for Ø40 pipes - the smallest pipe applied. It is only marginally cheaper to apply smaller pipes.

G Two pipes were chosen for each interval (one for the lowest power level and one for the highest). The average of these two is stated in the table.

H Reinforcement not relevant

I No station will be installed for the distribution network

## *References*

1 Survey methane emissions for gas transmission and distribution in Europe Marcogaz WG-ME-14-26 29/02/2016

2 HMN Naturgas

## Table 8: Gas distribution, suburban

| Technology | Natural Gas Distribution, suburban areas | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2020 | 2030 | 2050 | Uncertainty (2020) | | Uncertainty (2050) | | Note | Ref |
| **Energy/technical data** | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines (%) | 0,26 | 0,26 | 0,26 | 0,26 | 0,05 | 0,3 | 0,05 | 0,3 | A | 1 |
| Energy losses, stations (%) | - | - | - | - | - | - | - | - | B | |
| Auxiliary electricity consumption (% of energy delivered) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | C | |
| Technical life time (years) | 50 | 50 | 50 | 50 | 50 | 80 | 50 | 80 | | 2 |
| Typical load profile (-) | - | - | - | - | - | - | - | - | | |
| - Residential | 0,2 | 0,2 | 0,2 | 0,2 | 0,15 | 0,25 | 0,15 | 0,25 | D | |
| - Commercial | N/A | N/A | N/A | N/A | | | | | D | |
| Construction time (years) | 0,4 | 0,4 | 0,4 | 0,4 | 0,3 | 0,5 | 0,3 | 0,5 | | 2 |
| | | | | | | | | | | |
| **Financial data** | | | | | | | | | | |
| Distribution network costs (EUR/MWh/year) Suburban | 150 | 150 | 150 | 150 | 140 | 170 | 140 | 170 | | 2 |
| Investment costs; service line, 0 - 20 kW (EUR/unit) | 1600 | 1600 | 1600 | 1600 | 1400 | 1800 | 1400 | 1800 | | 2 |
| Investment costs; service line, 20 - 50 kW (EUR/unit) | - | - | - | - | - | - | - | - | E | |
| Investment costs; service line, 50-100 kW (EUR/unit) | - | - | - | - | - | - | - | - | E | |
| Investment costs; service line, above 100 kW (EUR/unit) | - | - | - | - | - | - | - | - | E | |
| Investment costs; single line, 0-50 kW (EUR/m) | 53 | 53 | 53 | 53 | 48 | 59 | 48 | 59 | F | |
| Investment costs; single line, 50-250 kW (EUR/m) | 53 | 53 | 53 | 53 | 48 | 59 | 48 | 59 | F | |
| Investment costs; single line, 100-250 kW (EUR/m) | 53 | 53 | 53 | 53 | 48 | 59 | 48 | 59 | F | |
| Investment costs; single line, 250 kW - 1 MW (EUR/m) | 53 | 53 | 53 | 53 | 48 | 59 | 48 | 59 | F | |
| Investment costs; single line, 1 MW - 5 MW (EUR/m) | 60 | 60 | 60 | 60 | 54 | 66 | 54 | 66 | G | |
| Investment costs; single line, 5 MW - 25 MW (EUR/m) | 87 | 87 | 87 | 87 | 78 | 95 | 78 | 95 | G | |
| Investment costs; single line, 25 MW - 100 MW (EUR/m) | - | - | - | - | - | - | - | - | | |
| Reinforcement costs (EUR/MW) | - | - | - | - | - | - | - | - | H | |
| Type 1 station (EUR/MW) | - | - | - | - | - | - | - | - | I | |
| Type 2 station (EUR/MW) | - | - | - | - | - | - | - | - | I | |
| Investments, percentage installation | 80% | 80% | 80% | 80% | 70% | 90% | 70% | 90% | | 2 |
| Investments, percentage materials | 20% | 20% | 20% | 20% | 10% | 30% | 10% | 30% | | 2 |
| Fixed O&M (EUR/MW/year) | 310 | 310 | 310 | 310 | 250 | 370 | 250 | 370 | | 2 |
| Variable O&M (EUR/MWh) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 2 |

## *Notes*

A There are no general data available for the Danish gas system. The stated losses are based on a European survey. European gas networks are generally older than the Danish system. Therefore, it is expected the losses from the Danish system are significantly lower than stated in the table. The lack of data explains the high uncertainty stated.

B As mentioned in the qualitative description, new gas systems will be constructed without stations in the distribution network

C There is no power consuming parts in the distribution system

D Based on given case

E Capacity range not relevant for given case

F Stated number is for Ø40 pipes - the smallest pipe applied. It is only marginally cheaper to apply smaller pipes.

G Two pipes were chosen for each interval (one for the lowest power level and one for the highest). The average of these two is stated in the table.

H Reinforcement not relevant

I No station will be installed for the distribution network

## *References*

1 Survey methane emissions for gas transmission and distribution in Europe Marcogaz WG-ME-14-26 29/02/2016

2 HMN Naturgas

## Table 9: Gas distribution, city

| Technology | Natural Gas Distribution, city areas | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2020 | 2030 | 2050 | Uncertainty (2020) | | Uncertainty (2050) | | Note | Ref |
| **Energy/technical data** | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines (%) | - | - | - | - | - | - | - | - | A | 1 |
| Energy losses, stations (%) | - | - | - | - | - | - | - | - | B | 1 |
| Auxiliary electricity consumption (% of energy delivered) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | C | 1 |
| Technical life time (years) | 50 | 50 | 50 | 50 | 50 | 80 | 50 | 80 | | 1 |
| Typical load profile (-) | | | | | | | | | D | |
| - Residential | 0,2 | 0.2 | 0.2 | 0.2 | 0.15 | 0.25 | 0.15 | 0.25 | D | |
| - Commercial | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | D | |
| Construction time (years) | 0,4 | 0,4 | 0,4 | 0,4 | 0,3 | 0,5 | 0,3 | 0,5 | | 1 |
| | | | | | | | | | | |
| **Financial data** | | | | | | | | | | |
| Distribution network costs (EUR/MWh/year) City | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | | 1 |
| Investment costs; service line, 0 - 20 kW (EUR/unit) | - | - | - | - | - | - | - | - | | |
| Investment costs; service line, 20 - 50 kW (EUR/unit) | - | - | - | - | - | - | - | - | | |
| Investment costs; service line, 50-100 kW (EUR/unit) | - | - | - | - | - | - | - | - | | |
| Investment costs; service line, above 100 kW (EUR/unit) | 15.000 | 15.000 | 15.000 | 15.000 | 12.000 | 18.000 | 12.000 | 18.000 | E | 1 |
| Investment costs; single line, 0-50 kW (EUR/m) | 64 | 64 | 64 | 64 | 58 | 70 | 58 | 70 | | 1 |
| Investment costs; single line, 50-250 kW (EUR/m) | 64 | 64 | 64 | 64 | 58 | 70 | 58 | 70 | | 1 |
| Investment costs; single line, 100-250 kW (EUR/m) | 64 | 64 | 64 | 64 | 58 | 70 | 58 | 70 | | 1 |
| Investment costs; single line, 250 kW - 1 MW (EUR/m) | 64 | 64 | 64 | 64 | 58 | 70 | 58 | 70 | | 1 |
| Investment costs; single line, 1 MW - 5 MW (EUR/m) | 72 | 72 | 72 | 72 | 65 | 79 | 65 | 79 | | 1 |
| Investment costs; single line, 5 MW - 25 MW (EUR/m) | 104 | 104 | 104 | 104 | 94 | 114 | 94 | 114 | | 1 |
| Investment costs; single line, 25 MW - 100 MW (EUR/m) | - | - | - | - | - | - | - | - | F | |
| Reinforcement costs (EUR/MW) | - | - | - | - | - | - | - | - | F | |
| Type 1 station (EUR/MW) | - | - | - | - | - | - | - | - | F | |
| Type 2 station (EUR/MW) | - | - | - | - | - | - | - | - | F | |
| Investments, percentage installation | 80% | 80% | 80% | 80% | 70% | 90% | 70% | 90% | | 1 |
| Investments, percentage materials | 20% | 20% | 20% | 20% | 10% | 30% | 10% | 30% | | 1 |
| Fixed O&M (EUR/MW/year) | 20 | 20 | 20 | 20 | 16 | 24 | 16 | 24 | | 1 |
| Variable O&M (EUR/MWh) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 1 |

## *Notes*

A For the defined case "New distribution in existing densely populated areas, city centres etc." it is assessed the natural gas based heating will be designed with one boiler and heat is distributed to the end users by a local district heating system. This means that the local natural gas system will only consist of a service line with a capacity of 1.5 MW supplying a boiler as well a meter and a pressure regulator. Therefore, losses are neglected

B As mentioned in the qualitative description, new gas systems will be constructed without stations in the distribution network

C There is no power consuming parts in the distribution system

D Based on given case

E Stated number is for a service line supplying 1,5 MW.

F Not relevant, see note A

## *References*

1 HMN Naturgas

### Table 10: Gas distribution, new developed area

| Technology | Natural Gas Distribution, New developed areas | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2020 | 2030 | 2050 | Uncertainty (2020) | | Uncertainty (2050) | | Note | Ref |
| **Energy/technical data** | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines (%) | 0,26 | 0,26 | 0,26 | 0,26 | 0,05 | 0,3 | 0,05 | 0,3 | A | 1 |
| Energy losses, stations (%) | - | - | - | - | - | - | - | - | B | |
| Auxiliary electricity consumption (% of energy delivered) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | C | |
| Technical life time (years) | 50 | 50 | 50 | 50 | 50 | 80 | 50 | 80 | | 2 |
| Typical load profile (-) | - | - | - | - | - | - | - | - | | |
| - Residential | 0,2 | 0,2 | 0,2 | 0,2 | 0,15 | 0,25 | 0,15 | 0,25 | D | |
| - Commercial | N/A | N/A | N/A | N/A | | | | | D | |
| Construction time (years) | 0,4 | 0,4 | 0,4 | 0,4 | 0,3 | 0,5 | 0,3 | 0,5 | | 2 |
| | | | | | | | | | | |
| **Financial data** | | | | | | | | | | |
| Distribution network costs (EUR/MWh/year) City | 270 | 270 | 270 | 270 | 240 | 300 | 240 | 300 | | 2 |
| Investment costs; service line, 0 - 20 kW (EUR/unit) | 1600 | 1600 | 1600 | 1600 | 1400 | 1800 | 1400 | 1800 | | 2 |
| Investment costs; service line, 20 - 50 kW (EUR/unit) | - | - | - | - | - | - | - | - | E | |
| Investment costs; service line, 50-100 kW (EUR/unit) | - | - | - | - | - | - | - | - | E | |
| Investment costs; service line, above 100 kW (EUR/unit) | - | - | - | - | - | - | - | - | E | |
| Investment costs; single line, 0-50 kW (EUR/m) | 47 | 47 | 47 | 47 | 42 | 51 | 42 | 51 | F | |
| Investment costs; single line, 50-250 kW (EUR/m) | **47** | 47 | 47 | 47 | 42 | 51 | 42 | 51 | F | |
| Investment costs; single line, 100-250 kW (EUR/m) | 47 | 47 | 47 | 47 | 42 | 51 | 42 | 51 | F | |
| Investment costs; single line, 250 kW - 1 MW (EUR/m) | 47 | 47 | 47 | 47 | 42 | 51 | 42 | 51 | F | |
| Investment costs; single line, 1 MW - 5 MW (EUR/m) | 50 | 50 | 50 | 50 | 45 | 55 | 45 | 55 | G | |
| Investment costs; single line, 5 MW - 25 MW (EUR/m) | 63 | 63 | 63 | 63 | 57 | 70 | 57 | 70 | G | |
| Investment costs; single line, 25 MW - 100 MW (EUR/m) | - | - | - | - | - | - | - | - | | |
| Reinforcement costs (EUR/MW) | - | - | - | - | - | - | - | - | H | |
| Type 1 station (EUR/MW) | - | - | - | - | - | - | - | - | I | |
| Type 2 station (EUR/MW) | - | - | - | - | - | - | - | - | I | |
| Investments, percentage installation | 80% | 80% | 80% | 80% | 70% | 90% | 70% | 90% | | 2 |
| Investments, percentage materials | 20% | 20% | 20% | 20% | 10% | 30% | 10% | 30% | | 2 |
| Fixed O&M (EUR/MW/year) | 920 | 920 | 920 | 920 | 740 | 1100 | 740 | 1100 | | 2 |
| Variable O&M (EUR/MWh) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 2 |

## *Notes*

A There are no general data available for the Danish gas system. The stated losses are based on a European survey. European gas networks are generally older than the Danish system. Therefore, it is expected the losses from the Danish system are significantly lower than stated in the table. The lack of data explains the high uncertainty stated.

B As mentioned in the qualitative description, new gas systems will be constructed without stations in the distribution network

C There is no power consuming parts in the distribution system

D Based on given case

E Capacity range not relevant for given case

F Stated number is for Ø40 pipes - the smallest pipe applied. It is only marginally cheaper to apply smaller pipes.

G Two pipes were chosen for each interval (one for the lowest power level and one for the highest). The average of these two is stated in the table.

H Reinforcement not relevant

I No station will be installed for the distribution network

## *References*

1 Survey methane emissions for gas transmission and distribution in Europe Marcogaz WG-ME-14-26 29/02/2016

2 HMN Naturgas

# 113 District heating distribution and transmission grid

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February 2025

**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 DH 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 1, 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.

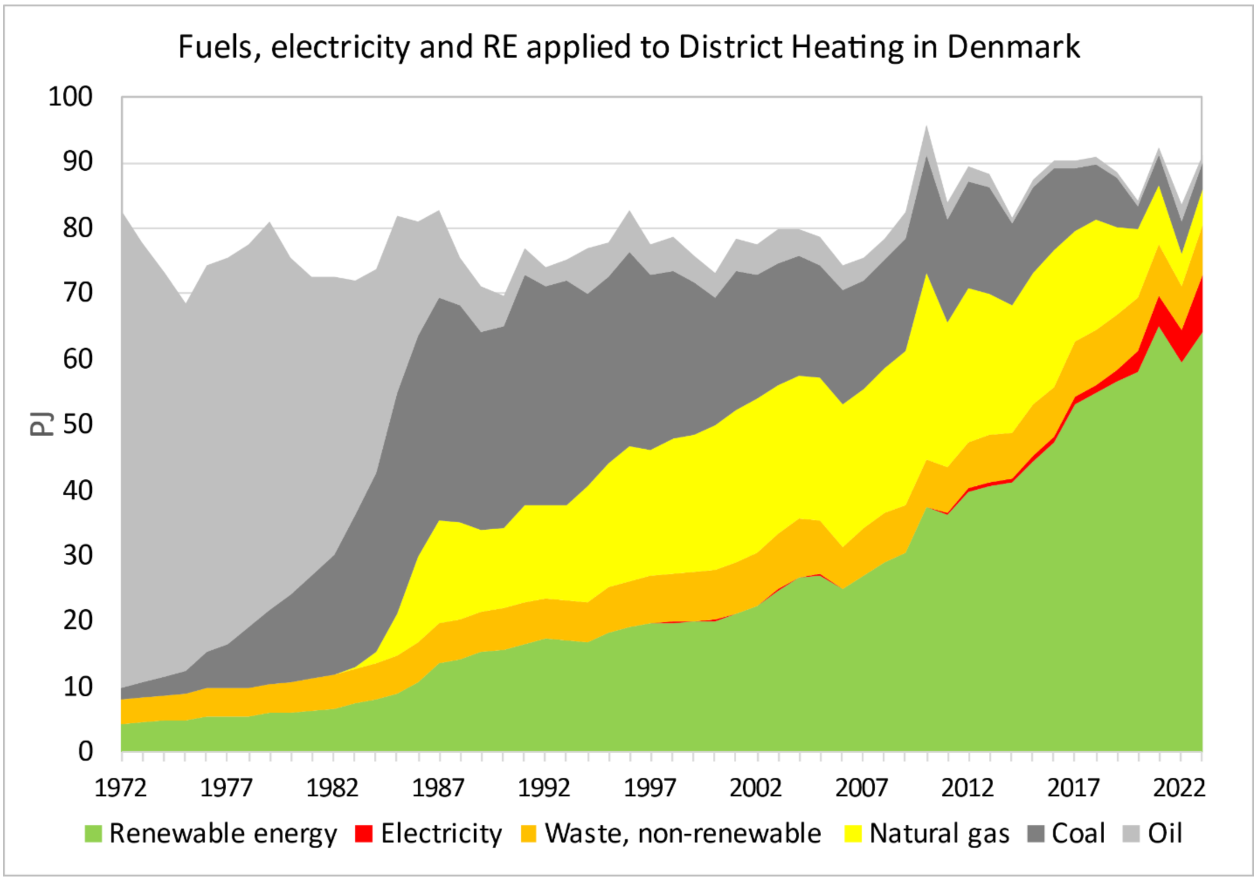


Figure 1 - Fuels applied in District Heating in Denmark. Kilde: Energistyrelsen – energistatistik 2023.

### 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 2 below. In small scale DH networks, the transmission pipe would be replaced by a large distribution pipe.

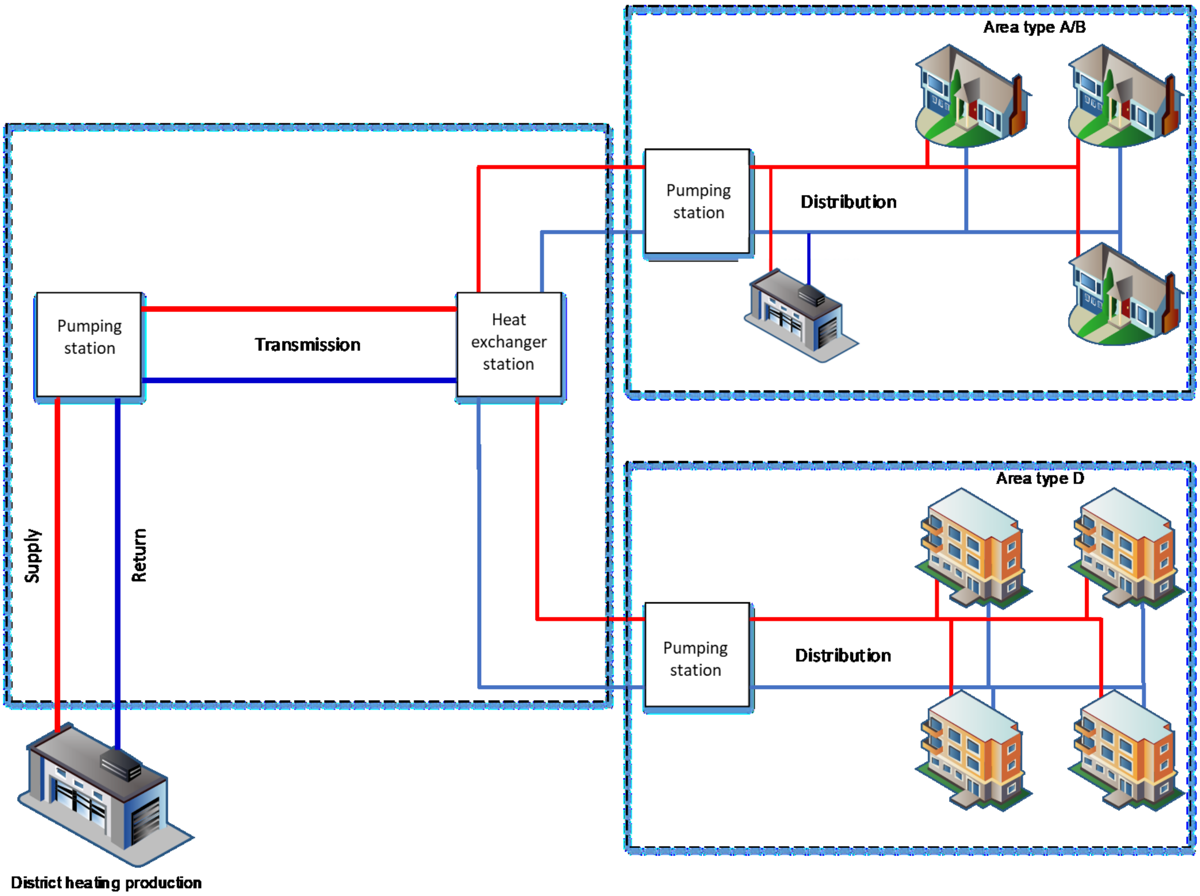


Figure 2 - District Heating Network

### *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 **Fejl! Henvisningskilde ikke fundet.**. An explanation of the pipe types is given in the section: *Examples of market standard technology*.

| **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 |

**Table 11 - Space requirements, span from the smallest (DN50) to largest distribution pipes (DN250).**

### 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 3.

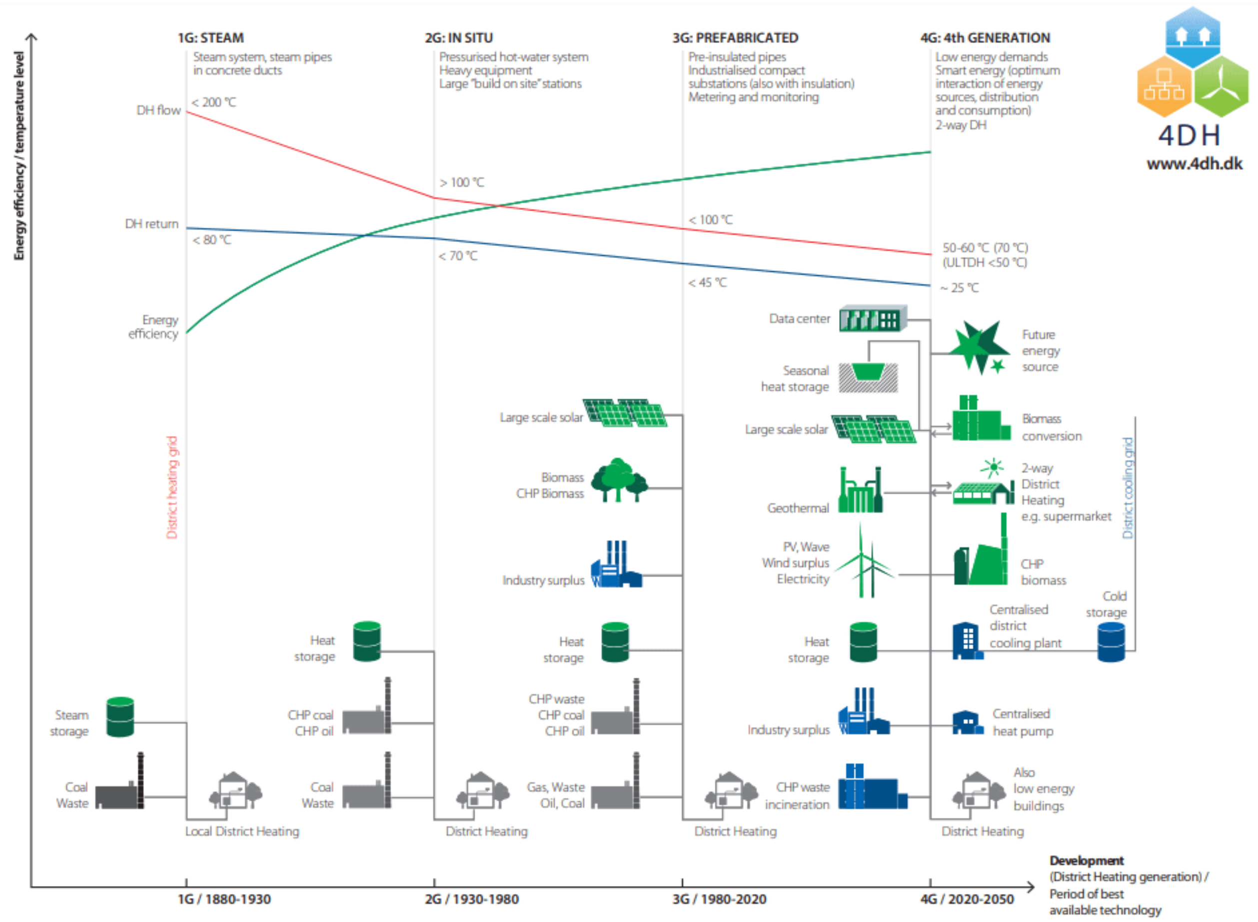


**Figure 3 - Evolution in temperature reduction (4DH Research Centre, 2024) . Note: DH flow is the same as DH supply.**

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 4 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 4 - Twinpipes – Steel and flexible PE pipe**

### Prediction of performance and costs

As shown in Figure 5, 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.

