

# Technology Data

## Energy transport



Energistyrelsen  
Danish Energy Agency

**ENERGINET**

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

### **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
<b>Nov 2020</b>	121-123	Addition of chapters on CO2 transport including Introduction to the topic

## Preface

The *Danish Energy Agency* and *Energinet*, the Danish transmission system operator, publish catalogues containing data on technologies for energy transport. This is the first edition of the catalogue. This catalogue includes data on 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 og Energinet 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 og 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 forsyningsikkerhed, 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

Introduction .....	7
111 Electricity distribution grid.....	31
112 Natural gas distribution grid .....	57
113 District heating distribution and transmission grid .....	76
Introduction to CO <sub>2</sub> transport.....	96
121 CO <sub>2</sub> transport in pipelines .....	110
122 CO <sub>2</sub> transport by ship.....	118
123 CO <sub>2</sub> transport by road .....	126

## 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

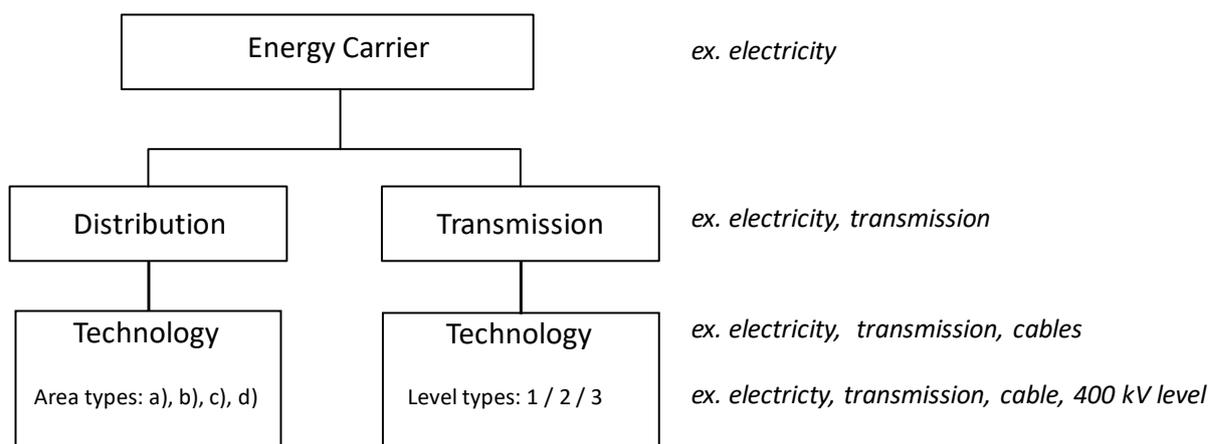
Other energy transport systems such as networks for hydrogen, biogas etc. as well as road and sea transport of liquid and solid fuels are not included. Energy storage installations in the respective systems are treated in a separate catalogue on energy storage. The catalogue does not contain prices for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