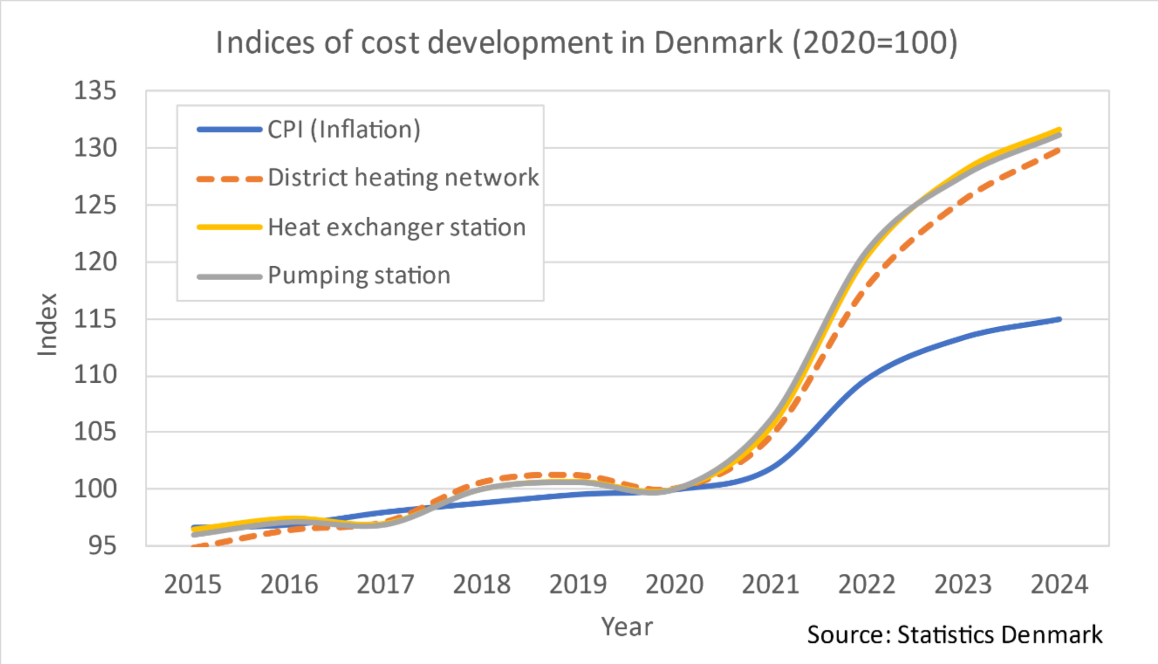


**Figure 5 - Cost development 2015-2024 for district heating networks, large heat exchanger stations and pumping stations based on cost indexes from Statistics Denmark**

## Technology data sheets

The technology in the data sheets below refers to 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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## Data sheets

### Table 11: District heating Transmission

| Technology | Energy Transport District Heating Transmission | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year 2020 (fixed prices) | 2020 | 2025 | 2030 | 2035 | 2040 | 2050 | 2025 | 2025 | 2050 | 2050 | Note | Ref |
| **Energy/technical data** | | | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, lines 1-20 MW [% per km] | 1 | 1 | 1 | 1 | 1 | 1 | 0,8 | 1,5 | 0,8 | 1,2 | A | [1, 2] |
| Energy losses, lines 20-100 MW [% per km] | 0,25 | 0,25 | 0,25 | 0,25 | 0,25 | 0,25 | 0,2 | 0,375 | 0,2 | 0,3 | A | [1, 2] |
| Energy losses, lines above 100 MW [% per km] | 0,1 | 0,1 | 0,1 | 0,1 | 0,1 | 0,1 | 0,08 | 0,15 | 0,08 | 0,12 | A | [1, 2] |
| Energy losses, Heat exchanger stations [%] | 1 | 1 | 1 | 1 | 1 | 1 | 0,8 | 1,5 | 0,8 | 1,2 | | 1 |
| Energy losses, Pumping stations [%] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | G | 1 |
| Auxiliary electricity consumption [%] energy transmitted | 1 | 1 | 1 | 1 | 1 | 1 | 0.5 | 2 | 0.5 | 2 | | [1, 4] |
| Technical life time [years] | 45 | 45 | 45 | 45 | 45 | 45 | 30 | 60 | 30 | 60 | B | [1, 2] |
| Typical load profile (-) | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.4 | 0.6 | 0.4 | 0.6 | | 1 |
| Construction time [years] | 2,5 | 2,5 | 2,5 | 2,5 | 2,5 | 2,5 | 1,5 | 4 | 1,5 | 4 | | 1 |
| **Financial data** | | | | | | | | | | | | |
| Investment costs; single line, 0 - 50 MW [EUR/MW/m] | 56 | 63 | 63 | 63 | 63 | 63 | 51 | 75 | 51 | 75 | [C, D] | [1, 3] |
| Investment costs; single line, 50-100 MW [EUR/MW/m] | 28 | 32 | 32 | 32 | 32 | 32 | 25 | 37 | 25 | 37 | [C, D] | [1, 3] |
| Investment costs; single line, 100 - 250 MW [EUR/MW/m] | 17 | 20 | 20 | 20 | 20 | 20 | 16 | 23 | 16 | 23 | [C, D] | [1, 3] |
| Investment costs; single line, 250-500 MW [EUR/MW/m] | 11 | 12 | 12 | 12 | 12 | 12 | 10 | 14 | 10 | 14 | [C, D] | [1, 3] |
| Investment costs; single line, 500-1000 MW [EUR/MW/m] | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Investment costs; single line, above 1000 MW [EUR/MW/m] | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Fixed O&M [EUR/MW/km/year] | 100 | 100 | 100 | 100 | 100 | 100 | 50 | 200 | 50 | 200 | | |
| Variable O&M [EUR/MWh/km] | 0,1 | 0,1 | 0,1 | 0,1 | 0,1 | 0,1 | 0 | 2 | 0 | 2 | | [1, 4] |
| Investments, percentage installation | 60% | 60% | 60% | 60% | 60% | 60% | 50% | 70% | 50% | 70% | C | 2 |
| Investments, percentage materials | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | | 2 |
| Investment, percentage soft cost | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | F | 2 |
| **Technology-specific data** | | | | | | | | | | | | |
| Reinforcement costs [EUR/MW] | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | E | |
| Investment costs; Heat exchanger station [EUR/MW] | 122.288 | 140.162 | 140.162 | 140.162 | 140.162 | 140.162 | 77.089 | 168.194 | 77.089 | 168.194 | | 1 |
| Investment costs; Pump station [EUR/MW] | 111.654 | 127.473 | 127.473 | 127.473 | 127.473 | 127.473 | 70.110 | 152.968 | 70.110 | 152.968 | | 1 |

**References:**

1. Based on Ramboll experience figures

2. LOGSTOR A/S

3. Consolidated w ith data from Danish District Heating Association

4. Consolidated w ith statistics from Danish District Heating Association 2020

**Notes:**

A. The loss is per trench km of transmission pipeline pair.

B. The technical life time of a district heating pipe is minimum 30 years. How ever the life time can be substantially longer depending on operation conditions e.g. temperaturevariation, soil conditions etc.

C. The cost is per trench meter transmission pipeline pair in unpaved areas.

D. Tw o district heating pipes w ere chosen for each interval (one for the low est effect level and one for the highest). The average of these tw o are stated in the table. For cost interpolation: P = a * C^b, w here P = cost in EUR/MW/m, C = capacity in MW, a = 330 and b =-0,571.

E. Depends on the scale of the transmission grid and supply strategy of reserve capacity. Therefore, it is not possible to generalize these costs.

F. Soft costs include design, planning, tender, permits, supervision, etc.

# Table 12: Energy Transport District Heating Distribution, Suburban

| Technology | Energy Transport District Heating Distribution, Suburban | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year 2020 (fixed prices) | 2020 | 2025 | 2030 | 2035 | 2040 | 2050 | 2025 | 2025 | 2050 | 2050 | Note | Ref |
| **Energy/technical data** | | | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, network [%] | 12 | 12 | 12 | 12 | 12 | 12 | 10 | 16 | 9 | 14 | [A, B] | 2 |
| Auxiliary electricity consumption [%] of energy delivered | 2 | 2 | 2 | 2 | 2 | 2 | 0,5 | 3 | 0,5 | 3 | | 4 |
| Technical life time [years] | 45 | 45 | 45 | 45 | 45 | 45 | 30 | 60 | 30 | 60 | C | 2 |
| Typical load factor (-) | | | | | | | | | | | | |
| - Residential | 0,2 | 0,2 | 0,2 | 0,2 | 0,2 | 0,2 | 0.18 | 0.22 | 0.18 | 0.22 | | |
| - Commercial | 0,2 | 0,2 | 0,2 | 0,2 | 0,2 | 0,2 | 0.15 | 0.25 | 0.15 | 0.25 | | |
| Construction time [years] | 2 | 2 | 2 | 2 | 2 | 2 | 1 | 3 | 1 | 3 | | |
| **Financial data** | | | | | | | | | | | | |
| Investments cost, distribution network [MEUR/km2] | 6,5 | 7,3 | 7,3 | 7,3 | 7,3 | 7,3 | 5,5 | 9,1 | 5,5 | 9,1 | [D, E] | [1, 3] |
| Investments, percentage installation | 60% | 60% | 60% | 60% | 60% | 60% | 50% | 70% | 50% | 70% | E | 2 |
| Investments, percentage materials | 25% | 25% | 25% | 25% | 25% | 25% | 20% | 30% | 20% | 30% | E | 2 |
| Investment, percentage soft costs percentage | 15% | 15% | 15% | 15% | 15% | 15% | 10% | 20% | 10% | 20% | H | 2 |
| Fixed O&M [EUR/MW/year] | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 750 | 2.000 | 750 | 2.000 | M | 1 |
| Variable O&M [EUR/MWh] | 2,0 | 2,0 | 2,0 | 2,0 | 2,0 | 2,0 | 1,5 | 3,0 | 1,5 | 3,0 | M | [1, 4] |
| **Technology-specific data** | | | | | | | | | | | | |
| Investment costs; service line, 0 - 20 kW [EUR/unit] | 4.165 | 4.706 | 4.706 | 4.706 | 4.706 | 4.706 | 3.243 | 6.192 | 3.243 | 6.192 | [B, E, F, J] | [1, 3] |
| Investment costs; service line, 20 - 50 kW [EUR/unit] | 4.519 | 5.107 | 5.107 | 5.107 | 5.107 | 5.107 | 3.548 | 6.679 | 3.548 | 6.679 | [B, E, F, J] | [1, 3] |
| Investment costs; service line, 50-100 kW [EUR/unit] | 4.987 | 5.636 | 5.636 | 5.636 | 5.636 | 5.636 | 3.953 | 7.310 | 3.953 | 7.310 | [B, E, F, J] | [1, 3] |
| Investment costs; service line, above 100 kW [EUR/unit] | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | K | |
| Investment costs; single line, 0-50 kW [EUR/m] | 308 | 349 | 349 | 349 | 349 | 349 | 241 | 456 | 241 | 456 | [B, E, G] | [1, 3] |
| Investment costs; single line, 50-250 kW [EUR/m] | 390 | 441 | 441 | 441 | 441 | 441 | 327 | 554 | 327 | 554 | [B, E, G] | [1, 3] |
| Investment costs; single line, 100-250 kW [EUR/m] | 407 | 459 | 459 | 459 | 459 | 459 | 342 | 577 | 342 | 577 | [B, E, G] | [1, 3] |
| Investment costs; single line, 250 kW - 1 MW [EUR/m] | 516 | 583 | 583 | 583 | 583 | 583 | 457 | 700 | 457 | 700 | [B, E, G] | [1, 3] |
| Investment costs; single line, 1 MW - 5 MW [EUR/m] | 725 | 819 | 819 | 819 | 819 | 819 | 646 | 971 | 646 | 971 | [B, E, G] | [1, 3] |
| Investment costs; single line, 5 MW - 25 MW [EUR/m] | 1.309 | 1.479 | 1.479 | 1.479 | 1.479 | 1.479 | 1.184 | 1.753 | 1.184 | 1.753 | [B, E, G] | [1, 3] |
| Investment costs; single line, 25 MW - 100 MW [EUR/m] | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | L | |
| Reinforcement costs [EUR/MW] | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Pumping station above 1 MW [EUR/MW] | 98.736 | 112.725 | 112.725 | 112.725 | 112.725 | 112.725 | 61.999 | 135.270 | 61.999 | 135.270 | I | 1 |
| Pumping station below 1 MW [EUR/MW] | 255.209 | 291.367 | 263.880 | 263.880 | 263.880 | 263.880 | 160.252 | 349.641 | 160.252 | 349.641 | I | 1 |

**References:**


1. Based on Ramboll experience figures. Costs have been deflated by a factor of 0.870 to 2020-EURO from project data in 2024.
2. Ramboll experience and technical data from LOGSTOR A/S
3. Consolidated with data from Danish District Heating Association
4. Consolidated with statistics from Danish District Heating Association 2020


**Notes:**

A. For entire distribution network inclusive pump stations and service lines. For pump stations the heat loss is negligible.

B. Twin pipes assumed up to 5 MW and pipe pairs for larger pipe capacities

C. The technical life time of a district heating pipe is minimum 30 years. However the life time can be substantially longer depending on operation conditions e.g. temperaturevariation, soil conditions etc.

D. The distribution network costs are inclusive pumping stations but exclusive service pipelines and based on an area of scattered single-family houses of 1-2 floors with a heat density of 10 GWh/year/km2.

E. A paved area is assumed for the distribution network. For service lines 50 % unpaved and 50 % paved area is asumed.

F. Cost of service lines are based on an average service line lenght of 15 meters. Two service lines were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table.

G. Two district heating pipes were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table. The cost is per trench meter.

H. Soft costs include costs for design, planning, tender, permits, supervision, etc. after the final investment decision.

I. Investment costs per MW for pumping stations below 1 MW are very different from costs for stations above 1 MW.

J It is assumed that the service line is constructed at the same time as the street line. For a subsequent customer connection (saddle connection), the investment costs for service lines are increased by 33%

K. Service lines above 100 kW are not relevant in the specific area type.

L. Single lines above 25 MW are not relevant in the specific area type.

M. The amount of thermal energy in MWh can be calculated from the heat density mentioned in note D. The effect in MW equals: amount of energy [MWh]/(8760·load factor). For a district heating system, the load factor is around 0.34.

## Table 13: Energy Transport District Heating Distribution, City

| Technology | Energy Transport District Heating Distribution, City | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year 2020 (fixed prices) | 2020 | 2025 | 2030 | 2035 | 2040 | 2050 | 2025 | 2025 | 2050 | 2050 | Note | Ref |
| **Energy/technical data** | | | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, network [%] | 7 | 7 | 7 | 7 | 7 | 7 | 5 | 9 | 4 | 8 | [A, B] | 2 |
| Auxiliary electricity consumption [%] of energy delivered | 2 | 2 | 2 | 2 | 2 | 2 | 0,5 | 3 | 0,5 | 3 | | 4 |
| Technical life time [years] | 45 | 45 | 45 | 45 | 45 | 45 | 30 | 60 | 30 | 60 | C | 2 |
| Typical load factor (-) | | | | | | | | | | | | |
| - Residential | 0,2 | 0,2 | 0,2 | 0,2 | 0,2 | 0,2 | 0.18 | 0.25 | 0.18 | 0.25 | | |
| - Commercial | 0,2 | 0,2 | 0,2 | 0,2 | 0,2 | 0,2 | 0.15 | 0.25 | 0.15 | 0.25 | | |
| Construction time [years] | 2 | 2 | 2 | 2 | 2 | 2 | 1 | 3 | 1 | 3 | | |
| **Financial data** | | | | | | | | | | | | |
| Investments cost, distribution network [MEUR/km2] | 6,0 | 6,7 | 6,7 | 6,7 | 6,7 | 6,7 | 5,0 | 8,4 | 5,0 | 8,4 | [D, E] | [1, 3] |
| Investments, percentage installation | 60% | 60% | 60% | 60% | 60% | 60% | 50% | 70% | 50% | 70% | E | 2 |
| Investments, percentage materials | 25% | 25% | 25% | 25% | 25% | 25% | 20% | 30% | 20% | 30% | E | 2 |
| Investment, percentage soft costs | 15% | 15% | 15% | 15% | 15% | 15% | 10% | 20% | 10% | 20% | H | 2 |
| Fixed O&M [EUR/MW/year] | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 750 | 2.000 | 750 | 2.000 | M | 1 |
| Variable O&M [EUR/MWh] | 2,0 | 2,0 | 2,0 | 2,0 | 2,0 | 2,0 | 1,5 | 3,0 | 1,5 | 3,0 | M | [1, 4] |
| **Technology-specific data** | | | | | | | | | | | | |
| Investment costs; service line, 0 - 20 kW [EUR/unit] | 4.961 | 5.607 | 5.607 | 5.607 | 5.607 | 5.607 | 3.805 | 7.432 | 3.805 | 7.432 | [B, E, F, J] | [1, 3] |
| Investment costs; service line, 20 - 50 kW [EUR/unit] | 5.334 | 6.028 | 6.028 | 6.028 | 6.028 | 6.028 | 4.135 | 7.883 | 4.135 | 7.883 | [B, E, F, J] | [1, 3] |
| Investment costs; service line, 50-100 kW [EUR/unit] | 5.827 | 6.585 | 6.585 | 6.585 | 6.585 | 6.585 | 4.627 | 8.482 | 4.627 | 8.482 | [B, E, F, J] | [1, 3] |
| Investment costs; service line, above 100 kW [EUR/unit] | 7.160 | 8.091 | 8.091 | 8.091 | 8.091 | 8.091 | 6.264 | 9.918 | 6.264 | 9.918 | [B, E, F, J, K] | [1, 3] |
| Investment costs; single line, 0-50 kW [EUR/m] | 339 | 383 | 383 | 383 | 383 | 383 | 262 | 507 | 262 | 507 | [B, E, G] | [1, 3] |
| Investment costs; single line, 50-100 kW [EUR/m] | 380 | 430 | 430 | 430 | 430 | 430 | 303 | 560 | 303 | 560 | [B, E, G] | [1, 3] |
| Investment costs; single line, 100-250 kW [EUR/m] | 441 | 499 | 499 | 499 | 499 | 499 | 372 | 625 | 372 | 625 | [B, E, G] | [1, 3] |
| Investment costs; single line, 250 kW - 1 MW [EUR/m] | 551 | 623 | 623 | 623 | 623 | 623 | 488 | 749 | 488 | 749 | [B, E, G] | [1, 3] |
| Investment costs; single line, 1 MW - 5 MW [EUR/m] | 773 | 874 | 874 | 874 | 874 | 874 | 692 | 1.035 | 692 | 1.035 | [B, E, G] | [1, 3] |
| Investment costs; single line, 5 MW - 25 MW [EUR/m] | 1.390 | 1.571 | 1.571 | 1.571 | 1.571 | 1.571 | 1.259 | 1.863 | 1.259 | 1.863 | [B, E, G] | [1, 3] |
| Investment costs; single line, 25 MW - 100 MW [EUR/m] | 2.533 | 2.862 | 2.862 | 2.862 | 2.862 | 2.862 | 2.306 | 3.393 | 2.306 | 3.393 | [B, E, G, L] | [1, 3] |
| Reinforcement costs [EUR/MW] | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Pumping station above 1 MW [EUR/MW] | 98.736 | 112.725 | 112.725 | 112.725 | 112.725 | 112.725 | 61.999 | 135.270 | 61.999 | 143.842 | I | 1 |
| Pumping station below 1 MW [EUR/MW] | 255.209 | 291.367 | 291.367 | 291.367 | 291.367 | 291.367 | 160.252 | 349.641 | 160.252 | 349.641 | I | 1 |


**References:**

1. Based on Ramboll experience figures. Costs have been deflated by a factor of 0.870 to 2020-EURO from project data in 2024.
2. Ramboll experience and technical data from LOGSTOR A/S
3. Consolidated with data from Danish District Heating Association
4. Consolidated with statistics from Danish District Heating Association 2020


**Notes:**

A. For entire distribution network inclusive pump stations and service lines. For pump stations the heat loss is negligible.

B. Twin pipes assumed up to 5 MW and pipe pairs for larger pipe capacities.

C. The technical life time of a district heating pipe is minimum 30 years. However the life time can be substantially longer depending on operation conditions e.g. temperaturevariation, soil conditions etc.

D. The distribution network costs are inclusive pumping stations but exclusive service pipelines and based on mixed densely packed buildings in 2-3 storeys and with a heat density of 15 GWh/year/km2.

E. A paved area is assumed for the distribution network as well as for service lines.

F. Cost of service lines are based on an average service line lenght of 15 meters. Two service lines were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table.

G. Two district heating pipes were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table. The cost is per trench meter.

H. Soft costs include costs for design, planning, tender, permits, supervision, etc. after the final investment decision.

I. Investment costs per MW for pumping stations below 1 MW are very different from costs for stations above 1 MW.

J It is assumed that the service line is constructed at the same time as the street line. For a subsequent customer connection (saddle connection), the investment costs for service lines are increased by 33%

K. The value stated is for a DN50 twin pipe. This pipe size is able to deliver up to around 250 kW. If a higher capacity is needed the price will increase.

L. The value stated is for a DN400 pipe pair. This pipe size is able to deliver up to around 45 MW. If a higher capacity is needed the price will increase.

M. The amount of thermal energy in MWh can be calculated from the heat density mentioned in note D. The effect in MW equals: amount of energy [MWh]/(8760·load factor). For a district heating system, the load factor is around 0.34.

# Table 14: Energy Transport District Heating Distribution, New Area

| Technology | Energy Transport District Heating Distribution, New Area | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year 2020 (fixed prices) | 2020 | 2025 | 2030 | 2035 | 2040 | 2050 | 2025 | 2025 | 2050 | 2050 | Note | Ref |
| **Energy/technical data** | | | | | | | Lower | Upper | Lower | Upper | | |
| Energy losses, network [%] | 18 | 18 | 18 | 18 | 18 | 18 | 12 | 24 | 10 | 20 | [A, B] | 2 |
| Auxiliary electricity consumption [%] of energy delivered | 2 | 2 | 2 | 2 | 2 | 2 | 0,5 | 3 | 0,5 | 3 | | 4 |
| Technical life time [years] | 45 | 45 | 45 | 45 | 45 | 45 | 30 | 60 | 30 | 60 | C | 2 |
| Typical load factor (-) | | | | | | | | | | | | |
| - Residential | 0,17 | 0,17 | 0,17 | 0,17 | 0,17 | 0,17 | 0.1 | 0.2 | 0.1 | 0.2 | | |
| - Commercial | 0,17 | 0,17 | 0,17 | 0,17 | 0,17 | 0,17 | 0.1 | 0.2 | 0.1 | 0.2 | | |
| Construction time [years] | 1 | 1 | 1 | 1 | 1 | 1 | 0.5 | 2 | 0.5 | 2 | | |
| **Financial data** | | | | | | | | | | | | |
| Investments cost, distribution network [MEUR/km2] | 4,7 | 5,3 | 5,3 | 5,3 | 5,3 | 5,3 | 4,0 | 6,6 | 4,0 | 6,6 | [D, E] | [1, 3] |
| Investments, percentage installation | 60% | 60% | 60% | 60% | 60% | 60% | 50% | 70% | 50% | 70% | E | 2 |
| Investments, percentage materials | 25% | 25% | 25% | 25% | 25% | 25% | 20% | 30% | 20% | 30% | E | 2 |
| Investment, percentage soft costs | 15% | 15% | 15% | 15% | 15% | 15% | 10% | 20% | 10% | 20% | H | 2 |
| Fixed O&M [EUR/MW/year] | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 750 | 2.000 | 750 | 2.000 | M | 1 |
| Variable O&M [EUR/MWh] | 1,60 | 1,7 | 1,7 | 1,7 | 1,7 | 1,7 | 1,3 | 2,6 | 1,3 | 2,6 | M | [1, 4] |
| **Technology-specific data** | | | | | | | | | | | | |
| Investment costs; service line, 0 - 20 kW [EUR/unit] | 3.504 | 3.960 | 3.960 | 3.960 | 3.960 | 3.960 | 2.707 | 5.231 | 2.707 | 5.231 | [B, E, F, J] | [1, 3] |
| Investment costs; service line, 20 - 50 kW [EUR/unit] | 3.784 | 4.276 | 4.276 | 4.276 | 4.276 | 4.276 | 2.951 | 5.593 | 2.951 | 5.593 | [B, E, F, J] | [1, 3] |
| Investment costs; service line, 50-100 kW [EUR/unit] | 4.154 | 4.694 | 4.694 | 4.694 | 4.694 | 4.694 | 3.296 | 6.066 | 3.296 | 6.066 | [B, E, F, J] | [1, 3] |
| Investment costs; service line, above 100 kW [EUR/unit] | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | K | |
| Investment costs; single line, 0-50 kW [EUR/m] | 243 | 274 | 274 | 274 | 274 | 274 | 189 | 361 | 189 | 361 | [B, E, G] | [1, 3] |
| Investment costs; single line, 50-250 kW [EUR/m] | 302 | 342 | 342 | 342 | 342 | 342 | 253 | 431 | 253 | 431 | [B, E, G] | [1, 3] |
| Investment costs; single line, 100-250 kW [EUR/m] | 318 | 359 | 359 | 359 | 359 | 359 | 268 | 451 | 268 | 451 | [B, E, G] | [1, 3] |
| Investment costs; single line, 250 kW - 1 MW [EUR/m] | 400 | 452 | 452 | 452 | 452 | 452 | 354 | 543 | 354 | 543 | [B, E, G] | [1, 3] |
| Investment costs; single line, 1 MW - 5 MW [EUR/m] | 562 | 635 | 635 | 635 | 635 | 635 | 502 | 752 | 502 | 752 | [B, E, G] | [1, 3] |
| Investment costs; single line, 5 MW - 25 MW [EUR/m] | 1.012 | 1.144 | 1.144 | 1.144 | 1.144 | 1.144 | 916 | 1.356 | 916 | 1.356 | [B, E, G] | [1, 3] |
| Investment costs; single line, 25 MW - 100 MW [EUR/m] | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | L | |
| Reinforcement costs [EUR/MW] | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Pumping station above 1 MW [EUR/MW] | 92.764 | 105.907 | 105.907 | 105.907 | 105.907 | 105.907 | 59.308 | 127.088 | 59.308 | 127.088 | I | 1 |
| Pumping station below 1 MW [EUR/MW] | 247.371 | 282.419 | 282.419 | 282.419 | 282.419 | 282.419 | 158.154 | 338.902 | 158.154 | 338.902 | I | 1 |

**References:**


1. Based on Ramboll experience figures. Costs have been deflated by a factor of 0.870 to 2020-EURO from project data in 2024.

2. Ramboll experience and technical data from LOGSTOR A/S

3. Consolidated with data from Danish District Heating Association

4. Consolidated with statistics from Danish District Heating Association 2020


**Notes:**

A. For entire distribution network inclusive pump stations and service lines. For pump stations the heat loss is negligible.

B. Twin pipes assumed up to 5 MW and pipe pairs for larger pipe capacities.

C. The technical life time of a district heating pipe is minimum 30 years. However the life time can be substantially longer depending on operation conditions e.g. temperaturevariation, soil conditions etc.

D. The distribution network costs are inclusive pumping stations but exclusive service pipelines and based on close cluster housing in 1-2 floors in shared green areas and with a heat density of 6.5 GWh/year/km2.

E. An unpaved area is assumed for the distribution network as well as for service lines. Coordination with the establishment of other infrastructure (electricity, water, sewerage) may entail construction cost benefits.

F. Cost of service lines are based on an average service line lenght of 15 meters. Two service lines were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table.

G. Two district heating pipes were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table. The cost is per trench meter.

H. Soft costs include costs for design, planning, tender, permits, supervision, etc. after the final investment decision.

I. Investment costs per MW for pumping stations below 1 MW are very different from costs for stations above 1 MW.

J It is assumed that the service line is constructed at the same time as the street line. For a subsequent customer connection (saddle connection), the investment costs for service lines are increased by 50%

K. Service lines above 100 kW are not relevant in the specific area type.

L. Single lines above 25 MW are not relevant in the specific area type.

M. The amount of thermal energy in MWh can be calculated from the heat density mentioned in note D. The effect in MW equals: amount of energy [MWh]/(8760·load factor). For a district heating system, the load factor is around 0.34.

For the entire table: With low-temperature district heating (LTDH), the stated heat loss of the district heating network is reduced by 20-25% and the district heating network investment is reduced by up to 5%.

# Introduction to transport of gases and liquids

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|---|---|---|
| | | |

## Abbreviations

| | | | |
|---|---|---|---|
| Amb. | Ambient condition (P=1.025 bar, T€[-50:50] °C | LPG | Liquefied petroleum gas |
| CC | Carbon Capture | M | Mass |
| CH2 | Compressed hydrogen | M/R | Metering and regulation station |
| CNG | Compressed natural gas | MTPD | Metric ton per day |
| CNO | Numb of carbon atoms in a chemical molecule | NG | Natural gas |
| CP | Cathodic protection | $NH_3$ | Ammonia |
| DME | Dimethyl-Ether | P | Pressure |
| DN | Nominal diameter | Pd | Design pressure |
| dP/dL | Pressure drop per length (bar/km) | PG | Petroleum gas |
| E | Energy | Pin | Inlet/suction pressure |
| EIGA | European industrial gases association AISBL | Pmax | Max operation pressure |
| ESD | Emergency shutdown | Pmin | Min operating pressure |
| GT | Gross Tonnage | Pout | Outlet/discharge pressure |
| $H_2$ | Hydrogen | PSA | Pressure swing adsorption unit (separate components by selective absorption at high pressure and desorption/regeneration at low pressure) |
| H2NG | Fuel group: include H2 and NG | PSV | Pressure safety valve (protect against overpressure) |

| | | | |
|---|---|---|---|
| HB | Material hardness measured by "Hardness Brinell" method | Q | Energy flow, MW |
| HC | Hydrocarbons, i.e. molecules that consist of only C and H ($C_nH_m$) | RE | Renewable power |
| HHV | Higher heating value | SCC | Stress corrosion cracking |
| HRC | Material hardness measured by "Hardness Rockwell C" method | SMR | Steam Methane Reforming |
| L20 | Fuel group: include DME, $NH_3$ and LPG (and ethane) | T | Temperature |
| LDME | Liquefied dimethyl-ether | Td | Design temperature |
| LH2 | Liquefied hydrogen | US | United States |
| LHC | Fuel group: All fuels that are liquid at P=1.025 bar and T=50°C | VLGC | Very large gas carriers/ships |
| LNG | Liquefied natural gas | W | World |
| LNH3 | Liquefied ammonia | | |

## Purpose and scope

This technology catalogue provides an overview of the different technologies for transporting fuels with specific focus on Hydrogen ($H_2$), Ammonia ($NH_3$), Dimethyl Ether (DME) and Liquid organic hydrogen carrier (LOHC). The catalogue provides cost and performance data for transportation via pipeline, truck and ship.

The document include catalog on transport via:
1. Pipeline
2. Trucks
3. Ships

These Subsections are preceded with this introduction section that include:

1. Description of the different types of fuels and their key properties (See section *Properties* & *Short fluid description and Grade*)

2. Grouping fuels into (Section *Transport form – chemical phase*):
   - Liquid fuels (**LHC**)
   - Fuels that are liquefied @ 20 bar (**L20**)
   - Fuels that require extreme cooling to liquify (**H2NG**)

   There exist many different fuels (see Table 12). To avoid having to treat each fuel separately, the above three fuel groups have been defined. These groups are used to identify which transport form/phase is possible/optimal and thereby which elements that are needed in the transport chain.

3. Advantages and disadvantages of different transport forms (i.e. pipeline, truck, train and ships) (Section *Transport unit – pipeline, truck, train or ship*)

4. Material of construction, i.e. steel grade needed for handling the different types of fuels (Section *Material of construction*)

5. Safety issues (Section *Safety*)

6. Overall transport chain (Section *Transport chain - logistic and infrastructure*) giving an overview of the elements that must be included in the entire transport chain

7. Energy loss - overview of different type of energy losses and how they can be predicted (Section *Energy losses*)

8. Possible elements of the transport chain:
   - Conversion to/from hydrogen carrier (Section *Conversion to/from carrier (LOHC)*) (only for $H_2$)
   - Conversion to liquid phase by cooling (Section *Convert to liquid phase by cooling*)
   - Compressor (Section *Compressor*)
   - Pumps (Section *Pumps*)
   - Fiscal metering (Section *Fiscal metering stations*)
   - Storage tanks (Section *Storage tanks*)

   These sections include losses and costs for the different elements.

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

## Properties

### Key properties

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

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

In Table 12, the following properties are given:

1. **Energy density:** The energy density listed is per mass. This can be converted to energy density per volume by multiplying with the density which is given too. The mass- and volume-based energy density is plotted in Figure 6.

2. **Freezing point and boiling point/distillation curve:** The freezing point give the solidification point while the boiling point/distillation curve give the point/range where it vaporizes. For single components (i.e. $H_2$, $NH_3$, MeOH, etc.), freezing and boiling points are single point, while for mixtures (LPG, gasoline, jet fuel, etc.) it's ranges. These properties give the chemical phase (solid, liquid, gas) that a given fuel will take at ambient pressure (1.025 bar).

3. **Flash point, autoignition point and flammability/explosion limit:** These properties are ignition and safety related properties. Flash and autoignition point give the lowest temperature at which it ignites with and without an ignition source. The explosion limit gives the fuel concentration range in air where it will burn/explode in the presence of an ignition source.

| Fuel types | Fuels | Energy density - LHV (MJ/kg) | Heat of condensation (@ boiling point) (MJ/kg) (% of LHV) | Temperature, C | | | | Flammability/Explosion limit, % (LFL/LEL) / (UFL/UEL), % | Molecylar weight, kg/kmole | Density, g/l, kg/m3 (at Amb.) (Liquid dens. @ Pboil) | Chemical/CNO |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Freezing point | Boiling point/ Distillation curve | Flash point | Autoignition | | | | |
| $H_2NH_3$ | Hydrogen | 120 | | -259.2 | -253 | NA | 560 | 4/75 | 2 | 0.0899 (70.9) | H2 |
| | Ammonia | 19 | 1.37 (7.4%) | -77.73 | -33.4 | 132 | 651 | 15/28 | 17 | 0.73 (620/7 bar) | $NH_3$ |
| Hydrocarbon mixture | NG | 47 | | -182 | -163 | -188 | 600 | ~5/16 | 16-18 | 0.76 (657) | C1 |
| | LPG | 46.6 | 0.43 (0.9%) | -188 | -43 | (-60)-(-100) | 410-580 | 1.8/9.6 | 42-56 | ~ 2.4 (540) | C3-C4 |
| | Petrol/benzin/ gasoline | 43 | | <-40 | 30-210 | -43 | 280 | 1.4/7.6 | ~72 | ~ 780 | C4-C12 (typical C7-C11) |
| | Diesel | 43 | | <-6 | 150-360 | 52-96 | 210-230 | 0.6/5.5 | 198-202 | 800-850 | C12-C20 |
| | Vegetable oil (HVO) | 44 | | <-10/-40 | 180-320 | > 55 | 424 | 4/33 | ~ 250 | ~ 780 | C15-C18 |
| | Heavy fuel oil (HFO) | 39 | | NA | 150-750 | > 50, 65-80 | >400 | NA | mean=240, 50-1800 | ~ 980, >900 | tyical C20-C50 |
| | Marine gasoil (MGO) | 44-45 | | >-40 | 150-500 | 60-85 | >250 | 1/6 | 200-300 | 850-870 | <C35 |
| | Jet-fuel (Jet A-1) | >42.8 | | <-47 | 205-300 | 38-66 | >229 | 0.6/4.7 | ~185 | 775-840 | C10-C13, mostly kerosene |
| | Kerosene | 43 | | -47 | 150-275 | 37-72 | 220 | 0.6/4.7 | ~170 | 780-810 | C6-C20 (typically C10-C16) |
| Oxy fuels | Methanol | 20 | | -97.6 | 65 | 11-12 | 385 | 6/36 | 31 | 790 | CH3OH |
| | Ethanol | 27 | | -114 | 78.4 | 16.6 | 363 | 3.3-19.0 | 46 | 789 | C2H5OH |
| | Propanol (Bio-LPG) | 34 | | -126 | 82 | 26 | 371 | 2.1/13.5 | 60 | 803 | C3H7OH |
| | n-Butanol | 33 | | -89.8 | 118 | 35 | 343 | 1.4/11.2 | 74 | 810 | C4H9OH |
| | DME | 29 | 0.47 (1.6%) | -141 | -24 | -41 | 350 | 3.4/27 | 46 | 2.11 (668) | C2H6O |
| | Bio-Diesel (FAME) | 38 | | (-16)-16 | 340-360 | 173 | 261 | NA | ~296 | ~ 880 | C16-C81, Ester |
| LOHC | DBT: Dibenzyltoluene | | | <-31.8 | >250 | 190-210 | 500 | NA | 272 | 1029 | C21H20 |
| | HDBT: Perhydro-Dibenzyltoluene | | | -34 | ~390 | ~200 | | NA | 291 | | C21H38 |
| | FA: Formic acid | 6 | | 8.4 | 100.8 | 69 | 601 | 14/34 | 46 | 1220 | CHOOH |
| | MET: Methanol | 20 | | -98 | 65 | 11-12 | 385 | 6/36 | 31 | 790 | CH3OH |
| | TOP: Toluene | 40.6 | | -95 | 110.6 | 6 | 480 | 1.1/7.1 | 92 | 867 | C7H8 |
| | Methylcyclohexane | 43.3 | | -126.3 | 101 | 79-87 | 540 | 0.9/5.9 | 98 | 770 | C7H14 |

**Table 12: Key fuel properties.**

## Energy density

The energy density for various fuels are shown in Figure 6.

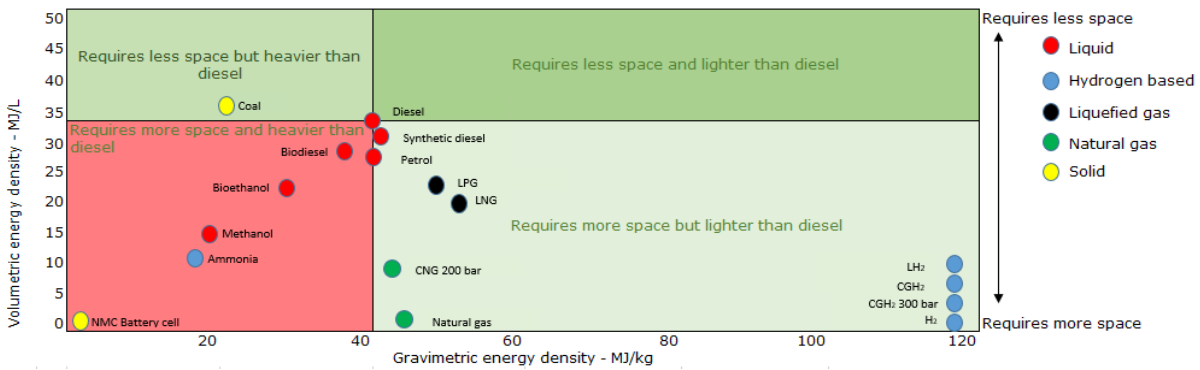



**Figure 6: Energy density for various fuels**

## Phase curve

In Figure 7 the gas-liquid phase curve is represented for various fuels. Thus, the fuel is liquid on the left-hand side of the curve and gas on the right-hand side. The red line represents ambient condition (pressure is 1.025 bar and temperature is between -50 °C and +50 °C). This red line express which phase the fluid is if not exposed to any cooling or pressurization. At 20 bar (the purple line) the majority of fuels (all except for hydrogen, methane and ethane) are liquids.

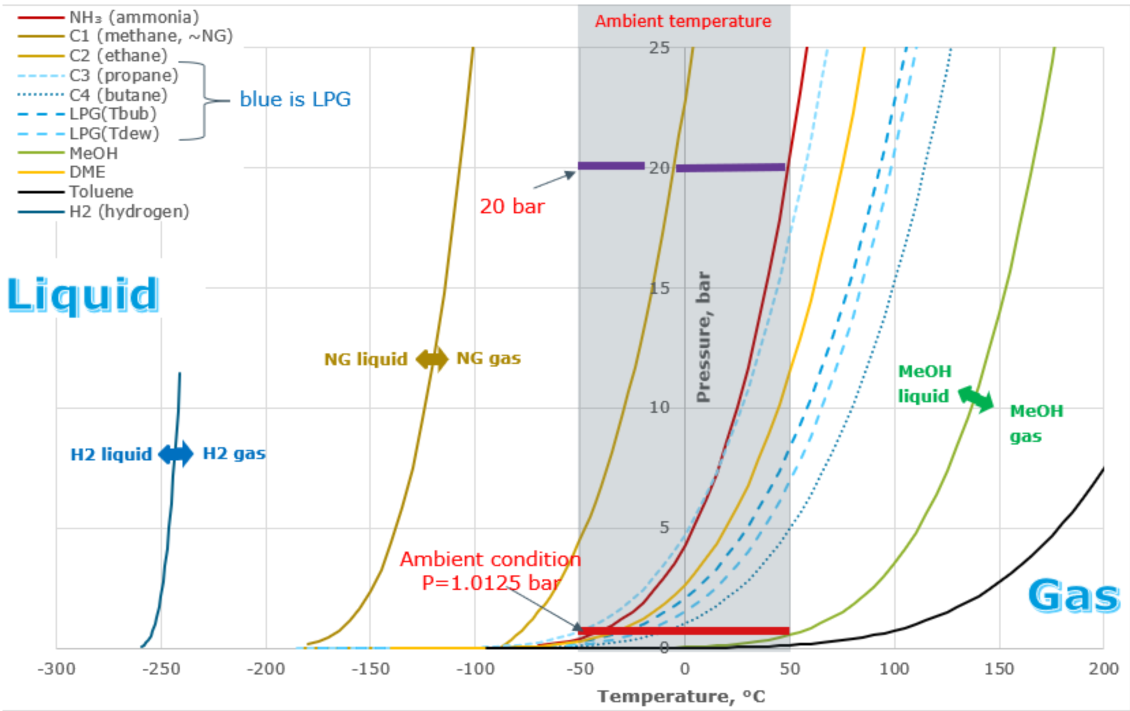



Figure 7: Phase curve for various fuels. Toluene is representative for LOHC which all are liquid at ambient condition. All hydrocarbon mixtures above C5 and all alcohols are below the MeOH curve

## Short fluid description and Grade

### Hydrogen ($H_2$)

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

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

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

### Ammonia ($NH_3$)

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

Typical product specification ref. 25:

1. >99.5 wt % $NH_3$

2. 0.2-0.5 wt % Water
3. max 5 ppm oil

Refrigerant grade ammonia ref. 28

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

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

### Dimethyl ether (DME)

Dimethyl ether (DME, CH3OCH3) is colorless, non-toxic and highly flammable.

Typical product specification

- 99.7 DME
- Rest is MeOH

## Transport form – chemical phase

Within this catalogue, fuels are divided into three groups (see Table 13).

| Group | Description | Include | Transport form | Transport options | | |
|---|---|---|---|---|---|---|
| | | | | Pipeline | Truck/ train | Ship |
| 1<br>LHC | Liquid @ ambient condition<br>(see ***Liquid fuels (LHC)***) | • HC where CNO≥5<br>• All alcohols<br>• All LOHC | Liquid<br>P=few bars, T=Amb. | yes | yes | yes |
| 2<br>L20 | Liquid @ P=20 bar<br>(see ***Liquid at ≥ 20 bar (L20) - NH3, DME and LPG***) | • $NH_3$<br>• LPG<br>• DME<br>• (Ethane) | Pressurized Liquid<br>P=10-30 bar, T=Amb. | yes | yes | yes |
| | | | Cooled liquid<br>P=few bars, T~ (-25)-(-45) °C | no | yes | yes |
| 3<br>H2NG | Require extreme cooling to liquify<br>(see ***H2 and NG***) | • $H_2$<br>• Methane/NG | Pressurized gas<br>NG: P=60-80 bar, T=Amb<br>$H_2$: P=60-140 bar, T=Amb | yes | yes | no |
| | | | Cooled liquid[2]<br>NG: P=few bars, T~-163°C<br>$H_2$: P=few bars, T~-253°C | no | yes | yes |
| | | | Carrier (only $H_2$)<br>P=few bars, T=Amb. | yes | yes | yes |

**Table 13: Transport groups, which fuel belong to each group, possible transport form/phase and possible transport options**

Group 1 (LHC) is liquid at ambient condition. Group 2 and 3 fuels are converted into the more energy dense transport form either via pressurization, cooling or reaction with a carrier[3] (latter only relevant for $H_2$). The advantages and disadvantages for each of these packing methods are listed in Table 14 below.