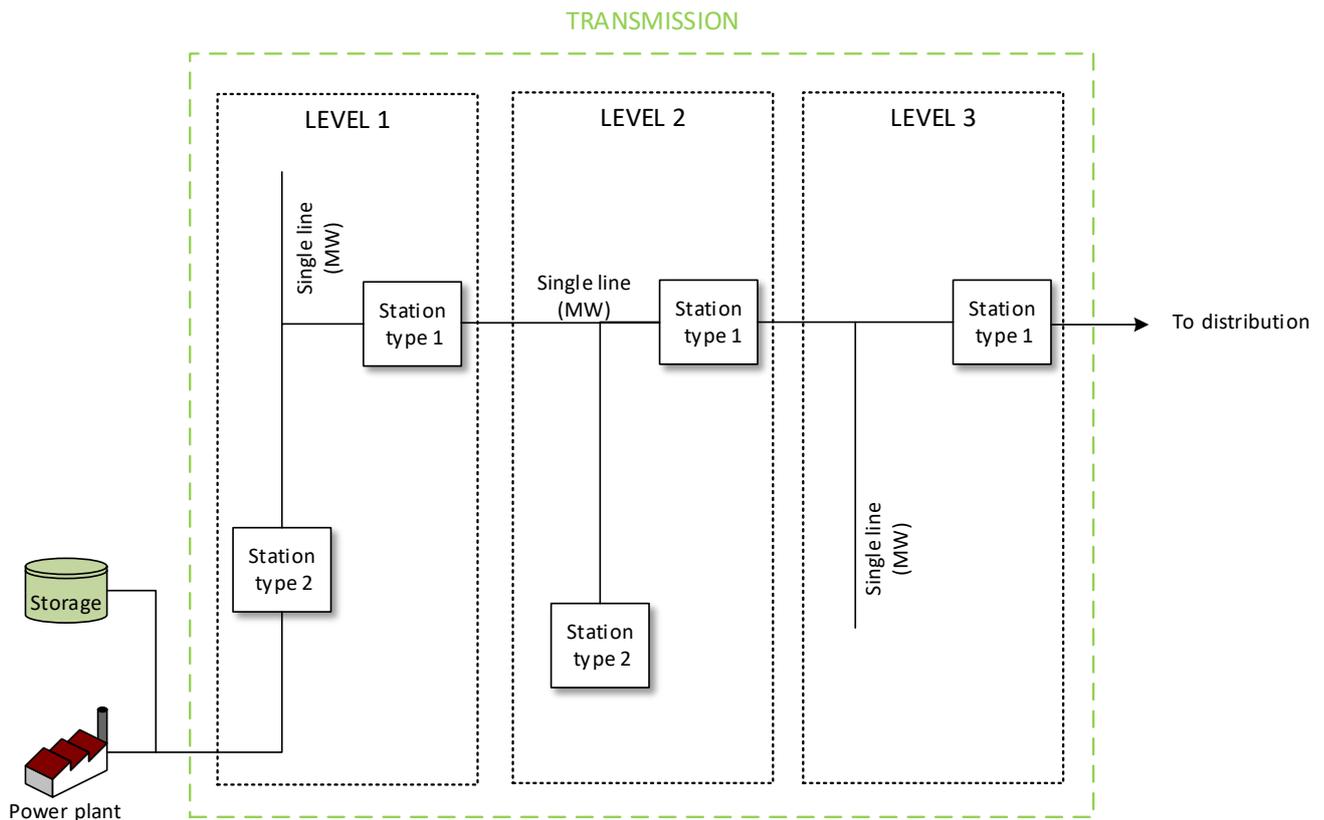
For each of the transmission technologies a number of levels are defined corresponding to the relevant voltage, pressure, or temperature levels. Separate data sheets are provided for each transmission level. For some technologies only one level is relevant.

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] (level change)	Stations [type 2] (auxiliary service)
Natural Gas	- M/R station (pressure release) - Compressor	
Electricity, overhead lines	Transformer station	- Capacitor banks - Reactors
Electricity, cables	Transformer station	- Capacitor banks - 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<sup>2</sup>). 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.

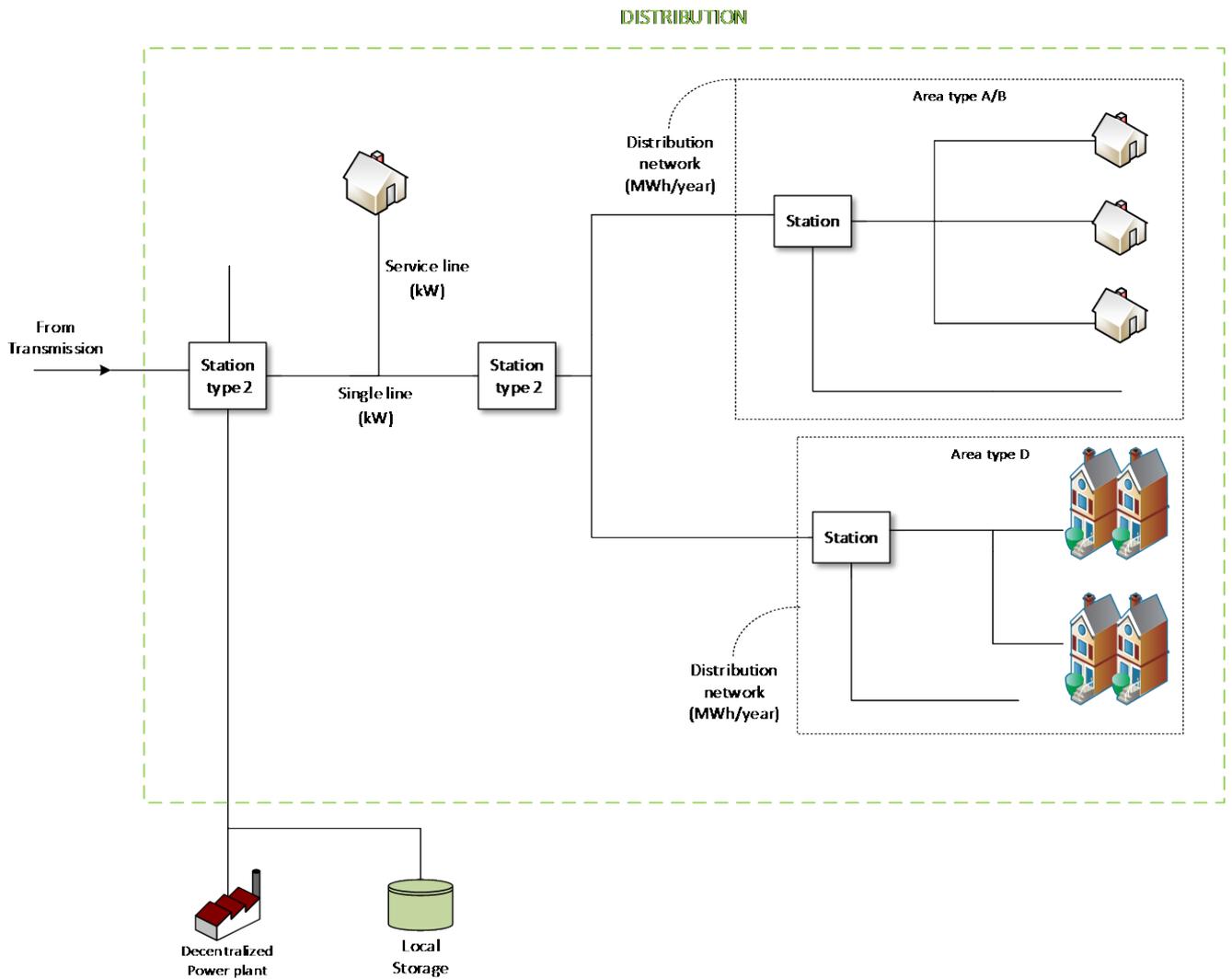
For a certain distribution technology, a number of different station types may be relevant:

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<sup>3</sup> or 0.011 MWh/Nm<sup>3</sup> 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
<ul style="list-style-type: none"> <li>• Natural gas, 80 bar</li> <li>• Natural gas, 40-16 bar</li>   <li>• Electricity, overhead lines, 400 kV</li> <li>• Electricity, overhead lines, 132/150 kV</li> <li>• Electricity, overhead lines, 50/60 kV</li> <li>• Electricity, cables, 400 kV</li> <li>• Electricity, cables, 132/150 kV</li> <li>• Electricity, cables, 50/60 kV</li> <li>• Electricity, HVDC, 400 kV</li> <li>• Electricity, HVDC sea cable, 250-400 kV</li> <li>• Electricity, HVAC sea cable, 400 kV</li> <li>• Electricity, HVAC sea cable, 132/150 kV</li> <li>• Electricity, HVAC sea cable, 50/60 kV</li>   <li>• District heating, &lt; 110 deg. C / 25 bar</li> <li>• District heating, &lt; 80 deg. C</li> </ul>	<ul style="list-style-type: none"> <li>• Natural gas, area type a)</li> <li>• Natural gas, area type b)</li> <li>• Natural gas, area type c)</li> <li>• Natural gas, area type d)</li>   <li>• Electricity, cables, area type a)</li> <li>• Electricity, cables, area type b)</li> <li>• Electricity, cables, area type c)</li> <li>• Electricity, cables, area type d)</li>   <li>• District heating, area type a)</li> <li>• District heating low temp., area type a)<sup>1</sup></li> <li>• District heating, area type b)</li> <li>• District heating, area type c)</li> <li>• District heating, area type d)</li> </ul>

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.

<sup>1</sup> 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 m<sup>2</sup> 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 2015 as well as the improvements assumed for the years 2020, 2030 and 2050.

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 2015*

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 2015 estimates.

If consistent data are not available, or if no suitable market standard has yet emerged for new technologies, the 2015 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 the period 2020 to 2050*

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 New Policies Scenario provides the framework for the Danish Energy Agency’s projection of international fuel prices and CO<sub>2</sub>-prices, and is also used in the preparation of this catalogue. Thus, the projections of the demand for technologies are defined in accordance with the thinking in the New Policies Scenario, described as follows:

*“New Policies Scenario: A scenario in the World Energy Outlook that takes account of broad policy commitments and plans that have been announced by countries, including national pledges to reduce greenhouse gas emissions and plans to phase out fossil energy subsidies, even if the measures to implement these commitments have yet to be identified or announced. This broadly serves as the IEA baseline scenario.” (ref. 7).*

Alternative projections may be presented as well relying for example on the IEA’s 450 Scenario (strong climate policies) or the IEA’s Current Policies Scenario (weaker climate policies).