[2] Might be a combination of cooling and pressurization

[3] **See definition/description in 0 and**
Table 15

| | Pressurized | Cooled | Carrier[3] (only $H_2$) |
|---|---|---|---|
| Advantages | 1. Low compression loss<br>2. Low transportation loss | 1. High volumetric energy density compared with compressed gas | 1. Higher volumetric energy density compared with both CH2 and LH2<br>2. Stored at ambient condition<br>3. Existing infrastructure can be used<br>4. Neglectable transport and standby loss<br>5. Long term storage without loss<br>6. Safety – less flammable fluid |
| Disadvantages | 1. Low volumetric energy density requiring many tours if transported with trucks/ships.<br>2. Cost intensive as high amount of steel is required due to the high pressure (thick tank walls) | 1. Capital cost of installing refrigeration/cryogenic unit<br>2. High conversion loss<br>3. Normally high loss when transferring fluid from one vessel to another (all surfaces must be kept cold)<br>4. Boil off (or cooling or highly isolated) under transportation/standby | 1. Capital cost of installing conversion unit<br>2. High conversion loss<br>3. Extra transport fuel as weight of carrier must be transported too (both forth and back) |

**Table 14: Advantages and disadvantages for different methods of converting group 2+3 into more energy dense transport form.**

## Liquid fuels (LHC)

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

1. All hydrocarbons with carbon number (CNO) larger and equal to 5 (gasoline, diesel, HFO, MGO, Jet fuels, etc.)
2. All alcohols (Methanol, Ethanol, Propanol, etc.)
3. All liquid organic hydrogen carriers (LOHC) (see examples in Table 12)

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

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

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

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

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

### $H_2$ and NG

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

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

Mobile transport: NG will normally be transported as a liquid. Hydrogen is today mostly transported as compressed gas but liquid transportation exist too. As hydrogen require extreme cooling, its optimal transportation (and storage) form is still under development. Figure 8 gives an overview of different ways hydrogen can be transported/storage.

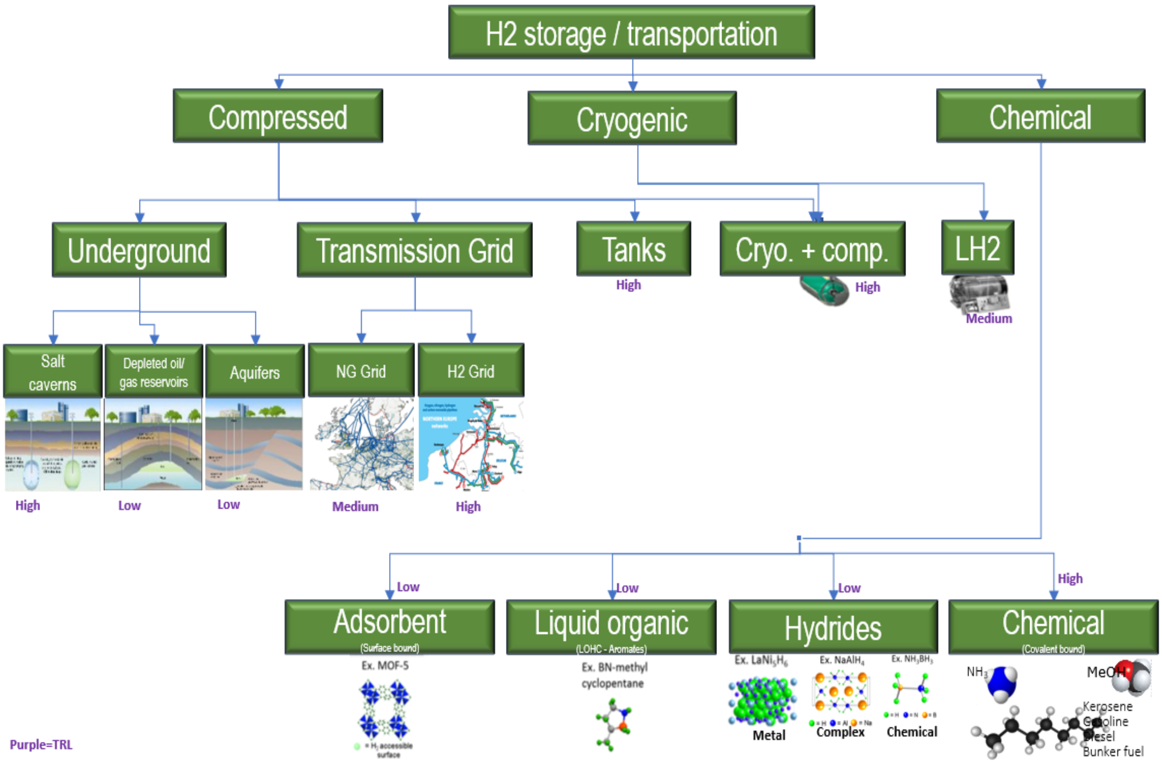



Figure 8: Different $H_2$ storage and transport technologies

For compressed underground and tank storage see ref. 7.

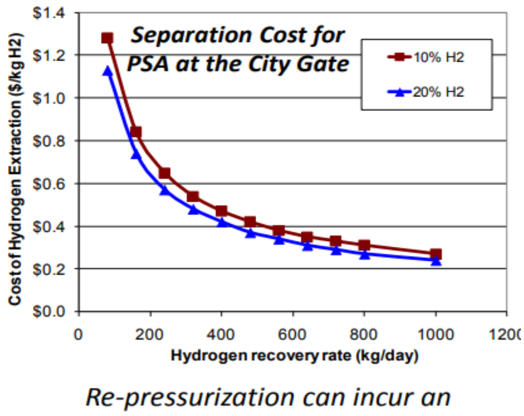



**Figure 9: Separating $H_2$ from NG using PSA ref. 19**

Transport of hydrogen via existing NG-grid: Today no $H_2$ is allowed in the Danish NG-grid. Investigation have been made [ref. 16] and it is expected that 10% hydrogen can be added with minor modifications and more (but still moderate) investment is required to allow up to 20% $H_2$.

The disadvantages of admitting $H_2$ to the existing net is that any users that need pure $H_2$ (or pure $CH_4$[4]) need to separate $H_2$ from $CH_4$ which is expensive. Normally a PSA will be applied for such separation and here the natural gas will come out at low pressure and need to be re-pressurized.

Liquid hydrogen require liquefaction. The energy loss under liquefication process is very high (see *Cryogenic Liquefaction of H2*) meaning that LH2 only is optimal for very long-distance transport.

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

Different types of hydrogen carriers are listed in Table ***15*** together with their advantages/disadvantages.

| | Description | Component (examples) | TRL | Advantages | Disadvantages |
|---|---|---|---|---|---|
| Adsorbent | Solid that adsorb hydrogen on the surface or in the pores of complex materials via intermolecular forces. | Metal–organic frameworks (MOFs), graphene, carbon nanotubes | 1 | Materials can be reused many times<br>Stable materials | Immature technology |
| Ion hydrides | Compounds consisting of hydride ions ($H^+$) and electropositive metals, typically an alkali or alkaline earth metal | LiH, NaH, KH, MgH | 2 | Flexible source of hydrogen<br>Can be stored infinite under dry conditions | Must not be exposed to any moist before the dehydration, pyrophoric<br>Dehydrogenation is strongly exothermic => waste heat |
| Covalent metal hydrides | The hydride is part of complex ions, where hydride is covalent bound to a metal atom | LiBH4, NaBH4, LiAlH4, NH4BH4 | 2 | More stable than ion hydrides | Highly alkaline waste after hydrogen release |
| Metallic hydrides | Hydride is nonstoichiometric bound/adsorbed/absorbed to precious metals and its alloys. Hydrogen is released by heating | Precious metals (Pd, Pt) | 2 | Knowledge available from the Ni-Hydrogen battery technology | High cost as currently made in small quantities and as require >95% purity |
| Liquid Organic hydrocarbons (LOHC) | Liquid organic hydrogen carriers are organic chemical components that relatively easy can be hydrogenated/dehydrogenated. | See Table 12 and ref. 7. | 7 | Transported and handled as liquid fuel are handled today | Many different technologies for releasing hydrogen |
| $H_2$ righ chemical | Non carbon-based compounds that relatively easy can be hydrogenated/dehydrogenated. | $NH_3$, hydrazine | 4-8 | Except for the cracking into $H_2$, mature technology ready for large scale exploration | Toxic<br>Untested as hydrogen supply<br>Very high cracking temperature required<br>$NH_3$ is poison to PEM fuel cell, i.e. no $NH_3$ traces after cracking |

**Table 15: Different type of hydrogen carriers**

[4] Most of todays gas-turbines cannot take larger amount of hydrogen.

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

## Transport unit – pipeline, truck, train or ship

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

| | Advantages | Disadvantages |
|---|---|---|
| Pipeline | • Limit number of intermediate storage/compression stages (Table 19).<br>• Combine transport and storage<br>• Very low OPEX<br>• Very low risk<br>• Can transport large amount of energy much cheaper than electric cables | • High CAPEX<br>• Less flexible than mobile transportation |
| Trucks | • Provide point to point solutions, i.e. limit number of intermediate storage/compression stages | • Risk is higher than pipeline, train and ships<br>• Size limited to max weight, width and length of a truck |
| Trains | • Risk are lower than trucks but higher than pipelines | • No point to point solution – needs other transportation form in both ends<br>• Size limited to max weight, with and length of train carriage |
| Ships | • Less fuel consumption per distance: ship ~0,3 MJ/ton/km, train ~0,6 MJ/ton/km, road ~1.2 MJ/ton/km. Reason is less friction loss due to buoyancy forces.[5]<br>• Size limitation: much larger amount can be transported per trip than on trucks and trains<br>• Social risk (the amount of people that can die if an accident occurs) is much less offshore than onshore (see ***Safety***)<br>• Cheapest option for very long distances | • No point to point solution – needs other transportation form in both ends |

**Table 16: Ways to transport major amount of fluids and associated advantages/disadvantages**

Overall:

1 Truck: optimal for low capacity, short distance, onshore transport

2 Train: optimal for long distance, through desert areas without intermediate consumers, and where onshore route is much shorter than offshore (i.e. across US, Russia and Australia)

3 Ship: optimal for long distance where a valid offshore route exists

4 Pipeline: optimal when larger quantities and/or many consumers

Below a catalogue for pipeline (chapter 0), truck (chapter 0) and ships (chapter 0) are given. Train have been excluded as other transportation forms are normally more optimal in Europe due to either short distance, many intermediate consumers and lot of coastline. An exception is ammonia which is transported via rail from Russia to Europe [ref. 25].


**Figure 10: Train transporting NH3 from Russia to Europe.**

[5] Energy Efficiency of different modes of transportation, James Strickland, 2006

## Material of construction

### Hydrogen ($H_2$)

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

1. High temperature[6] (>150°C, very little <200°C) [ref. 27]
2. Surface irregularities (impurities in the hydrogen and at the surface)
3. Corrosion
4. Electrochemical or chemical surface treatment
5. Cathodic protection

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

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

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

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

**Susceptible material:** ASME B31.12 specify material requirements to hydrogen pipes[7] and material grades that are approved for hydrogen pipes. For design pressures (Pd) <200 barg and design temperatures (Td) <175°C Carbon steel (A 105/A 106) and Micro alloy steel (X42 and X52) is applicable.

[6] Material is normally exposed to hydrogen at high temperature under manufactures (casting, carbonization, coating, plating, cleaning, pickling, electroplating, electrochemical machining, welding, roll forming and heat treatment).
[7] The key material requirements are also listed in ref. 6 and 1.

For Pd>200, high alloy steel (SS-316L) should be used [ref. 6]. X70 may be used subject to evaluation of the hardnability in weld heat affected zones. Within this catalogue, X52 have been used.

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

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

### Ammonia ($NH_3$)

Ammonia is corrosive to:

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

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

Water content in ammonia should be > 0.1 wt %. Research have shown [ref. 8] that presence of water inhibit the formation and growth of SCC (see grade specification under *Ammonia ($NH_3$)*).

Non-ferrous alloys are resistant to ammonia. Minimum requirement for stress yield strength and post-welding treatment are given in IGC Code chapter 17.12. The code also describe how ammonia stress corrosion cracking is avoided.

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

### Dimethyl ether (DME)

Steel piping are suitable for dimethyl ether. Within this catalogue X52 have been applied.

### Liquid fuels (LHC)

Steel piping are suitable for most LHC. Within this catalogue X52 have been applied.

## Safety

Key safety parameters are listed in Table 17. All fuels are flammable with $H_2$ being the most flammable/explosive. $NH_3$ do also have toxicity impact (see section *Ammonia ($NH_3$)*).

**Table 17: Key safety parameters**

| | | $H_2$ | $NH_3$ | DME | LHC/Toluene |
|---|---|---|---|---|---|
| Toxicity | | None | See ***Ammonia ($NH_3$)*** | None | Depend on chemical. Liquid, i.e. leakage do not lead to inhalation. |
| Flammability/ Explosion limit[8], % | Lower (LFL/LEL), Upper (UFL/UEL) | 4<br>75 | 15<br>28 | 3.4<br>27 | 1.1<br>7.1 |
| Flame | | Very difficult to see | Yellow | Blue | Most white + yellow |
| Flash point, C | | NA | 11 | -24 | ≥6 |
| Auto ignition point, C | | 560 | 651 | 235 | 200-500 |
| Ignition energy, mJ | | 0.017 | 680 | 0.29 | >0.2, most ~0.25 |
| Detection limit air | | 25 ppm | 5-50 ppm (smell), ~1 ppm | - | - |

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

### Collision

The probability for collision between mobile transport depend strongly on where the transport is carried out. Generally, the likelihood for collision is much higher in populated areas, i.e. in cities, on train stations or in harbours. Additionally, the likelihood for collision on road is much more likely than collision with train or ships. Contradictory, if a collision occurs, then probability of tank rupture, and leak of large amount, is much higher from thin walled tank that carry cooled liquid (which is the most common liquefaction method on ships) than for thick walled tank that carry pressurized liquid [ref. 13].

### Loading/unloading

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

It must be ensured that all loading systems/tanks are emptied for oxygen before exposed to fuels. Any purge with inert gas to remove oxygen must subsequently be vented to prevent contamination of fuel with inert gas. Tank-purge can be avoided if tank is only used for one fluid type and the tank is kept at slightly overpressure to prevent ingress of air. This is common for CH2 tube trailer tanks.

If loaded with refrigerated/cryogenic liquid, the loading system/tanks must either be pre-cooled or loading must be slow to prevent uncontrolled pressure rises and unsafe temperature gradients. Due to the sub-zero boiling points at atmospheric pressure of LPG, $NH_3$, DME and $H_2$, the refrigerated liquids that are entering tanks and piping which are at ambient temperature and pressure immediately begin to boil. Boiling and evaporation will continue until the materials reaches the liquid temperature. This initial boiling will cause a rapid pressure increase in the loading system. The pressure attained will depend on the quantity of liquid and the heat available for evaporation. Care should therefore be taken

[8] Gas to air ratio

to introduce liquid into non-cooled tanks sufficiently slowly to avoid an uncontrolled pressure rise. The initial boiling will also cause local cooling of the tank structure, with the risk of thermal stresses of the materials. Spray cooling[9] is essential for very cold cargoes.

### Leakage

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

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

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

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

### Sectionalization

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

### Hydrogen ($H_2$)

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

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

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

## Ammonia ($NH_3$)

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

| Conc. ppm | Exposure period | General effect |
|---|---|---|
| 5-50 | Max 8 h | Odor, detectable by most persons,<br>Mild discomfort |
| 50-80 | 2 hours<br>Exposure for longer periods not permitted | Perceptible eye and throat, |
| 100 | | Nuisance eye and throat irritation |
| 140 | 2 hours | Serve irritation, need to leave exposure area |
| 134 | 5 min | Tearing of eyes, eye-, nasal-, throat- and chest irritation |
| 500 | 30 min | Upper respiratory tract irritation |
| 700 | <1 h | No serious injuries and repeated exposure produce no chronic effect |
| 700-1700<br>5000-2000 | Can be fatal after 30 min<br>Can be fatal after 15 min | Convulsive coughing, Severe eye, nose and throat irritation, Incapacitation from tearing of eyes |
| 5000-10000<br>>10000 | Rapidly fatal (within min)<br>Promptly lethal | Respiratory spasm, Rapid asphyxia |

**Table 18: Ammonia toxicity exposure levels ref. 14, 25 and 8.**

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

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

Safety measures for handling ammonia include:

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

**Figure 11: NH3 leakage - Panaji**

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

## Odorization

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

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

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

## Transport chain - logistic and infrastructure

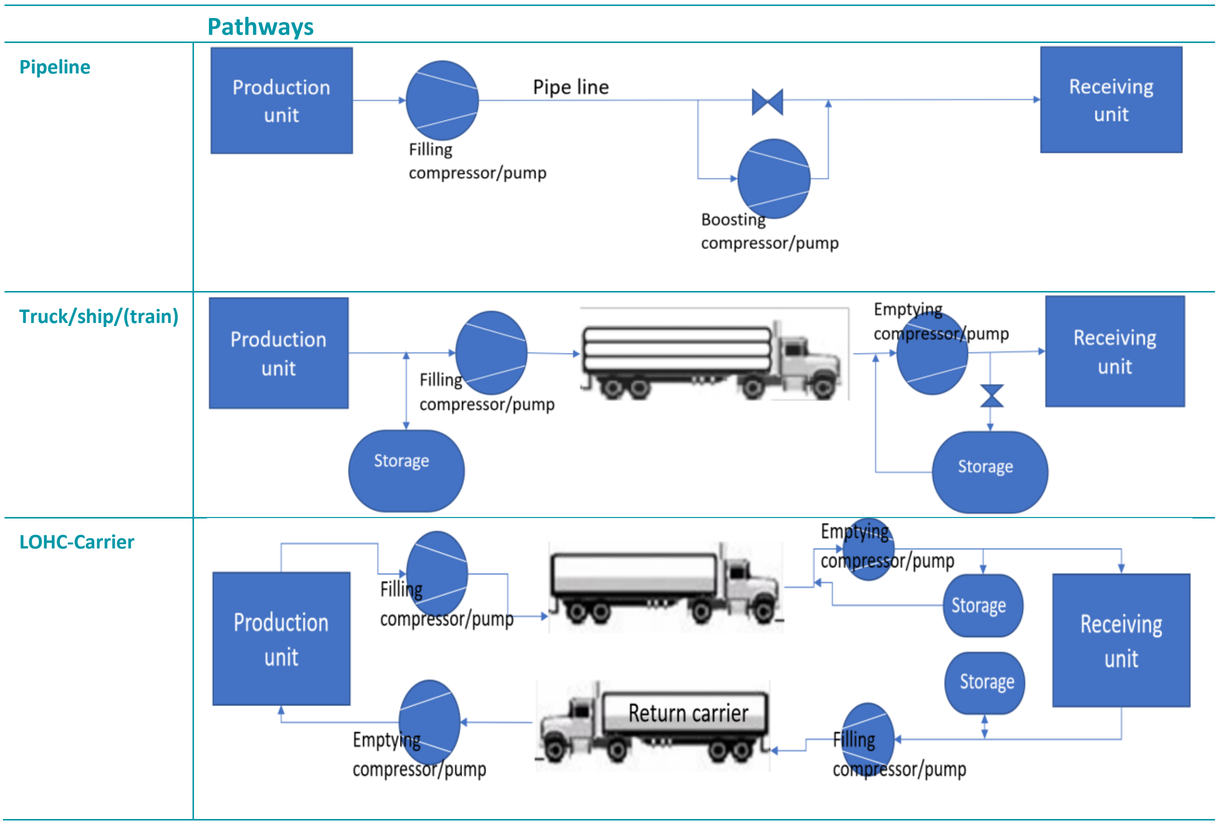



**Table 19: Infrastructure for the different transportation solutions**

Table 19 give overall units need for the different transport method.

While filling compressor/pumps are used to transfer the fuel from the production unit to the transportation unit, emptying compressor/pump is used to transfer the fuel from the transport unit to the receiving unit. Emptying compressors/pumps may for liquid fuels be replaced with gravity (see Figure 20).

**Pipeline:** Key elements are the pipeline, filling and boosting pressurization units (see detail description in *Elements in pipe transmission net*). Boosting compressor is compressor/pump substations along the pipeline that boost the pressure to compensate for pressure drop along the pipeline.

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

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

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

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

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

Hydrogen battery

**Figure 12: Hydrogen storage, transportation and fuel tank.**

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

## Energy losses

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

1. **Conversion to/from a carrier** (only for hydrogen) (see *Conversion to/from carrier (LOHC)*)

2. **Cooling losses** – losses in conversion to liquid phase via cooling
   2.1. Refrigeration of $NH_3$, LPG and DME (see *Refrigeration of $NH_3$, LPG and DME*)
   2.2. Cryogenic liquefaction of NG and $H_2$ (see *Cryogenic Liquefaction of NG* and *Cryogenic Liquefaction of H2*)

3. **Pressurization losses** – shaft power and interstage cooling losses within filling, boosting and emptying compressors/pumps
   3.1. Compression losses (for CNG and CH2) (see *Energy loss – reciprocating H2 compressor*)
   3.2. Pumping losses (for LH3, LPG, LDME, LNG, LH2) (see *Pumps*)

4. **Fuel for propulsion** (for truck, train and ships): Fuel consumption depend on weight due to increased resistance and increased force needed when accelerating.

Trucks:

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

Table 20: Fuel consumption - ref. 21

As a truck is full one way and empty the other way, 19 MJ/km is used as average (19 MJ/km is ~50% load). For CH2, the fuel is carried in thick walled tubes, and for LH2, the fuel is carried in a double walled tank. Thus, for CH2 and LH2, 24 MJ/km have been used as an average as the fuel-tanks have a higher weight why the transported fuel per truck is lower.

Ships: The fuel consumption per day of a ship can be described the Barras formula[10]:

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

[10] Barras (2004): Ship Design and Performance for Masters and Mates

Where

W=ship´s displacement (total weight) in tons
v= ship´s speed in knots (typically between 12-14 knots)
Fc= Fuel coefficient (Fc=120.000 for diesel engine)

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

**Equation 1**

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

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

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

   - LH2: 2-3 %/day for small portable $H_2$ containers and down to 0.06%/day for large. Typical boil-off is ~0.1/day [ref. 18]
   - LNG: Typical 0.15-0.6 %/day on ships

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

6. **Leakage:** Leakage is assumed negligible

7. **Heating before depressurization** (only for CNG): On NG transmission pipes, there is additional losses associated with depressurization as NG must be heated before depressurized. For hydrogen, heating before depressurization is not needed as hydrogen do not cool upon depressurization when >-150 °C.

8. **Odor removal** (only for CNG): Odor is often added to NG net. Thus, losses are associated with removing the odor. As per discussion in section *Odorization*, odor is not considered for hydrogen transmission pipes

## Conversion to/from carrier (LOHC)

LOHC (liquid organic hydrogen carrier) are organic hydrocarbon liquids with hydrogen "adsorbing" capabilities (see description in
Table 15).

Conversion and reconversion losses today are 30-40 %. Theoretical possible is 18% and potential obtainable minimum loss is 25% [ref. 7].

## Convert to liquid phase by cooling

Figure 13 gives an illustration of the steps and losses involved in conversion and transportation as liquefied fuel. The losses in liquefaction can in principle be recovered. However, as the liquefaction and regasification will be at two different locations, the calories extracted from the liquefaction will normally be loss.

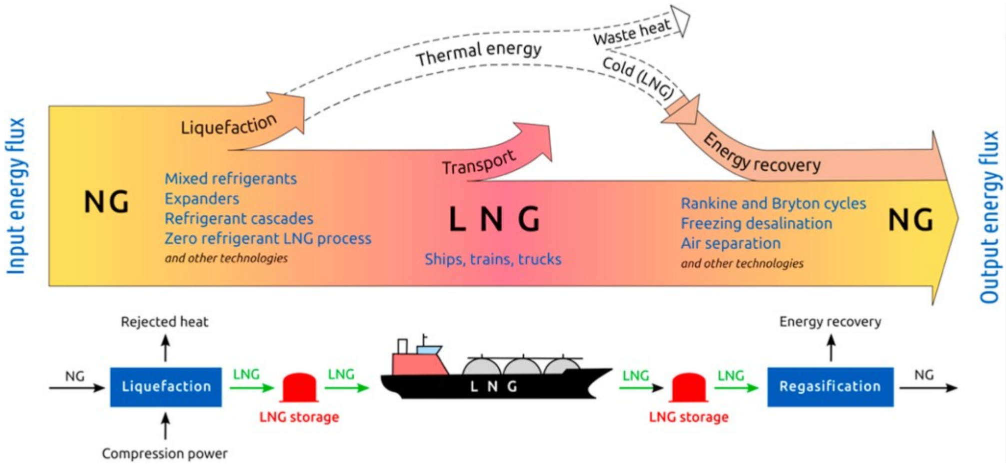



**Figure 13: Illustration of steps and losses in transport of LNG. The other liquefied fuels include the same steps [ref. 11]**

### Refrigeration of $NH_3$, LPG and DME

The energy removed by the liquefaction is the energy required to cool to boiling point plus the energy required for condensation. For $NH_3$, LPG and DME, the energy removed by the condensation is the dominating term. Thus, an estimate for the energy removed by the refrigeration (i.e. the % energy loss associated with refrigeration) is given in Table 12. I.e. for ammonia it is ~7.4 **%** of the LHV, while for LPG it is ~0.9% and for DME is ~0.47 % of the LHV.

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

### Cryogenic Liquefaction of NG

According to ref. 10, the energy loss associated with liquefaction of NG is between 4-7%.

### Cryogenic Liquefaction of $H_2$

The loss in the liquefaction process is between 25-45%, strongly depend on the capacity of the plant (see Figure 9). The theoretical possible minimum loss is 18% [ref. 22]

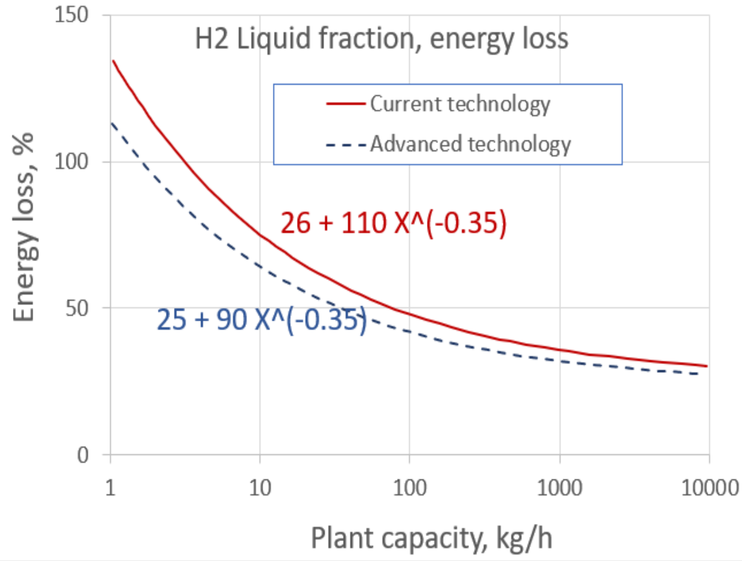



Figure 14: Energy loss associated with liquefaction of H2 [ref.22]

Hydrogen exist in two forms. At very low temperature it is para- $H_2$ while at ambient ~75% is ortho- $H_2$. The transition from ortho to para is very slow and releases significant amount of heat (527 kJ/kg) [ref. 18]. Thus, liquefaction of hydrogen, i.e. transferring $H_2$ (mainly ortho- $H_2$) to LH2 (para- $H_2$) must be done over a catalyst ensuring all is para- $H_2$ before transportation/storage of LH2. If not, 30% of the hydrogen will boil off within two days if stored in full cryogenic tank.

## Compressor

Only $H_2$ compressors are covered within this catalogue.

### Types - hydrogen compressors

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

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

Of reciprocating compressors, the following types exist:

1. Metal piston (free or crankshaft piston)
2. Diaphragm piston
3. Ionic liquid piston (do not require lubrication)

Future alternatives to reciprocating compressors may be the ones listed in Table 21.

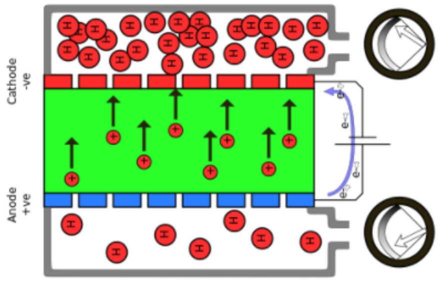
| Compressor type | Description |
|---|---|
| Hydride Compressor | Compressors where $H_2$ is adsorbed by a hydride at ambient conditions. The absorbent is then blocked in and heated whereby the pressure will increase. Compression ratio >20 and final pressure > 1000 bar is possible. However, the product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

Table 21: Hydrogen compressors under development

## Energy loss – reciprocating $H_2$ compressor

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

Shaft power required for compression are given in Figure 10:

1. Adiabatic compression (blue curve): Have no interstage cooling – represent maximum losses
2. Isothermal compression (green curve[11]): Have infinity number of interstage cooling – represent minimum losses, i.e. the ideal compressor

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

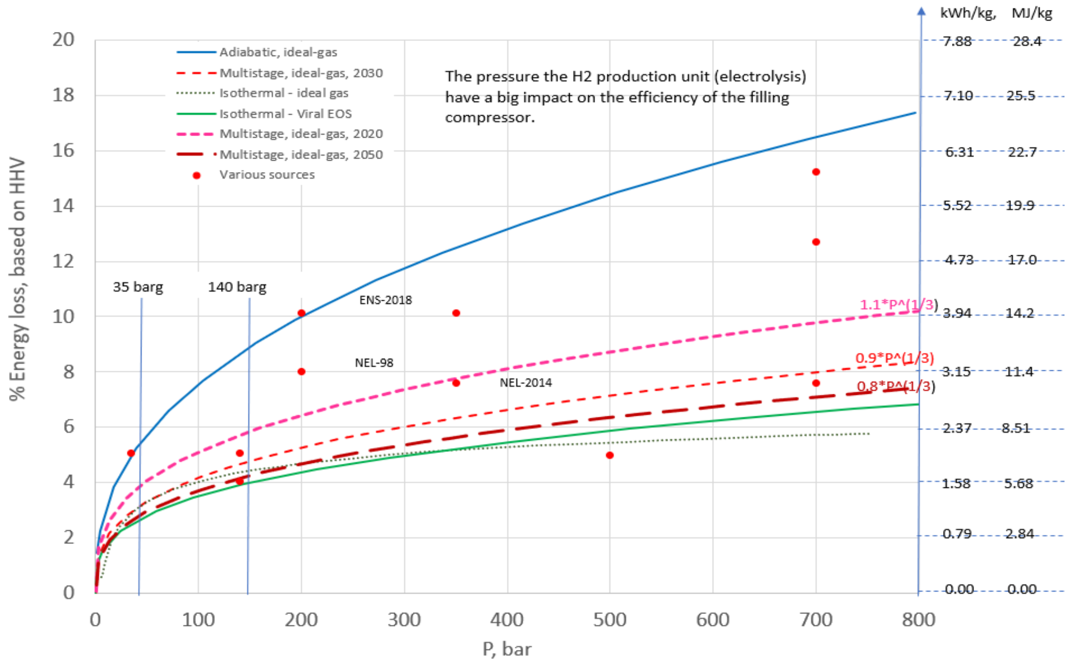



**Figure 15: Energy loss for adiabatic, multistage with interstage cooling and isothermal compression (reciprocating H2 compressors). Points from various sources have been added. Numbers along the secondary y-axis are absolute loss.**

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

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

The following formula is used in this catalogue to calculate compression power loss (Pin=suction pressure [bar], Pout=discharge pressure [bar], A=1.1 in 2020, 0.9 in 2030 and 0.8 in 2050 as per Figure 10):

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

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

| **Calculation example** | | |
|---|---|---|
| Pin, bar | 35 | Suction/inlet pressure |
| Pout, bar | 140 | Discharge/outlet pressure |
| A-factor | 1.1 | A=1.1 (2020), 0.9 (2030), 0.8 (2050) |
| Loss % | 2.1 | =A*(Pout$^{1/3}$-Pin$^{1/3}$) |
| Loss, kWh/kg | 0.8 | =Loss%/100%*39.42 kWh/kgH2 |
| Loss, MJ/kg | 3.0 | =LosskWh/kg*3.6 |

**Table 22: Calculate compression loss compressing $H_2$ gas from 35 bar to 140 bar**

As per Figure 10, the compressor operation cost can be lowered substantially by:

1. **Increasing the suction pressure:** Increasing the pressure in the $H_2$ production unit (electrolysis) will have a huge impact on lowering the operation cost of the compressor as the first steep part of the curve will be cut of
2. **Increasing the number of stages:** Increasing the number of compression stages, and thereby approach the isothermal operation (green line in in Figure 10) will increase the compressor-efficiency. Additionally, multistage pressure level will also enable optimization with respect to the discharge pressure such that gas is only compressed to the current discharge pressure (the discharge pressure will be increasing when filling a tank on a truck/ship and will vary if using pipe-net as buffer/storage)

### Cost – hydrogen compressors

Internal tool has been used for cost estimation of compressors. Estimated cost of filling (35-140 bar) and booster (40-140 bar) compressor is given in Figure 19.

## Pumps

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

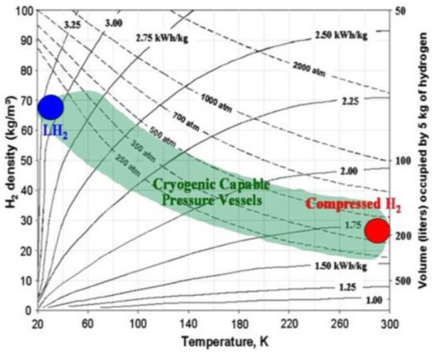
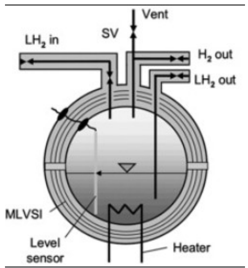
## Fiscal metering stations

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

## Storage tanks

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

In Table 23, typically storage form is given for $H_2$, $NH_3$, DME and LPG. CAPEX for storage pressurized (up to 20 bar) and refrigerated tanks (down to -33 °C) is given too.

<table>
<tr><th></th><th>Pressurized storage</th><th>Pressurized and cooled storage</th><th>Cooled storage</th></tr>
<tr><td>$H_2$</td><td>P=165–550 bar,<br>T=Amb.<br><br>Thick walled metallic (Type I) or composite reinforced tank (Type II, II, IV)<br>
<br>See cost and further description in ref. 7</td><td>
<br>Red is CH2, Blue is LH2 and green is a combination of the two.</td><td>T=-253°C,<br>P≤3.5 bar<br>
</td></tr>
<tr><td>$NH_3$, DME, LPG</td><td><100 ton,<br>T=Amb., P≥20 bar<br></td><td>100-1000 ton,<br>T=0°C,<br>few bars<br></td><td>>10000 ton, up to 40000 t<br>T=-33 °C, P=atm.<br>
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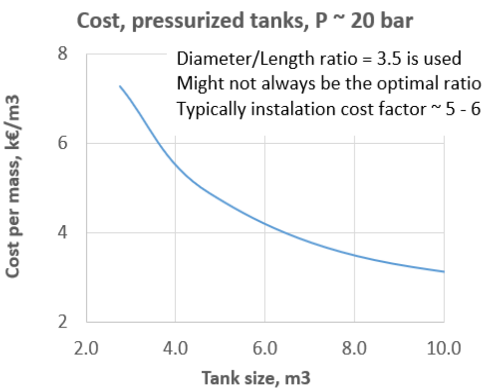
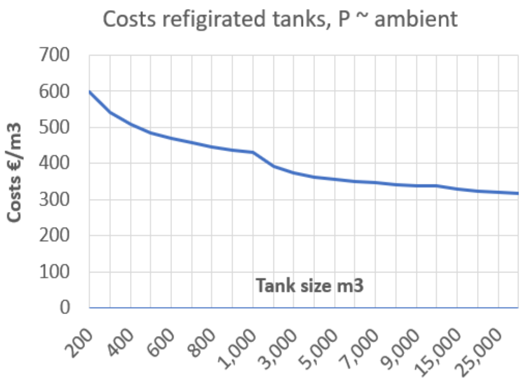
<tr><td></td><td colspan="2">
</td><td>
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</table>

**Table 23: Typical storage form vs fuel and transport phase**

## Examples - full transportation chain

This chapter provide examples where the transport loss and the cost is calculated.

Color codes for all the calculation examples are:

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

### Pipeline – CH2 calculation example

| Pipeline - CH2 | | |
|---|---|---|
| Fixed O&M - % of CAPEX: | 4 | |
| WACC, % | 5 | |
| Fuel: | CH2 | HHV= 142 MJ/kg |
| Transport distance: | 100 km | |
| Transport capacity: | 100 MW HHV | |

| | Power/fuel input | | | | | | CAPEX | | | life-time | CAPEX + Fixed O&M | O&M | | | Tot. Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | % | % 1000km | MW | GJ/t | €/t | k€/y | k€/MW | €/(km*MW) | M€ | y | k€/y | €/t | €/(km*t) | k€/y | k€/y |
| Filling compression, Pin=35 -> Pout=140 bar, A=1.1 | 2.1 | | 2.1 | 3.0 | 33 | 733 | 48 | | 4.8 | 20 | 402 | | | | 1135 |
| Metering + Scraper trap | | | | | | | | | 5.2 | 20 | 434 | | | | 434 |
| Pipeline (Pipe + Booster comp. + Isolation stations) | | 7.5 | 0.8 | 1.1 | 11.8 | 261 | | 2559 | 26 | 50 | 1458 | | | | 1719 |
| **Total** | | | **4** | | | | | | **36** | | **2294** | | | | **3288** |
| | | | | | | | | | | | | | | €/t | **148** |

| | |
|---|---|
| Transort velocity, m/s | 7.0 |
| Transport time, h | 52 |
| Mass flow, TPD | 61 |
| Energy flow, MW HHV | 100 |
| Transported per y, TPA | 22224 |
| Power cost, €/GJ | 11 |

**Table 24: Calculation example - Pipeline CH2 - small pipe**

This example shows the cost and losses associated with a small 100 km pipeline for transporting 100 MW $H_2$ (could be a branch off pipe to a fueling station). The example is comparable with the example in section *Truck – CH2 calculation example*, where truck transport of the same capacity is calculated.

The red numbers are obtained as follows:

1. Filling compression loss (=2.1% of MW $H_2$): See calculation in Table 22.
2. Booster compressor loss (=7.5 % of MW $H_2$), CAPEX for filling compressor (=48 k€/MW), CAPEX of metering an scraper trap (=5.2 M€) and CAPEX for pipeline (=2559 €/(km*MW)) are all from appropriate formulas in Figure 19.
3. Velocity (=7.0 m/s) is obtained from formula given in Table 30

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

### Pipeline – CH2 calculation example

| Pipeline - CH2 | | |
|---|---|---|
| Fixed O&M - % of CAPEX: | 4 | |
| WACC, % | 5 | |
| Fuel: | CH2 | HHV= 142 MJ/kg |
| Transport distance: | 500 km | |
| Transport capacity: | 4000 MW HHV | |

| | Power/fuel input | | | | | | CAPEX | | | life-time | CAPEX + Fixed O&M | O&M | | | Tot. Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | % | | MW | GJ/t | €/t | k€/y | k€/MW | €/(km*MW) | M€ | y | k€/y | €/t | €/(km*t) | k€/y | k€/y |
| Filling compression, Pin=35 -> Pout=140 bar, A=1.1 | 2.1 | | 2.1 | 3.0 | 33 | 29328 | 8.8 | | 35 | 20 | 2947 | | | | 32275 |
| Metering + Scraper trap | | | | | | | | | 5.2 | 20 | 434 | | | | 434 |
| Pipeline (Pipe + Booster comp. + Isolation stations) | | 2.5 | 2.5 | 3.5 | 39 | 34575 | | 351 | 701 | 50 | 39945 | | | | 74520 |
| **Total** | | | **6.5** | | | | | | **742** | | **43327** | | | | **107229** |
| | | | | | | | | | | | | | | €/t | **121** |

| | |
|---|---|
| Transort velocity, m/s | 10.1 |
| Transport time, h | 178 |
| Mass flow, TPD | 2436 |
| Energy flow, MW HHV | 4000 |
| Transported per y, TPA | 888964 |
| Power cost, €/GJ | 11 |

**Table 25: Calculation example - Pipeline CH2 - big pipe.**

This calculation example is identical to the above but just for a larger capacity and a longer distance.

Additionally, the example is similar to the calculation in the first table of Table 32. The major difference are

- CAPEX €/(km*MW): is "351" in Table 25 and "333" in Table 32. Reason for the difference is that in Table 32, cost functions of the individual component (pipe, isolation & vent station and booster compressors – i.e. the red, purple and gray curve in Figure 19) is used while the overall cost function (i.e the blue curve in Figure 19) is applied in Table 25.

- A utilization factor of 100% is used here while it is 75 % in Table 32

## Truck – CH2 calculation example

| Truck - CH2 | | Fixed O&M - % of CAPEX: | 5 | WACC, % | 5 | Operation hours per year, h/y | 8000 |
|---|---|---|---|---|---|---|---|
| Fuel: | CH2 | LHV | 120 | MJ/kg | | | |
| Transport distance: | 100 km | Density | 33 | kg/m³ | | | |
| Transport capacity: | 1.5 t/truck | No. Trucks | 14.0 | | | | |

| | Power/fuel input | | | | | CAPEX | | | life-time | CAPEX + Fixed O&M | OPEX (1) | | | Tot. Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | % | MW | GJ/t | €/t | k€/y | k€ / MW | € / km*MW | M€ | y | k€/y | € / m³ | € / km*m³ | k€/y | k€/y |
| Filling compression, Pin=35 -> Pout=350 bar, A=1.1 | 4.2 | 3.8 | 5.0 | 55 | 1219 | 50 | | 4.7 | 20 | 392 | | | | 1611 |
| Loading/unloading (wage + deprecitation) | | | | | | | | | | | 4.1 | | 2761 | 2761 |
| Driving (wage + fuel + deprecitation) | fuel consumption is part of OPEX | | | | | | | | | | | 0.08 | 5388 | 5388 |
| Total | | | | | | | | | | | | | 8149 | **9759** |
| Note 1: Assume 29 €/GJ diesel, 24 MJ/km | | | | | | | | | | DKK/kg | 3.3 | | €/t | **439** |

| | |
|---|---|
| Driving speed, km/h | 60 |
| Loading/unloading time | 4.3 |
| Roundtrip duration, h | 7.6 |
| Trips per year | 1055 |
| Mass flow, TPD | 67 |
| Energy flow, MW LHV | 93 |
| Transported per y, TPA | 22224 |
| Power cost, €/GJ | 11 |

**Table 26: Calculation example - CH2 truck**

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

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

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

Additionally, loading arm (see Figure 20) is missing too, but this is assumed to be neglectable compared with the other costs.

## Ship – LNH3

| Ship - LNH3 | Fixed O&M - % of CAPEX: 5 | WACC, % 5 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Fuel: | LNH3 | LHV= 18.9 MJ/kg | Power/fuel input | | | CAPEX | | | life-time | CAPEX + Fixed O&M | Port cost | | | Tot. Cost |
| Transport distance: | 10000 km | Dens.= 626 kg/m³ | | | | €/m³ | €/t | M€ | | | €/t | | k€/y | k€/y |
| Transport capacity: | 45000 t/tank | | MJ/km | GJ/trip | k€/y | | | | y | k€/y | | | | |
| Storage tanks | Tank vol (10% excess) | 2x 79000 m³ | | | | 300 | | 47 | 30 | 3238 | | | | 3238 |
| Filling/emptying pumps | Vol.flow (duration 24 h) | 3300 m³/h | SP=0.4 MW, 2*24 h | 69.1 | 7.0 | | | 1.3 | 20 | 106 | | | | 113 |
| Loading arms | | | | | | | | 2.5 | 20 | 211 | | | | 211 |
| Piping and foundation (not included here - depend strongly on location) | | | | | | | | | | | | | | |
| Ship | | | 2435 | 36525 | 2582 | | 1750 | 79 | 20 | 6635 | 1.7 | | 682 | 9899 |
| Total | | | | | | | | | | | | | 682 | **10223** |
| | | | | | | | | | | | | | €/t | **25** |

| | |
|---|---|
| Transport velocity, km/c | 580 |
| Loading/unloading time | 3.3 |
| Roundtrip duration, d | 37.7 |
| Trips per year | 9.19 |
| Mass flow, TPD | 1193 |
| Energy flow, MW LHV | 261 |
| Transported per y, TPA | 413533 |
| Power cost, €/GJ | 11 |
| HFO cost, €/GJ | 8 |

**Table 27: Calculation example – Ship – LNH3**

This example gives an overview of the cost associated with LNH3. LNH3 is produced as a liquid why liquefaction of $NH_3$ is not included.

For ships, storage tanks in both departure and destination harbor is requires as well as filling/emptying pumps and loading/unloading pipes.