- *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.

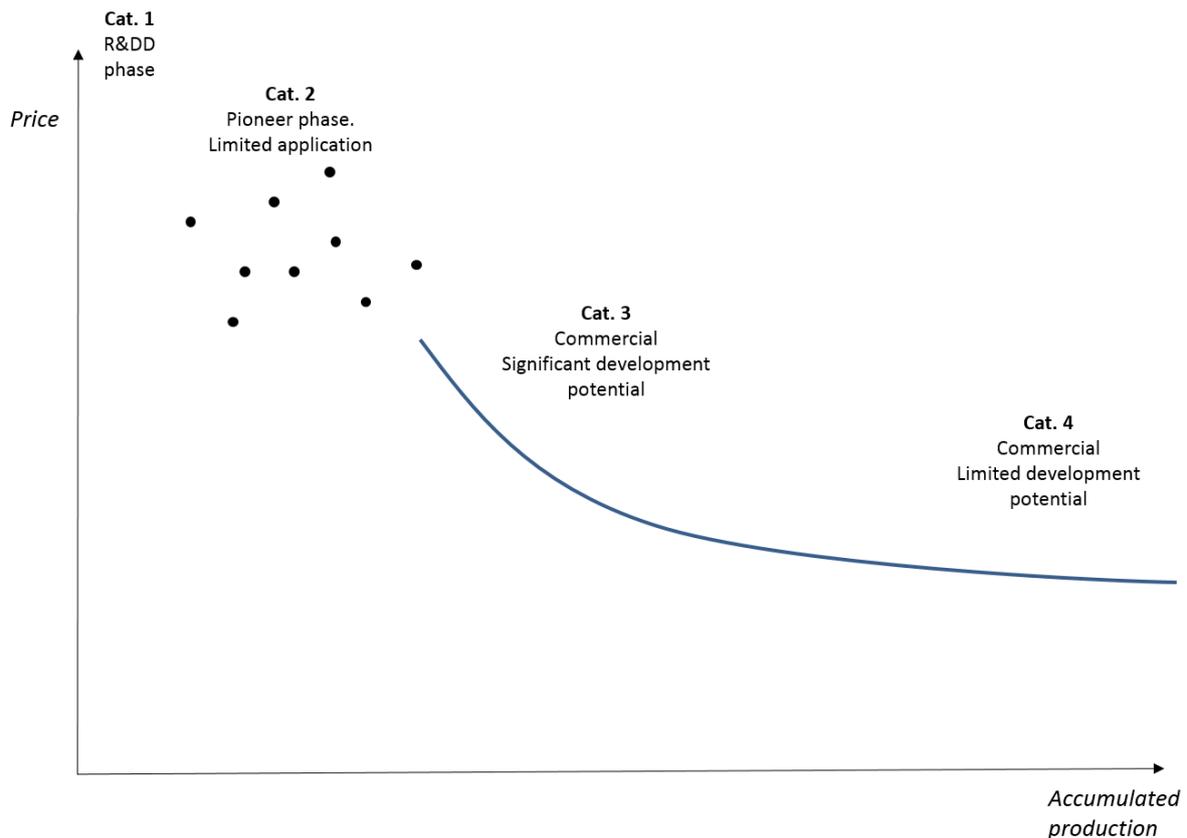
The potential for improving technologies is linked to the level of technological maturity. The technologies are categorized within one of the following four levels of technological maturity.

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. 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 fixed 2015 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, 2030 and 2050). 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.

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 years 2020 and 2050.

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 four time horizons (2015, 2020, 2030, and 2050)

/ (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	Energy Transport [Technology] Distribution, [area type sub-division]									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
<b>Energy/technical data</b>					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)										
<b>Financial data</b>										
<b>Investment costs</b>										
Distribution network costs (EUR/MWh/year) <b>[Area type]</b>									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)										

## Introduction

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)										
<b>[type 1]</b> station (EUR/MW)										
<b>[type 2]</b> station (EUR/MW)										
Investments, percentage installation (%)										
Investments, percentage materials (%)										
<b>Operation and maintenance costs</b>										
Fixed O&M (EUR/MW/year)										
Variable O&M (EUR/MWh)										
<b>Technology specific data</b>										

## Notes

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

**General Data Sheet – Transmission technologies**

*[one data sheet per level type, if relevant]*

Technology	Energy Transport [Technology] Transmission, [level type]									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		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)										

## Introduction

<b>Financial data</b>										
<b>Investment costs</b>										
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 (%)										
<b>Operation and maintenance costs</b>										
Fixed O&M (EUR/MW/km/year)										
Variable O&M (EUR/MWh/km)										
<b>Technology specific data</b>										

## Notes

### 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:

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

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 (€), fixed prices, at the 2015-level and exclude value added taxes (VAT) and other taxes. 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 2015 [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.