Cost of refrigerated storage tanks are found in Table 23. The value for ship are (all value come from the technology datasheet for ships):

1. Fuel consumption of 2435 MJ/km
2. CAPEX for ship of 1750 €/t
3. Port cost of 1.7 €/t

# 131 Transport by pipeline

## Brief technology description

### Elements in pipe transmission net

Major elements in a transmission net are (see Figure 12):

1. **Filling pump/compressor:** A filling station is needed to raise the pressure from the outlet pressure of the production unit to the pressure within the transmission net.

2. **Boosting pump/compressor:** Boosting the pressure along the route to overcome friction loss is needed when the pressure drops below the minimum operating pressure.

3. **Isolation valve/vent station:** To seal off segments in case of leakage. The allowable distance between isolation valves will depend on a risk assessment of each section. In populated areas isolation valves are expected more frequently than in rural areas. Typical distance between isolation valves onshore are 10-20 km. Within this catalogue, isolation/vent station for every 20 km have been assumed.

4. **Fiscal metering stations (M/R):** As described in *Fiscal metering stations*, two independent fiscal metering station will most likely be installed after the filling station.

5. **Cathodic protection:** Cathodic protection included as per shown in Figure 12 (green box with CP), i.e. one for filling station, two for each isolation valve/vent station and two for each boosting station.

6. **Scraper traps:** To maintenance/clean the pipeline, a scraper lancer and a scraper receiver is needed (or a valve arrangement will allow for connection of mobile lancer and receivers) in either ends of the pipe.

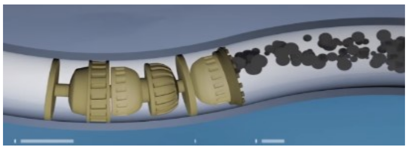


**Figure 16: Scraper (also called pig) used to clean/inspect a pipeline**

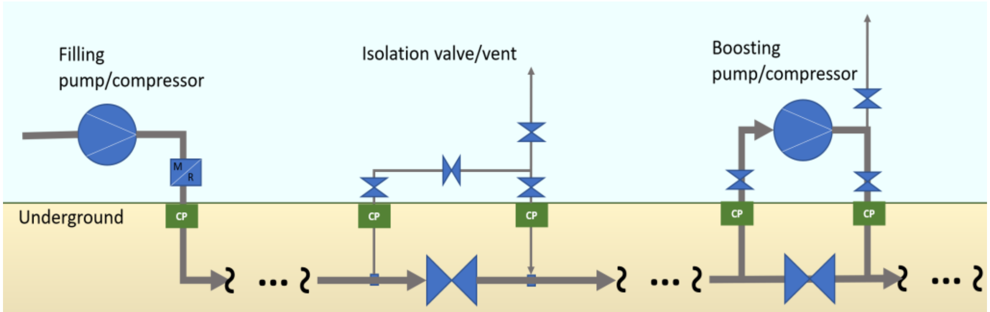



Figure 17: Major elements in a transmission pipe net

Filling compressor, fiscal metering station and scraper traps are installations required at the inlet (and/or outlet) or the pipe. Therefore, these costs have not been included in the "cost per km" estimate. The cost of the filling compressor, the fiscal metering station and the scraper trap are listed in Figure 19.

### Existing pipelines

Some key existing pipelines are listed in the following table.

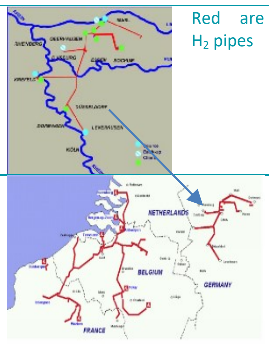
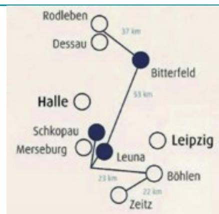
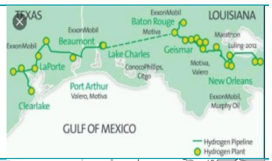
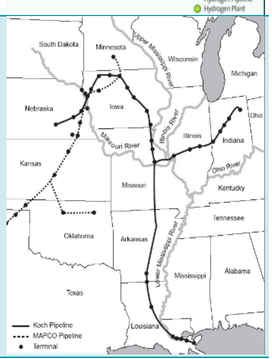
| Fluid | Country/ company | Pd, barg | Mat. | Pipe type | Welding | Dn | km | Year | Ref. | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NG | DK, transmission | 80 | | | | Up to 48" | 900 | | ISO 13623:2017 | | |
| | DK, distribution | 40, 19, 4 | | | | | 17000 | | REDEGØRELSE FOR GASFORSYNINGSSIKKERHED 2019 Energinet | | |
| $H_2$ | US, | <68 | | | | | 450-800 miles | 1930 | Ref. 2 | | |
| | GE (Rhine and Ruhr), AL | 17 20-210 | ≤X42 | ERW | SMAW | 10-12 | 240 | 1938 - | 10000 kg/h ref. 2, 1 and 30] |   | Red are $H_2$ pipes |
| | France, AL | 97 | ≤X52 | ERW | SMAW | | 1000 | 1973-1997 | | | |
| | NL, Gasunie | 100 | | | | ~10" | 237 | | Convert existing NG to $H_2$ 2018 ref. 5, 15 | | |
| | GE, FNB Gas | | | | | | 5900 (1) | | Partly converting existing NG pipelines | | |
| | GE, Central, Linde | | | | | | | | |   | |
| | US, Texas, AL Corpus Christi | 48 (first) 24 (now) | Gr.B (0) | ERW | SMAW | 8 | 100 | 1997 | Originally crude oil pipelines (1940-50). Ruptured because of corrosion in 1998. | | |
| | US, Texas, AL Freeport to Texas city | 51 | X60 (0) | ERW | SMAW | | 54 | 1997 | Originally crude oil pipelines until 1979. Compressor: Lubricating reciprocal + multi-stage filtration for lube oil removal | | |
| | US, Plaquemine-Chalmette ref. 4, 31, AP | | | | | 14 | 240 (965) | 209 | New pipeline connected the two above give a total of 965 km $H_2$ piping. |   | |
| $NH_3$ | US | 17 | CS | | | | ~5000 | | ASTM A333 ref. 15, ref 28 |   | |

**Table 28: Key existing pipes (not all are included)**

Table notes:
Not constructed yet but is planed

See detailed material properties in ref. 1.

### Operation pressure

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

| Fluid | Phase | Pmin/Pmax/Pdesign, barg |
|---|---|---|
| $H_2$ | Compressed gas | 40/140/156<br>40/70/80 |
| $NH_3$<br>DME | Compressed liquefied gas | 20/20 /23<br>13/20 /23 |
| Liquid HC | Liquid | 3 /8 /10 |

**Table 29: Pipe pressures to be considered in this catalogue.**

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

### Converting NG pipes to $H_2$ pipes

It is possible to use existing NG grid, though with some modifications [ref. 16 and 24].

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

Within ref. 8, the cost of converting existing NG-transmission pipes to $H_2$-transmission has been assumed to be equal to 1/3 of cost of new installation.

As the biogas production is relatively extensive in DK and as DK have committed to transport of NG from Norway to Poland (EPII) it is expected that only minor part of the natural gas grid that will be converted to hydrogen transmission grid in the near/medium term.

The existing natural gas transmission net in DK have a design pressure of 80 barg and a min operating pressure of 60 barg.

### Underground pipeline

Pipelines should to the extent possible be underground as:

1. Mitigation of risk: Underground installation reduces the likelihood of damage/vandalism and the risk of explosion in in case of leakage
2. Temperature is less variable: This reduces the expansion and shrinkage of the construction material. Additionally, winterization is not needed if freezing point is below 0°C
3. Do not disfigure the nature and is less prone to protest

Key requirements to underground piping:

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

### Aboveground pipeline

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

Key requirements to aboveground piping:

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

## Input

Input is fluid at operation pressure given in Table 29. The flow is given by the optimal pressure drop and velocities listed in Table 30

## Output

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

## Efficiency and losses

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

For the technology catalogue, a cost optimization has been performed. The dP/dL (dP/dL=pressure drop per km) listed in Table 30 give a good trade-off between CAPEX and OPEX (both for operation pressures at 70 bar as well as for operating pressures at 140 bar). The optimum depends on the length of the pipe, cost of the booster vs cost of the piping material.

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

**Table 30: Optimal/max pressure drop per km (dP/dL, bar/km), Q=duty transported in MW**

## Application potential

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

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

## Typical capacities

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

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

**Table 31: Capacities considered in this catalogue. To convert the energyflow into LHV based flow, multiply with 120/142=0.85.**

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

## Environmental

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

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

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

## Research and development perspectives

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

Improvements and associated cost reduction:

1. Hydrogen compression:
   1.1. Increase the suction pressure
   1.2. Several interstage compressors that is optimized so only compressing to the actual discharge pressure

2. Material of construction:
   2.1. Challenge existing assumptions such as reviewing the limitation on hardness or the belief that higher grades of pipeline steel will be more susceptible to hydrogen embrittlement
   2.2. Approval of newer low alloy steels for $H_2$ services: It is judged that there is room for larger cost reduction due to improved materials ref. 6.
   2.3. Plastic pipes, may especially be optimal for smaller distribution pipes

3. Max operating pressure:
   3.1. Cost calculation within this report shows that the cost advantages of increasing the pressure is limited. However, this will most likely change if stronger alloys are approved for hydrogen service.

4. Design code:
   4.1. Standardisation and development of Eurocodes for hydrogen pipes (i.e. CEN 234 working group or EIGA)

5. Installation cost:

5.1. Position drilling might reduce installation cost substantially: Directional drilling makes pipelines that crosses streams, existing constructions, etc. much cheaper especially in industrial/urban areas.
5.2. Converting NG pipes to $H_2$ pipes will make a major reduction in CAPEX.
5.3. Put a smaller $H_2$ pipeline into an existing NG pipeline

## Prediction of performance and costs

### Investment cost (CAPEX)

The investment cost will include

1. Cost of equipment, piping, piping elements[12] and instrumentations[13]
2. Installation costs
3. Approvals, expropriation, etc.


**Figure 18: Equipment, installation and difficulties associated with installation in larger cities**

For onshore pipelines COWI has made an own estimate of the investment cost based on inhouse experience obtained from engineering and installation of natural gas transmission lines in Denmark. The own estimate is benchmarked against references from the literature.

The following assumptions are used for estimate of pipeline investment cost:

1. A class location safety factor[14] of 0.4 for small pipes and 0.5 for large pipes is used. Pipeline construction material is carbon steel (X52) with polymer coating.
2. The design dP/dL is based on values given in Table 30
3. Cathodic protection is included as per Figure 12.

[12] Insulation valves, vent valves, cathodic protections, etc.
[13] Transmitters for measuring pressure, flow, etc.
[14] Lower class location safety factor means thicker pipes. 0.4 is selected for small pipes (assumed installed in populated areas, i.e. pipe to refueling stations) while 0.5 is selected for large pipes which are assumed to be installed in less populated areas

4. Booster station is added to ensure that the pressure do not drop below the minimum allowable pressure
5. Sectionalisation vales (ESD) with ancillaries every 20 km is assumed. This is uncertain as regulative requirements for $H_2$ pipelines in DK is unclear.
6. Installation cost includes trenching and 8 % for controlled drilling, permitting and environmental investigations
7. Cost factor for engineering and follow-up added (6 to 10% depending on size).
8. Unit cost based on pipeline distance of 200 km. For very short pipelines the unit cost will increase.

Figure 19 shows a system with 35 bar inlet filling compressor and a respectively a 140 bar (lefthand side) and 70 bar (righthand side) operating pressure. In each of the two figures cost and energy loss curves and associated formulas are given depending on the pipeline capacity. These cost and energy loss curves are used to calculate the examples in Table 32 andTable *33* and represent estimated values for 2020.

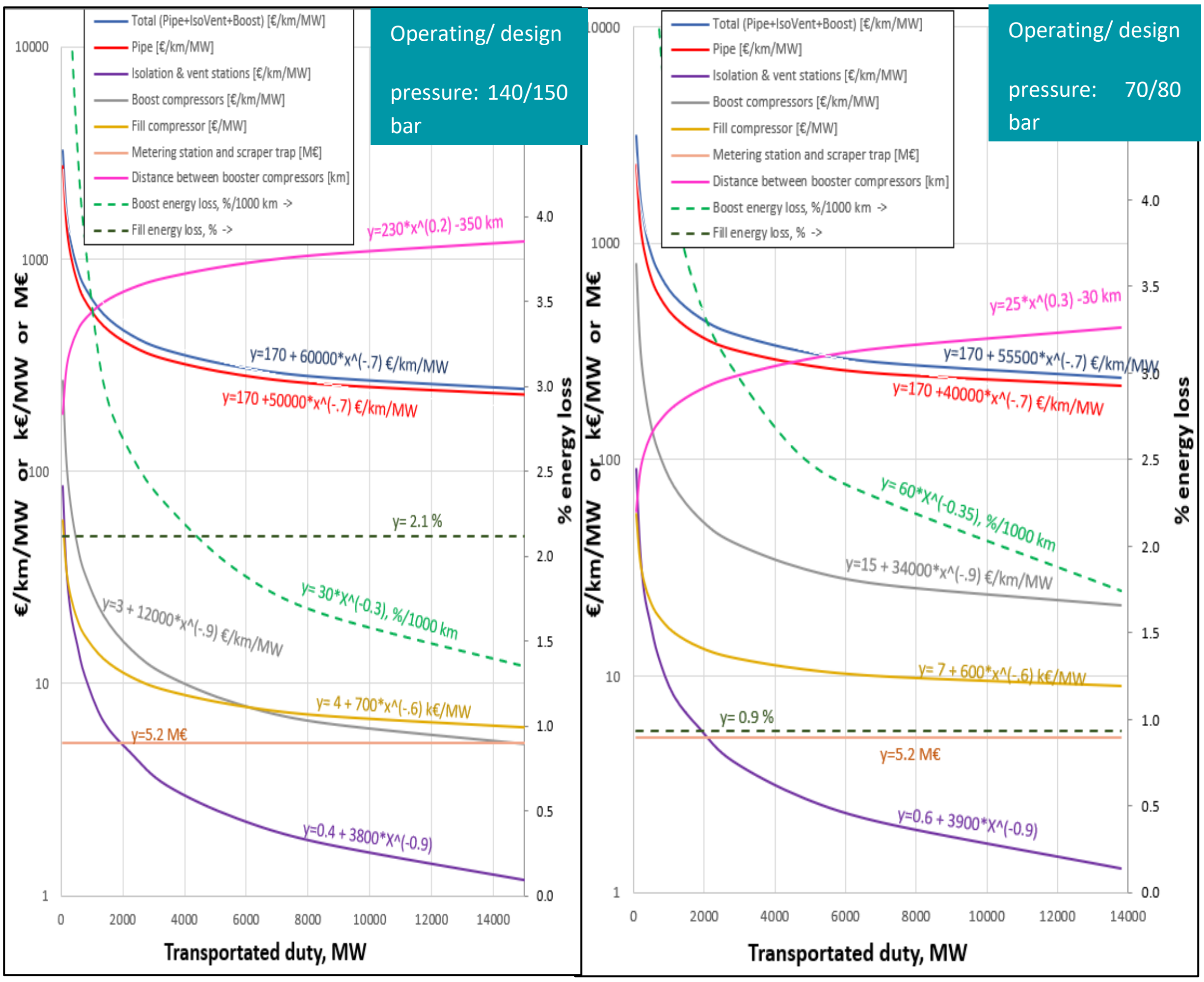



**Figure 19: Estimated CAPEX, compression losses and distance between booster compressor vs. transported duty (HHV) for hydrogen transmission pipes. Examples of how to use the figures are given in tables below.**

The above curves are based on 100% utilization. Cost for reduced utilization is obtained by multiplying the cost per capacity with (100/X) where X is the average utilization percentage (the examples below is calculated assuming 75 % utilization).

Figure 19 also include a formula for calculating the distance between the booster compressors.

The cost formulas given in Figure 19 are only valid provided the design pressure drop is approximately as per formula in Table 30. As the design pressure drop has been optimized with respect to cost, both lower and higher design pressure drops will tend to increase the cost. Lower design pressure will increase the pipe-diameter/pipe-cost while higher design pressure drop will increase the booster compressor expenses.

| | | Capacity - Energy | | Capacity - Mass flow | | Pressures | |
|---|---|---|---|---|---|---|---|
| length, km | 500 | 4000 | MW HHV | 888,964 | TPY | Inlet filling compressor, bar | 35 |
| WACC, % | 5 | 126,144,000 | GJ/y | 2436 | TPD | Max grid, bar (note 3) | 140 |
| Power cost, €/MWh | 60 | 345,600 | GJ/day | 1128 | kNm3/h | Min grid, bar (note 4) | 40 |
| Utilization | 75 | **3383** | MW LHV | 1011 | MMSCF/d | | |

Note 1: = 170+60000* MW^(-0.7))/1000, [€/m/MW], MW=2500 MJ/s
Note 2: = 30* MW^(-0.3), [%/(MW*1000km)], MW=3250 MJ/s
Note 3: = discharge pressure for filling and boosting compressor
Note 4 = inlet pressure for boosting compressor

| | Item | Source | Lifetime y | Formular calc. orange cell | % loss MW*1000kr | %loss MW | MW | € MW*km | k€ MW | M€ | M€ y | € ton H2 | € GJ | Datasheet |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CAPEX | Pipe (material and installation) | Figure 2.4 | 50 | 170 + 50000 *MW^(-0.7), [€/km/MW] | | | | 320 | 160 | 641 | 35 | 53 | 0.371 | Not in datasheet |
| | Isolation & vent stations | Figure 2.4 | 50 | 0.4 + 3800 *MW^(-0.9), [€/km/MW] | | | | 2.6 | 1.3 | 5 | 0.3 | 0.4 | 0.003 | Not in datasheet |
| | Booster compressors | Figure 2.4 | 20 | 3+12000* MW^(-0.9), [€/km/MW] | | | | 9.9 | 4.9 | 20 | 1.6 | 2.4 | 0.017 | Not in datasheet |
| | => Total per length | Sum | | Sum | | | | **333** | **166** | **666** | **37** | **55** | **0.391** | 0.4 (note 1) |
| | Filling compresor | Figure 2.4 | 20 | 4+ 700* MW^(-0.6) , [€/MW] | | | | | 8.8 | 35 | 2.83 | 4.3 | 0.030 | Not in datasheet |
| | Metering station + scraper trap | Figure 2-4 | 50 | 5.2 [€] | | | | | | 5.2 | 0.3 | 0.4 | 0.003 | Not in datasheet |
| | => TOTAL | Sum | | Sum | | | | | | **706** | **40** | **60** | **0.424** | |
| OPEX | Filling compressor - power @ 100% cap. | Figure 2-4 | | 1.1 *( Pin^(1/3)-Pout^(1/3)), [%/MW] | | **2.1** | 63 | | | | 33 | 50 | 0.352 | 2.1 = 2.1 % in datasheet |
| | Booster compressors - power @100% cap. | Figure 2-4 | | 30* MW^(-0.3), [%/(MW*1000km)] | **2.5** | 1.2 | 37 | | | | 20 | 29 | 0.208 | 2.7 (note 2) |
| | Fixed O&M | | | | | | | | | | 1 | 1.5 | 0.011 | 0.5 €/km/y/MW |
| | => TOTAL | | | | | | | | | | **54** | **81** | **0.570** | |
| | TOTAL | | | | | | | | | | **94** | **141** | **0.99** | |

| | | Capacity - Energy | | Capacity - Mass flow | | Pressures | |
|---|---|---|---|---|---|---|---|
| length, km | 1000 | 13000 | MW HHV | 2,889,133 | TPY | Inlet filling compressor, bar | 35 |
| WACC, % | 5 | 409,968,000 | GJ/y | 7915 | TPD | Max grid, bar (note 3) | 140 |
| Power cost, €/MWh | 60 | 1,123,200 | GJ/day | 3667 | kNm3/h | Min grid, bar (note 4) | 40 |
| Utilization | 75 | **10994** | MW LHV | 3285 | MMSCF/d | | |

Note 1: = 170+60000* MW^(-0.7))/1000, [€/m/MW], MW=20000 MJ/s
Note 2: = 30* MW^(-0.3), [%/(MW*1000km)], MW=7500 MJ/s
Note 3: = discharge pressure for filling and boosting compressor
Note 4 = inlet pressure for boosting compressor

| | Item | Source | Lifetime y | Formular calc. orange cell | % loss MW*1000kr | %loss MW | MW | € MW*km | k€ MW | M€ | M€ y | € ton H2 | € GJ | Datasheet |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CAPEX | Pipe (material and installation) | Figure 2.4 | 50 | 170 + 50000 *MW^(-0.7), [€/km/MW] | | | | 236 | 236 | 3067 | 168 | 78 | 0.546 | Not in datasheet |
| | Isolation & vent stations | Figure 2.4 | 50 | 0.4 + 3800 *MW^(-0.9), [€/km/MW] | | | | 1.2 | 1.2 | 15 | 0.8 | 0.4 | 0.003 | Not in datasheet |
| | Booster compressors | Figure 2.4 | 20 | 3+12000* MW^(-0.9), [€/km/MW] | | | | 5.4 | 5.4 | 70 | 5.6 | 2.6 | 0.018 | Not in datasheet |
| | => Total per length | Sum | | Sum | | | | **242** | **242** | **3152** | **174** | **81** | **0.567** | 0.2 (note 1) |
| | Filling compresor | Figure 2.4 | 20 | 4+ 700* MW^(-0.6) , [€/MW] | | | | | 6.4 | 83 | 6.66 | 3.1 | 0.022 | Not in datasheet |
| | Metering station + scraper trap | Figure 2-4 | 50 | 5.2 [€] | | | | | | 5.2 | 0.3 | 0.1 | 0.001 | Not in datasheet |
| | => TOTAL | Sum | | Sum | | | | | | **3240** | **181** | **84** | **0.590** | |
| OPEX | Filling compressor - power @ 100% cap. | Figure 2-4 | | 1.1 *( Pin^(1/3)-Pout^(1/3)), [%/MW] | | **2.1** | 206 | | | | 108 | 50 | 0.352 | 2.1 = 2.1 % in datasheet |
| | Booster compressors - power @100% cap. | Figure 2-4 | | 30* MW^(-0.3), [%/(MW*1000km)] | **1.7** | 1.7 | 171 | | | | 90 | 41 | 0.292 | 2.1 (note 2) |
| | Fixed O&M | | | | | | | | | | 7 | 3.0 | 0.021 | 0.5 €/km/y/MW |
| | => TOTAL | | | | | | | | | | **204** | **94** | **0.665** | |
| | TOTAL | | | | | | | | | | **386** | **178** | **1.25** | |

| | | Capacity - Energy | | Capacity - Mass flow | | Pressures | |
|---|---|---|---|---|---|---|---|
| length, km | 1000 | 30000 | MW HHV | 6,667,230 | TPY | Inlet filling compressor, bar | 35 |
| WACC, % | 5 | 946,080,000 | GJ/y | 18266 | TPD | Max grid, bar (note 3) | 140 |
| Power cost, €/MWh | 60 | 2,592,000 | GJ/day | 8463 | kNm3/h | Min grid, bar (note 4) | 40 |
| Utilization | 75 | **25370** | MW LHV | 7582 | MMSCF/d | | |

Note 1: = 170+60000* MW^(-0.7))/1000, [€/m/MW], MW=20000 MJ/s
Note 2: = 30* MW^(-0.3), [%/(MW*1000km)], MW=20000 MJ/s
Note 3: = discharge pressure for filling and boosting compressor
Note 4 = inlet pressure for boosting compressor

| | Item | Source | Lifetime y | Formular calc. orange cell | % loss MW*1000kr | %loss MW | MW | € MW*km | k€ MW | M€ | M€ y | € ton H2 | € GJ | Datasheet |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CAPEX | Pipe (material and installation) | Figure 2.4 | 50 | 170 + 50000 *MW^(-0.7), [€/km/MW] | | | | 207 | 207 | 6202 | 340 | 68 | 0.479 | Not in datasheet |
| | Isolation & vent stations | Figure 2.4 | 50 | 0.4 + 3800 *MW^(-0.9), [€/km/MW] | | | | 0.8 | 0.8 | 23 | 1.2 | 0.2 | 0.002 | Not in datasheet |
| | Booster compressors | Figure 2.4 | 20 | 3+12000* MW^(-0.9), [€/km/MW] | | | | 4.1 | 4.1 | 124 | 9.9 | 2.0 | 0.014 | Not in datasheet |
| | => Total per length | Sum | | Sum | | | | **212** | **212** | **6348** | **351** | **70** | **0.494** | 0.2 (note 1) |
| | Filling compresor | Figure 2.4 | 20 | 4+ 700* MW^(-0.6) , [€/MW] | | | | | 5.4 | 163 | 13.10 | 2.6 | 0.018 | Not in datasheet |
| | Metering station + scraper trap | Figure 2-4 | 50 | 5.2 [€] | | | | | | 5.2 | 0.3 | 0.1 | 0.000 | Not in datasheet |
| | => TOTAL | Sum | | Sum | | | | | | **6517** | **364** | **73** | **0.513** | |
| OPEX | Filling compressor - power @ 100% cap. | Figure 2-4 | | 1.1 *( Pin^(1/3)-Pout^(1/3)), [%/MW] | | **2.1** | 476 | | | | 250 | 50 | 0.352 | 2.1 = 2.1 % in datasheet |
| | Booster compressors - power @100% cap. | Figure 2-4 | | 30* MW^(-0.3), [%/(MW*1000km)] | **1.4** | 1.4 | 306 | | | | 161 | 32 | 0.227 | 1.5 (note 2) |
| | Fixed O&M | | | | | | | | | | 15 | 3.0 | 0.021 | 0.5 €/km/y/MW |
| | => TOTAL | | | | | | | | | | **426** | **85** | **0.600** | |
| | TOTAL | | | | | | | | | | **790** | **158** | **1.11** | |

**Table 32: Calculation example – $H_2$ pipe cost using *Fejl! Henvisningskilde ikke fundet.*a – P=140 bar and average utilization of 75% is used.**

In Table 32 and Table 33, detailed cost estimates for various hydrogen transmission pipe capacity and length are given.

The first table calculate the cost for a 500 km pipe transporting 4000 MW (based on HHV). The pressure operating range is 40-140 bar and the filling pressure is 35 bar. An average utilization/load percentage of 75% is applied.

In Figure 19 the blue curve is the sum of:

- The red curve (pipe cost)
- The purple curve (insulation and vent station cost) and
- The gray curve (booster compressor cost).

Colors in Table 32 and Table 33 follow the color code in Figure 19.

In Table 32 the sum of the first, second and third row (row with red, purple and gray numbers) adds to the fourth row (i.e. the row with the blue numbers).

The "0.4 €/m/MW" listed in the "datasheet" column (the first example) is the value taken from the "Investment costs" data in the data sheet. This value is based on the formula for the blue curve (sum of pipe cost, insulation and vent station cost and booster compressor cost):

$$Investment\ Cost\ \left(\frac{€}{meter * \ MW}\right) = 170 + 60{,}000 * \frac{MW^{(-0.7)}}{1000}$$

Where 2500 MW (HHV) is used for the interval 1000-4000 MW line.

The power used for booster compression in Figure 19 and in the examples above are included in the "Energy losses" in the data sheet. This cost item in the data sheet is based on the formula:

$$Energy\ losses\ (\frac{\%}{MW\ * 1000\ km}) = 30 * MW\hat{}(-0.3)$$

Where 3250 MW (HHV) is used for the interval 1500-5000 MW line. This results in (rounded to) 2.7% loss pr. MW pr. 1000 km for pipeline capacity in the given interval.

The total cost for the 4,000 MW 500 km pipeline is 131 €/ton transported $H_2$ (or 0.92 €/GJ transported $H_2$ – note the energy is based on HHV).

The same calculation is performed for 1,000 km pipe with both 13,000 and 30,000 MW capacity. All calculations performed in Table 32 are repeated in the following table with P=70 bar instead of 140 bar.

| | | Capacity - Energy | | Capacity - Mass flow | | Pressures | | Notes |
|---|---|---|---|---|---|---|---|---|
| length, km | 500 | 4000 | MW HHV | 888,964 | TPY | Inlet filling compressor, bar | 35 | Note 1: = 170+55500* MW^(-0.7))/1000, [€/m/MW], MW=2500 MJ/s |
| WACC, % | 5 | 126,144,000 | GJ/y | 2436 | TPD | Max grid, bar (note 3) | 70 | Note 2: = 60* MW^(-0.35), [%/(MW*1000km)], MW=3250 MJ/s |
| Power cost, €/MWh | 60 | 345,600 | GJ/day | 1128 | kNm3/h | Min grid, bar (note 4) | 40 | Note 3: = discharge pressure for filling and boosting compressor |
| Utilization | 75 | **3383** | MW LHV | 1011 | MMSCF/d | | | Note 4 = inlet pressure for boosting compressor |

| | Item | Source | Lifetime y | Formular (calc. orange cell) | % loss MW*1000km | %loss MW | MW | € MW*km | k€ MW | M€ | M€ y | € ton H2 | € GJ | Datasheet |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CAPEX | Pipe (material and installation) | Figure 2.4 | 50 | 170 + 40000 *MW^(-0.7), [€/km/MW] | | | | 290 | 145 | 581 | 32 | 48 | 0.336 | Not in datasheet |
| | Isolation & vent stations | Figure 2.4 | 50 | 0.6 + 3900 *MW^(-0.9), [€/km/MW] | | | | 2.8 | 1.4 | 6 | 0.31 | 0.5 | 0.003 | Not in datasheet |
| | Booster compressors | Figure 2.4 | 20 | 15+34000* MW^(-0.9), [€/km/MW] | | | | 34.5 | 17.2 | 69 | 5.5 | 8.3 | 0.058 | Not in datasheet |
| | => Total per length | Sum | | Sum | | | | **328** | **164** | **655** | **38** | **56** | **0.398** | 0.4 (note 1) |
| | Filling compresor | Figure 2.4 | 20 | 7+ 600* MW^(-0.6) , [€/MW] | | | | | 11.1 | 45 | 3.58 | 5.4 | 0.038 | Not in datasheet |
| | Metering station + scraper trap | Figure 2-4 | 50 | 5.2 [€] | | | | | | 5.2 | 0.3 | 0.4 | 0.003 | Not in datasheet |
| | => TOTAL | Sum | | Sum | | | | | | **705** | **42** | **62** | **0.439** | |
| OPEX | Filling compressor - power @ 100% cap. | Figure 2-4 | | 1.1 *( Pin^(1/3)-Pout^(1/3)), [%/MW] | | **0.9** | 28 | | | | 15 | 22 | 0.156 | 0.9 = 2.1 % in datasheet |
| | Booster compressors - power @100% cap. | Figure 2-4 | | 60* MW^(-0.35), [%/(MW*1000km)] | 3.3 | 1.6 | 49 | | | | 26 | 39 | 0.274 | 3.5 (note 2) |
| | Fixed O&M | | | | | | | | | | 1 | 1.5 | 0.011 | 0.5 €/km/y/MW |
| | => TOTAL | | | | | | | | | | **42** | **63** | **0.441** | |
| | TOTAL | | | | | | | | | | **83** | **125** | **0.88** | |

| | | Capacity - Energy | | Capacity - Mass flow | | Pressures | | Notes |
|---|---|---|---|---|---|---|---|---|
| length, km | 1000 | 13000 | MW HHV | 2,889,133 | TPY | Inlet filling compressor, bar | 35 | Note 1: = 170+55500* MW^(-0.7))/1000, [€/m/MW], MW=20000 MJ/s |
| WACC, % | 5 | 409,968,000 | GJ/y | 7915 | TPD | Max grid, bar (note 3) | 70 | Note 2: = 60* MW^(-0.35), [%/(MW*1000km)], MW=7500 MJ/s |
| Power cost, €/MWh | 60 | 1,123,200 | GJ/day | 3667 | kNm3/h | Min grid, bar (note 4) | 40 | Note 3: = discharge pressure for filling and boosting compressor |
| Utilization | 75 | **10994** | MW LHV | 3285 | MMSCF/d | | | Note 4 = inlet pressure for boosting compressor |

| | Item | Source | Lifetime y | Formular (calc. orange cell) | % loss MW*1000km | %loss MW | MW | € MW*km | k€ MW | M€ | M€ y | € ton H2 | € GJ | Datasheet |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CAPEX | Pipe (material and installation) | Figure 2.4 | 50 | 170 + 40000 *MW^(-0.7), [€/km/MW] | | | | 223 | 223 | 2896 | 159 | 73 | 0.516 | Not in datasheet |
| | Isolation & vent stations | Figure 2.4 | 50 | 0.6 + 3900 *MW^(-0.9), [€/km/MW] | | | | 1.4 | 1.4 | 18 | 1.0 | 0.5 | 0.003 | Not in datasheet |
| | Booster compressors | Figure 2.4 | 20 | 15+34000* MW^(-0.9), [€/km/MW] | | | | 21.7 | 21.7 | 283 | 22.7 | 10.5 | 0.074 | Not in datasheet |
| | => Total per length | Sum | | Sum | | | | **246** | **246** | **3196** | **182** | **84** | **0.593** | 0.2 (note 1) |
| | Filling compresor | Figure 2.4 | 20 | 7+ 600* MW^(-0.6) , [€/MW] | | | | | 9.0 | 118 | 9.43 | 4.4 | 0.031 | Not in datasheet |
| | Metering station + scraper trap | Figure 2-4 | 50 | 5.2 [€] | | | | | | 5.2 | 0.3 | 0.1 | 0.001 | Not in datasheet |
| | => TOTAL | Sum | | Sum | | | | | | **3319** | **192** | **89** | **0.624** | |
| OPEX | Filling compressor - power @ 100% cap. | Figure 2-4 | | 1.1 *( Pin^(1/3)-Pout^(1/3)), [%/MW] | | **0.9** | 91 | | | | 48 | 22 | 0.156 | 0.9 = 2.1 % in datasheet |
| | Booster compressors - power @100% cap. | Figure 2-4 | | 60* MW^(-0.35), [%/(MW*1000km)] | 2.2 | 2.2 | 212 | | | | 112 | 52 | 0.363 | 2.6 (note 2) |
| | Fixed O&M | | | | | | | | | | 7 | 3.0 | 0.021 | 0.5 €/km/y/MW |
| | => TOTAL | | | | | | | | | | **166** | **77** | **0.540** | |
| | TOTAL | | | | | | | | | | **358** | **165** | **1.16** | |

| | | Capacity - Energy | | Capacity - Mass flow | | Pressures | | Notes |
|---|---|---|---|---|---|---|---|---|
| length, km | 1000 | 300000 | MW HHV | 66,672,304 | TPY | Inlet filling compressor, bar | 35 | Note 1: = 170+55500* MW^(-0.7))/1000, [€/m/MW], MW=20000 MJ/s |
| WACC, % | 5 | 9,460,800,000 | GJ/y | 182664 | TPD | Max grid, bar (note 3) | 70 | Note 2: = 60* MW^(-0.35), [%/(MW*1000km)], MW=20000 MJ/s |
| Power cost, €/MWh | 60 | 25,920,000 | GJ/day | 84633 | kNm3/h | Min grid, bar (note 4) | 40 | Note 3: = discharge pressure for filling and boosting compressor |
| Utilization | 75 | **253700** | MW LHV | 75816 | MMSCF/d | | | Note 4 = inlet pressure for boosting compressor |

| | Item | Source | Lifetime y | Formular (calc. orange cell) | % loss MW*1000km | %loss MW | MW | € MW*km | k€ MW | M€ | M€ y | € ton H2 | € GJ | Datasheet |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CAPEX | Pipe (material and installation) | Figure 2.4 | 50 | 170 + 40000 *MW^(-0.7), [€/km/MW] | | | | 176 | 176 | 52759 | 2890 | 58 | 0.407 | Not in datasheet |
| | Isolation & vent stations | Figure 2.4 | 50 | 0.6 + 3900 *MW^(-0.9), [€/km/MW] | | | | 0.6 | 0.6 | 194 | 10.6 | 0.2 | 0.001 | Not in datasheet |
| | Booster compressors | Figure 2.4 | 20 | 15+34000* MW^(-0.9), [€/km/MW] | | | | 15.4 | 15.4 | 4620 | 371 | 7.4 | 0.052 | Not in datasheet |
| | => Total per length | Sum | | Sum | | | | **192** | **192** | **57572** | **3271** | **65** | **0.461** | 0.2 (note 1) |
| | Filling compresor | Figure 2.4 | 20 | 7+ 600* MW^(-0.6) , [€/MW] | | | | | 7.3 | 2193 | 176 | 3.5 | 0.025 | Not in datasheet |
| | Metering station + scraper trap | Figure 2-4 | 50 | 5.2 [€] | | | | | | 5.2 | 0.3 | 0.0 | 0.000 | Not in datasheet |
| | => TOTAL | Sum | | Sum | | | | | | **59771** | **3448** | **69** | **0.486** | |
| OPEX | Filling compressor - power @ 100% cap. | Figure 2-4 | | 1.1 *( Pin^(1/3)-Pout^(1/3)), [%/MW] | | **0.9** | 2,104 | | | | 1106 | 22 | 0.156 | 0.9 = 2.1 % in datasheet |
| | Booster compressors - power @100% cap. | Figure 2-4 | | 60* MW^(-0.35), [%/(MW*1000km)] | 0.7 | 0.7 | 1,634 | | | | 859 | 17 | 0.121 | 1.9 (note 2) |
| | Fixed O&M | | | | | | | | | | 150 | 3.0 | 0.021 | 0.5 €/km/y/MW |
| | => TOTAL | | | | | | | | | | **2115** | **42** | **0.298** | |
| | TOTAL | | | | | | | | | | **5563** | **111** | **0.78** | |

**Table 33: Calculation example – $H_2$ pipe cost using Figure 14 b – P=70 bar and average utilization of 75% is used.**

Within Table 34 cost vs pipe diameter and duty is listed for both 140 bar and 70 bar pipes. Surprisingly, at very large pipes the cost of P=70 bar pipe is less than for the pipe with P=140 bar. A major reason is that the optimal dP/dL formula (see Table 30) for the two cases were so similar that the optimal dP/dL for P=70 have been applied for both. Thus, high pressure is from a cost point beneficial at low capacities while at larger capacities the cost become very identical.

As seen in the tables (and Figure 19), it is the "pipe material & installation" and the compressor power-consumption as well as power consumption for filling that contributes to the major part of the cost. Electrolysis Units that operate at higher pressure can in the future eliminate a major part of the filling power consumption.

An additional advantage of the high pressure is the additionally storage capability. The amount of hydrogen gas that can be contained within a given volume of pipe is 1.9 times larger at 140 bar than at 70 bar. Thus, the extra pressure give a huge additionally storage/line packing capability.

100% utilization

| Pressure | DN | CAPEX P+I+B | HHV | | LHV | | Cost All |
|---|---|---|---|---|---|---|---|
| | | | low | high | low | high | |
| bar | inch | €/m | MW | MW | MW | MW | €/kg*1000km |
| 70 | 4 | 210 | | 65 | | 55 | 1.22 |
| | 6 | 265 | 65 | 165 | 55 | 140 | 0.70 |
| | 8 | 340 | 165 | 285 | 140 | 240 | 0.52 |
| | 10 | 420 | 285 | 465 | 240 | 395 | 0.41 |
| | 12 | 470 | 465 | 690 | 395 | 580 | 0.34 |
| | 16 | 615 | 690 | 1130 | 580 | 960 | 0.27 |
| | 20 | 855 | 1130 | 1865 | 960 | 1575 | 0.23 |
| | 24 | 1160 | 1865 | 2795 | 1575 | 2365 | 0.20 |
| | 30 | 1390 | 2795 | 4845 | 2365 | 4095 | 0.17 |
| | 36 | 1845 | 4845 | 7280 | 4095 | 6155 | 0.15 |
| | 48 | 3025 | 7280 | 13800 | 6155 | 11670 | 0.13 |
| 140 | 4 | 230 | | 70 | | 60 | 1.08 |
| | 6 | 325 | 70 | 180 | 60 | 150 | 0.64 |
| | 8 | 430 | 180 | 320 | 150 | 270 | 0.48 |
| | 10 | 540 | 320 | 540 | 270 | 455 | 0.38 |
| | 12 | 635 | 540 | 785 | 455 | 665 | 0.33 |
| | 16 | 800 | 785 | 1385 | 665 | 1170 | 0.27 |
| | 20 | 1165 | 1385 | 2275 | 1170 | 1925 | 0.23 |
| | 24 | 1595 | 2275 | 3420 | 1925 | 2890 | 0.21 |
| | 30 | 2220 | 3420 | 5740 | 2890 | 4855 | 0.18 |
| | 36 | 3050 | 5740 | 8670 | 4855 | 7330 | 0.17 |
| | 48 | 5060 | 8670 | 16440 | 7330 | 13905 | 0.15 |

P=Pipe, I=Isolation and vent station, B=booster compressors

**Table 34: Duty ranges vs nominal diameter (DN) and cost. The cost in the last column is based on the high flow (i.e. the high MW).**

Table 35 list cost evaluations from other studies. Applied WACC and assumed life time of investment is unfortunately often not cited. Where sufficient information is given, the calculations have been performed with the cost optimized formulas developed here (i.e. the formulas in Figure 19 have been applied). The values match fine with the Hychain and the European hydrogen backbone studies while the IEA and IES studies seems more conservative than the results using the values in this catalogue.

| Other benchmark studies of hydrogen transmission lines | Year | Description of the study | Parameters used within this study | | | | | | | Cost € / kg*1000km | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | LHV GW | L km | Pmax bar | Pmin bar | Pfill bar | Retofit % | Utiliz % | Other | This |
| European-hydrogen backbone | 2020 | 13 GW (LHV), 48", 100-600 km, 67-80 bar, P=67-80 bar, Pfill=30-40 bar, SP(boost)=190-330 MW/1000 km, 57 % utilization, 75% retofit of existing piping | 13 | 1000 | 78 | 40 | 35 | 75 | 57 | 0.09-0.17 | 0.11 |
| | | | | | | | | 0 | 100 | 0.16-0.23 | 0.13 |
| | | | | | | | | 0 | 57 | | 0.17 |
| Hychain - CAPEX low | 2020 | 1000 km, huge pipes, 50 years, 5% wacc, 100 % capacity use | 30 | 1000 | 78 | 40 | 35 | 0 | 100 | 0.10 | 0.12 |
| Hychain - CAPEX high | | | | | | | | | | 0.18 | |
| IEA | | | | | | | | | | 0.59 | |
| Hydrogen generation in Europe (EC) | | | | | | | | | | | |
| - Guidehouse | 2019 | 48" pipe including compressor cost. Assume: P=70 bar, 75% utilization | 12 | 1000 | 70 | 40 | 35 | 0 | 75 | 0.23 | 0.15 |
| - BNEF | 2019 | 34", 75% utilization, 50 km distance. Assume P=70 bar | 6 | 1000 | 70 | 40 | 35 | 0 | 75 | 0.48 | 0.17 |
| - IES | 2019 | 1500 km | | | | | | | | 0.57 | |
| Hydrogen europe (2*40 MW) | | 2500 km, 2 times 48 inch. 50 year, 5% wacc, capacity use 50%. 40 GW require 66" pipe at 140 bar. Else it will be very costly do to high dP Assume 140 bar and 66" | 40 | 1000 | 140 | 40 | 35 | 0 | 50 | 0.08 | 0.17 |
| | | | | | | | | | 100 | | 0.13 |

**Table 35: Studies found in literature. L=Length, Retofit is percent retrofit of NG net, and utilize is utilization percentage. The column study list the values given in the listed studies, while the white backgrounded cells list the values calculated with the cost-formulas listed within this document. For all calculation here: WACC=5% and 50 year lifetime on "pipe + isolation station + metering and scraber traps and 20 years on compressors.**

<u>Capital cost of liquid fuel pipes (L20 (LPG, $NH_3$, DME) and LHC)</u>:

The capital cost (CAPEX) of pipe transport of <u>liquid fuels</u> can be approximated by the following formula:

$$CM = 56 * MTPD^{-0.77}, \qquad [CM] = \left(\frac{€/m}{MTPD}\right)$$

$$CE = CM * \frac{24 * 3.6}{HHV_{liquid}}, \qquad [CE] = \left(\frac{€/m}{MW}\right), \qquad [HHV_{liquid}] = \frac{MJ}{kg}$$

This formula also gives a good approximation of liquefied $NH_3$, DME and LPG. Thus, the cost per mass unit is approximately the same. The major difference between the different liquids is the specific energy density (HHV) where especially ammonia and alcohol have a lower energy density and is therefore more costly to transfer per energy unit.

## Variable operational cost

The variable operation cost will mainly be given by the energy used to boost the pressure as a result of friction losses in the transmission pipe.

**Hydrogen ($H_2$)**: The booster and filling losses as function of capacity is plotted in Figure 19.

**Liquid fuels ($NH_3$, DME, Toluene)**: With a dP/dL(max) or 0.04 bar/km, the operation cost is negligible.

## Fixed operation cost

The fixed operation cost include maintenance, salaries/wages, etc. While the compressor maintenance cost depends on the capacity of the compressor the fixed O&M have for hydrogen pipes been given as €/km/MW. For liquid carring pipe, the maintenance cost depends very little on the actual capacity. I.e. a value based on €/km have been judged more appropriate for describing a large capacity range.

**Hydrogen ($H_2$)**: 4% of average CAPEX have been used for 2020. 2% is used for 2030 and 1.5% is used for 2050. The decrease is judged based on IoT-maintenance of compressor is under strong development. Additionally, for the first pipes, additionally surveillance for hydrogen embrittlement is suspected.

**Liquid ($NH_3$, DME, Toluene)**: 1% of average CAPEX is assumed. No major reduction in maintenance cost is foreseen.

## Uncertainty

As the major cost is pipe material and installation the uncertainty is minor as this is mature technology.

Higher uncertainty is added to the upper end as there is a considerable higher risk of unforeseen elements making it more expensive than less expensive.

Improvements on directional drilling as well as approvement of stronger materials can have a larger cost impact on the installation cost.

The uncertainty on specific safety requirements will add some uncertainty to the cost estimates. Especially approvals, expropriation, cost due to resistance (especially in larger cities) is very difficult to estimate.

## Quantitative description

See separate Excel file for Data sheet

## 132 Transport by road

This catalogue includes transport of $H_2$, $NH_3$, DME and LHC by truck. Typical operation conditions for the transport is given in Table 37.

### Brief technology description

The advantage of road transportation is the flexibility and ability to collect and deliver at almost any location as well as low CAPEX. Road truck is more suitable for relatively short distances and for smaller volumes.

#### Trucks and trailers

Different designs of trucks and trailers are available depending if they are intended for bulk transport (large quantities from point A to point B) or distribution transport (small quantities to many costumers e.g. tank stations).

**Figure 20: a) Tank, b) trailer, and c) tank trailer (semi-trailer)**

The maximum permissible weight of lorries in Denmark is given in Table 36.

| Weight per non-drive axle | Weight per drive axle | Truck 2 axles | Truck 3 axles | Truck 4 axles | Road train 4 axles | Road train 5 axles | Road train 6 axles | Road train 7 axles |
|---|---|---|---|---|---|---|---|---|
| 10 t | 11.5 t | 18 t | 24 t | 32 t | 38 t | 44 t | 50 t | 56 t |

**Table 36: Permissible maximum weight of lorries in Denmark[15] (in ton).**

[15] Bekendtgørelse om køretøjers største bredde, længde, højde, vægt og akseltryk, BEK nr 1497 af 01/12/2016

## Tank types

Table 37 gives an overview of different types of truck-tanks and their associated cost (both CAPEX and variable operation cost).

| Figure Below | Fluid | Tank types | T, °C | P, barg | Capacity (typical) | Further info | CAPEX Truck & trailer, M€ |
|---|---|---|---|---|---|---|---|
| A, B | LHC | Non pressured Liquid tank | Amb. | 0.2-3.5 | 20-35 $m^3$ 15-35 t | Single wall, Aluminum, CS | 0.46 (LHC) |
| C | | | | | | Double wall, poison or corrosive fluid, Corrosive: SS, lined with rubber or plastic | |
| D | LPG, DME, $NH_3$ | Compressed liquid tank | Amb. | 5-35 | 13-45 $m^3$ 7-30 t | Single wall, Carbon steel | 0.70 (LPG & $NH_3$ & DME) |
| E | | Refrigerated liquid tanks | -50-(-90) | 1.5-35 | Up to 50 $m^3$ (<31 t) | Double walled with vacuum between, Boil-off loss | |
| F | $H_2$, NG | Compressed gas tanks (CH2, CNG) | Amb. | 275-500 | Up to 50 $m^3$ (<13 t LNG) (<1.5 t LH2) | Multiple tubes, each with a PSV. See Figure 22 | 0.98 (CH2) |
| E | | Cryogenic tank (LH2, LNG) | Down to -253 ($H_2$) -165 (NG) | 6-350 | Up to 50 $m^3$ (<33 t LNG) (<3.5 t LH2) | Double walled with vacuum between, Boil-off loss | 0.61 (LH2) |

**Table 37: Different types of tankers for fuel transport ref. 22.**

Tank trailers can be divided into the following categories:

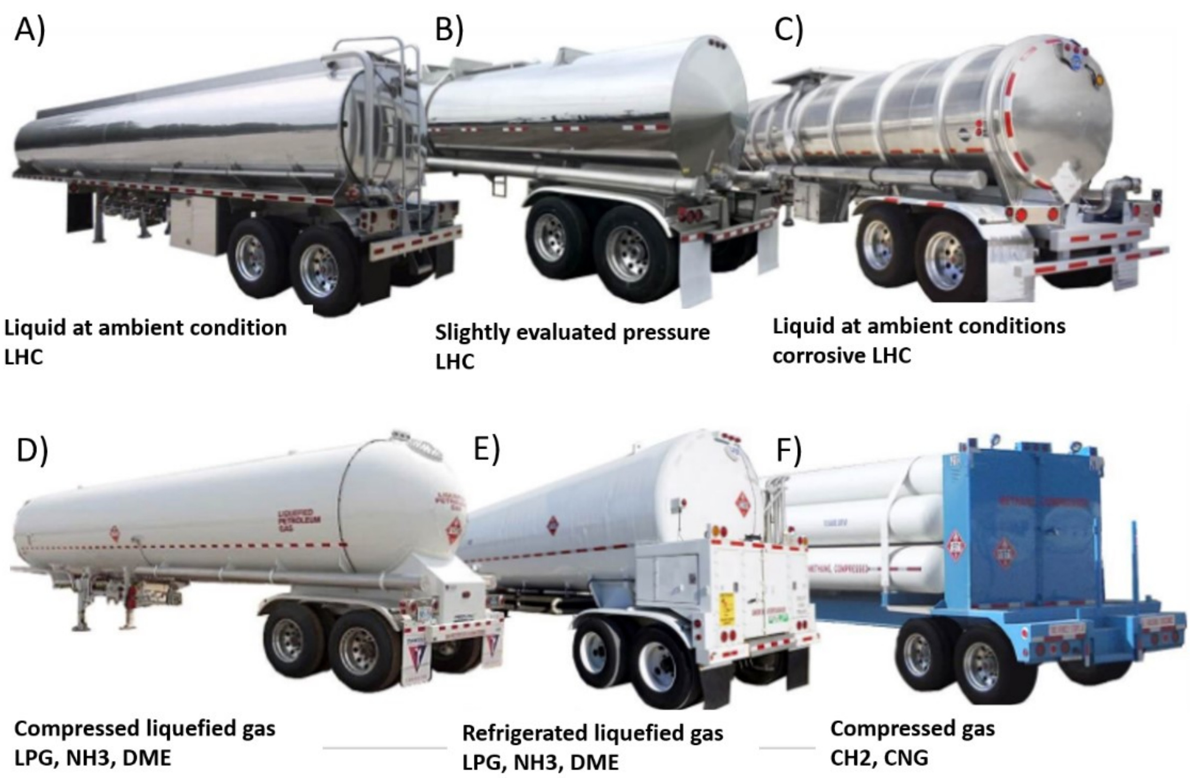



**Figure 21: Different tank trailer design [ref. 22].**

Hydrogen tanks can be categorized in type I-IV (see chapter about hydrogen storage in ref. 7). The type IV tanks seem to be more favorable for transportation due to the lower cylinder weight and no risk of corrosion.

Figure 22: Hydrogen tube trailer types

Tank design includes various safety functions (see figure below). Among these is division into several compartments to reduce the fluctuations/sloshing of the liquid in the tank. Additionally, a safety system that prevents overfilling of the tank is mandatory as well as it is important to inspect valves and tank for leaks before and after loading.

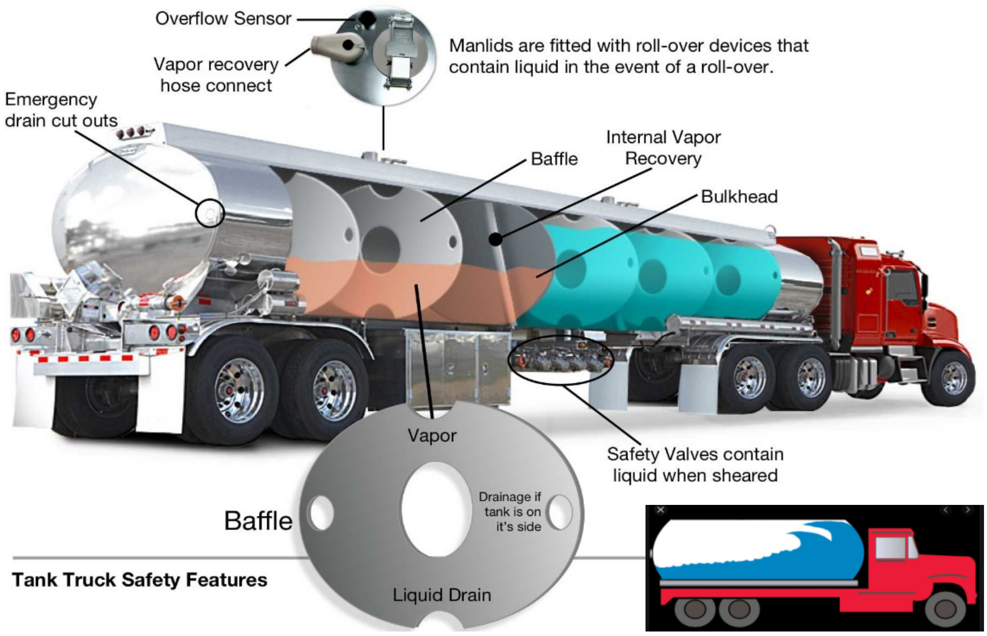



Figure 23: Tank safety features and internal baffles to prevent liquid splashing when driving.

## Input

Input is:

1. fuel to be transported
2. fuel for propulsion (see consumption in section *Energy losses*)
3. fuel for keeping transported fuel cold (only for L20, H2NG)

Point 3 is normally not used. Instead, some boil-off is accepted. This boil-off can be minimized by using the boil-off as fuel for propulsion.

Typically transport pressure and temperature is given in Table 13, Table 37 and Table 38.

Loading system:

Fuel to be transported is loaded into the truck via filling compressor/pump and some loading system (typically via a loading arm). Thus, a loading station normally compromise:

1. Storage tanks (see cost in section *Storage tanks*) and associated moat
2. Filling compressor/pump (see cost in *Conversion to/from carrier (LOHC)*, *Compressor* and *Pumps*)
3. Loading arms (cost is ~25-35 k€)
4. Fundament, piping, drip trays, various safety equipment

Figure 24: Loading arm

Loading system is not included in the datasheet as this cost depend strongly on location and how many that share the same loading equipment.

The time used for loading is included in the cost calculations.

## Output

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

Unloading system:

The unloading system normally compromise:

1. Storage tanks (see cost in *Storage tanks*)
2. Unloading via gravity (only possible for liquids) or via compressor/pumps (see cost in *Conversion to/from carrier (LOHC)*, *Compressor* and *Pumps*)
3. Fundament, piping, drip trays, various safety equipment

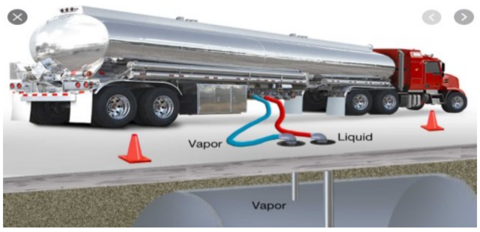


Figure 25: Unloading into storage tank via gravity

For liquid fuels, the fuel is normally unloaded via gravity (see Figure 20) or via a pump.

For compressed gas (CH2 and CNG), gravity cannot be used. To limit the compression loss, it is optimal if the trailer tubes is used as final storage vessels (see Figure 21).


Figure 26: Trailer and storage is same vessel.

For the same reason given for the loading system, the unloading system has not been included in the cost estimate in the datasheet.

## Efficiency and losses

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

## Application potential

Road truck transport of compressed gas ($H_2$ and NG) is generally only optimal for small volumes over limited distances.

For liquids, the volumetric energy density is much higher meaning much more energy can be transported per tour. Additionally, the filling and unloading system is much simpler and therefore inherit less losses. Thus, truck is generally optimal also for larger quantities.

## Typical capacities

Typical capacities of trucks are given in Table 38. Datasheets for the following have been included in this catalogue:

| Fluid | Net Truck | | P | T |
|---|---|---|---|---|
| | Mass, tons | Energy, GJ | bar | °C |
| CH2 | 1.5 | 180 | 350 - 500 | Ambient |
| LH2 | 3.1 | 383 | 6 - 350 | Down to -253 |
| $NH_3$ | 28 | 532 | 20 - 35 | Ambient |
| DME | 31 | 887 | | |
| Toluene | 44 | 1766 | 1.2 - 4.5 | Ambient |

**Table 38: Typical capacities and condition of tankers for liquid/gas transport**

## Environmental

As with all other trucks, environmental challenges are:

1. GHG and particle emissions
2. Noise pollution
3. Impact on landscape and habitats from infrastructure

## Research and development perspectives

Truck transportation is a well-proven mature technology (TRL=8-9).

Cost reduction improvements may include
1. Reduce the boil off – possible to improve the insulation
2. Improvement of the hydrogen trailer tubes: Lowering the weight of pressured tanks by developing stronger, lighter and cheaper composite materials will reduce transportation costs dramatically
3. Mass production of the hydrogen trailer tubes
4. Standardize the hydrogen trailer tubes so they are incorporated as storage vessels at the production and at the destination units

5. Reduce the loading/unloading time (for CH2, possible use the same vessels for storage and transportation)

## Prediction of performance and costs

An estimate for transportation by truck as function of capacity and distance has been derived:

Cost = VariableCost * Distance + FixedCost

The variable cost (VariableCost) include fuel consumption, driver wage and degradation due to usage (the latter is estimated by multiplying "CAPEX + O&M" with time fraction it is driving).

The fixed cost (FixedCost) include wage for supervision and the remaining "CAPEX + O&M".

In the calculation of a cost factors the following is assumed:

1. CAPEX of trailer truck used is given in Table 37
2. Annual Fixed O&M is set to 5% of CAPEX
3. Loading/unloading time used is given in Table 39
4. Availability is set to 8000 h per year
5. Driver cost is 45 EUR/h (operation 24/7).
6. Fuel consumption (MJ/km) used is listed in *Energy losses* and fuel cost is 29 EUR/kJ.
7. Average speed is 60 km/h.
8. Truck CAPEX is annualized with 5% interest over 6 years (assumed lifetime).

With the above assumptions the cost of $NH_3$ transport is modelled by:

$$Cost = 4.5 \frac{€}{t\ NH_3} + Distance \ \cdot 0.13 \frac{€}{t\ NH_3 \cdot km}$$

Example of cost of transport
Based on the above, cost for 30 and 100 km drive are estimated:

| Fluid | Loading/ unloading hours, 2020/2030/2050 | Reference | FixedCost €/t | Variable Cost €/(t*km) | Total 30 km €/t | Total 100 km €/t |
|---|---|---|---|---|---|---|
| LH2 | 5/4/3 | * | 37 | 1.1 | 71 | 149 |
| CH2 | 4.25/4/3 | ** | 132 | 2.6 | 211 | 396 |
| NH3 | 3/2.5/2 | *** | 4.5 | 0.13 | 8 | 17 |
| DME | /2.5/2/2 | **** | 3.7 | 0.12 | 7 | 16 |
| Toluene | /2.5/1.5/1.5 | **** | 2.1 | 0.08 | 5 | 10 |

Table 39: Typical values obtained from *Air liquid A/S, **Everfuel A/S, ***Give Svaergods A/S & ****Fjellerad Transport Aps (values for LPG and Diesel is used). Values are for 2020.

## Uncertainty

Transport of LHC are a mature technology, i.e. little uncertainty is assumed.

Transport of L20 (i.e. NH3, DME and LPG) is also mature, especially LPG. NH3 is very toxic and a little higher uncertainty to the high end have been added.

For LH2 and CH2 high uncertainty is added, especially to future values as major improvements are expected (see section *Research and development perspectives*) but unsure.

## Quantitative description

See separate Excel file for Data sheet

# 133 Transport by ship

## Brief technology description

|  |  |  |
|---|---|---|
| $NH_3$ | LNG | LH2 (future) |

### Ship and tank types

For ship transport, only liquid transport exist, most likely because they are not economically favourable due to low volumetric energy density and requirement to very high vessel vall thickness. Thus, only moderate pressure levels (<20 bar) exist, i.e. it is not possible to transport $H_2$ and NG as compressed gases. However, there exist development projects that look at marine transport of CNG [ref. 11] and marine transport of LH2 [ref. 25].

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

| Fluid | Tank types (fluid phase) | T, °C | P, barg | Tank Class | Capacity (typical), m3 | Ships today | CAPEX M€ |
|---|---|---|---|---|---|---|---|
| LHC | Oil tankers (LHC) | Amb. | Atm. | Integral | 3,000-120,000 | 800 | 31[16] (50,000 m$^3$) |
| LPG DME | Full refrigerated (refrigerated liquefied gas) | -48 | Atm. | A | 15,000-200,000 | Almost 300 | 79[18] (80,000 m$^3$) |
| $NH_3$[17] | Semi-refrigerated (refrigerated + comp. liquefied gas) | -10 | 4-17 | C | 6,000-12,000 | | |
| | Pressurized (compressed liquefied gas) | Amb | ≥17[19] | C | 1,000-3,000 | 300 | |
| LNG | Cryogenic cooling | -165 | Atm. | A, B, M | 40,000 – 135,000 | 500 | 155[20] (145,000 m$^3$) |
| LH2[21] | Cryogenic cooling | -253 | Atm. | ? | 1,250 | 1 (expected in end of 2020) | |

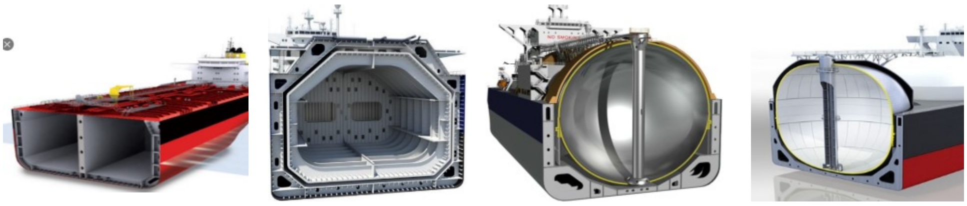
**Table 40: Different types of tankers for liquid/gas transport**

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

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

[16] BRS group annual review 2019
[17] Other fluids that can be transported via LPG tankers: Ethylene (full and semi refrigerated), Propane, Butane and Propylene.
[18] https://www.seatrade-maritime.com/tankers/euronav-buys-another-scrubber-fitted-resale-vlcc-newbuild
[19] Correspond to vapor pressure of LPG at ~45°C.
[20] Danish Ship Finance, Shipping market review 2019
[21] https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487

4. Membrane tanks (M)



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

**Figure 27: Different tank classes. The most cost-efficient onboard storage of ammonia seems to be class C (pressurized tanks) (Topsoe, 2020).**

Max size of ships are given by the following classes:

| Max size class | Max Length m | Max Beam m | Max Draft m | Max dead weight ton (DWT) | Application/info |
|---|---|---|---|---|---|
| Coastal Tanker | 205 m | 29 m | 16 m | 50,000 | mainly used for transportation of refined products |
| Aframax | 245 m | 34 m | 20 m | 80,000 | AFRA (Average Freight Rate Assessment |
| Suezmax | 285 m | 45 m | 23 m | 125,000-180,000 | Originally the max. capacity of the Suez Canal. |
| Very large crude carrier (VLCC) | 330 m | 55 m | 28 m | 320,000 | Oil tankers |
| Ultra large crude carrier (ULCC) | 415 m | 63 m | 35 m | 550,000 | Oil tankers |

**Table 41: Tanker size classes**

### Reliquification onboard

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

## Input

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

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

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

**Fuel used to drive the ship:**
Fuel consumption for propulsion is described in *Energy losses*.

## Output

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

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

## Efficiency and losses

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

## Application potential

Ships will be applicable for point to point transportation.

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

## Typical capacities

Typical capacities of ships are given in Table 42.

| Fluid | Net Ship | | Pd | Td |
|---|---|---|---|---|
| | Mass, tons | Energy, GW | barg | °C |
| LH2 | 10.000* | 345 | Ambient | -253 |
| $NH_3$ | 45.000 | 240 | Ambient | -48 |
| DME | 45.000 | 366 | Ambient | -48 |
| Toluene | 45.000 | 508 | Ambient | Ambient |

**Table 42: Typical capacities of tankers for liquid/gas transport. * No liquid $H_2$ carriers are developed, so the numbers are based on an LNG carrier.**

## Environmental

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

Maritime transport account to 2-3 % of the total global CO2 emission.

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

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

Additionally, MEOC have adopted GHG emission goals of 50% reduction by 2050 compared to 2008. Finally, several initiatives are under way for environmental classifications of ships.[22]

Other environmental challenges

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

## Research and development perspectives

Liquid carriers are a proven commercial technology except for LH2. For LH2 TRL=5 while for the other it is 9.

Reduce GHG emission: Completely carbon-free $NH_3$ fueling engines are under development and is expected to be ready in 2023-24. Today, it is prohibited to use toxic products, i.e. ammonia, as fuels for ships, thus, amendment to the International code for safety for ships is required.

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

Developing LH2 technology for transport of liquid hydrogen by ship.

## Prediction of performance and costs

### Investment cost (CAPEX)

Based on the cost examples given in Figure 23 the red approximation seems valid for L20 fuels (LPG, DME, NH3 (and CO2)).

$$CAPEX = 4000 - 0.05 * M_{cargo}$$

Where $M_{cargo}$ is the weight of the fuel transported. CAPEX for LHC is based value are listed in Table 40 (equal to the green point in Figure 23). For LH2, an obtained cost for LNG is used Table 40 as no LH2 ships are constructed yet. LH2 ship is expected to be slightly more expensive than LNG ships as more extreme cooling is needed, i.e. more insulation is expected to minimize heat interaction with surrounding. Alternatively, more boil off loss will exist.

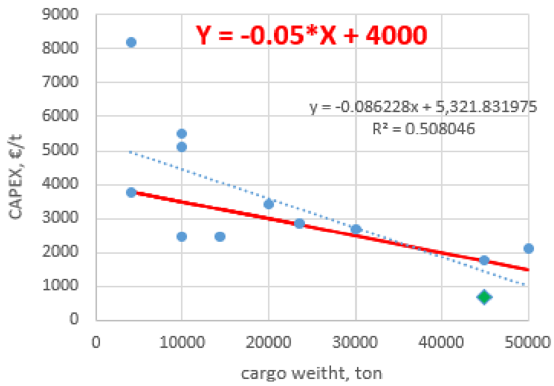



**Figure 28: CAPEX of L20 ships (including CO2 carrying ships) vs cargo weight from various obtained examples (green point is price for diesel tanker which is cheaper as no pressure or refrigerated vessels)**

[22] Environmental Classifications of Ships, Miljøstyrelsen 2014.

### Fixed O&M

Crew wages, maintenance, administration, tax and insurance, canal dues, tugs, pilotage (normal initial value is ~5% of CAPEX[23]).

### Port cost

Port cost have been estimated based on 2 days duration in port in both end and tariff for Port of Rotterdam (expensive end) have been applied.

### Energy demand

Fuel consumption is estimated using Equation 1 (see *Energy losses*). The following three cases are listed in the datasheet:

1. LHC: 50000 m3 MR2 tanker with a cargo fuel weight of ~45,000 t.
2. L20: 80000 m3 VLGC tanker with a cargo fuel weight of ~45,000 t.
3. LH2: 145000 m2 LNG tanker with a cargo LH2 fuel weight of ~10,000 t.

## Uncertainty

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

## Quantitative description

See separate Excel file for Data sheet

[23] Shipping CO2 – UK Cost Estimation Study, November 2018

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