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 than 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.

### **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).

### 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, 2015.
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## 111 Electricity distribution grid

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### Amendments after publication date

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.

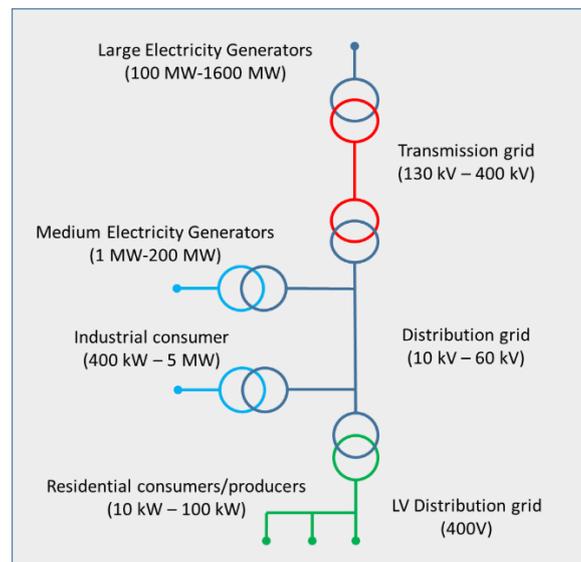


Figure 1: Major components in an electric power grid

### 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 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
<b>Energy/technical data</b>					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	
<b>Financial data</b>										
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<sup>2</sup> and 630 mm<sup>2</sup>, 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 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.
- 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<sup>2</sup>, 800mm<sup>2</sup> and 1000 mm<sup>2</sup>, 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<sup>2</sup>, 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

## References

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- 2 energinet.dk (<http://www.energinet.dk/DA/KLIMA-OG-MILJOE/Energinetdks-miljoepaavirkninger/Miljoepaavirkninger-ved-transport-af-el/Sider/Tab-i-elnettet.aspx>)
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- 4 International Electrotechnical Commission, Efficient Electrical Energy Transmission and Distribution (<http://www.iec.ch/about/brochures/pdf/technology/transmission.pdf>)
- 5 Svenska Kraftnät, Technology (<http://www.svk.se/en/grid-development/the-construction-process/technology/>)
- 6 EBR cost database, developed by Swedish bransch organisation Svensk Energi.
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- 8 Standard value list for the Swedish Energy Markets Inspectorate (2015 value) (<http://ei.se/sv/el/Elnat-och-natprisreglering/forhandsreglering-av-elnatstariffer-ar-2016-2019/dokument-elnatreglering/normvardeslista-elnat-2016-2019/>)
- 9 Swedish Energy Markets Inspectorate (<http://ei.se/sv/el/Elnat-och-natprisreglering/de-olika-delarna-i-intaktsramen/>)

**Table 2: Electricity distribution, Rural**

Technology	Electricity Distribution, Rural									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
<b>Energy/technical data</b>					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
<b>Financial data</b>										
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	H,F								
Investment costs; single line, 50-250 kW (EUR/m)	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	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									
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	M								

### Notes

- A The line losses were calculated using reference (1) and the formula  $\text{Total energy exported to customer} / \text{Total energy fed into the system}$ . 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 based 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 of 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

## References

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- 2 The Scope for Energy Saving in the EU through the Use of Energy-Efficient Electricity Distribution Transformers. H. De Keukebaer, D. Chapman, S. Fassbinder, M. McDermott, (2001).
- 3 International Electrotechnical Commission, Efficient Electrical Energy Transmission and Distribution (<http://www.iec.ch/about/brochures/pdf/technology/transmission.pdf>)
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- 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
<b>Energy/technical data</b>					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
<b>Financial data</b>										
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	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	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									
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	M								

## Notes

- A The line losses were calculated using reference (1) and the formula  $\text{Total energy exported to customer} / \text{Total energy fed into the system}$ . 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 based 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 of 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/>)
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- 3 International Electrotechnical Commission, Efficient Electrical Energy Transmission and Distribution (<http://www.iec.ch/about/brochures/pdf/technology/transmission.pdf>)
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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 4: Electricity distribution, city**

Technology	Energy Transport Electricity Distribution, City									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
<b>Energy/technical data</b>										
					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
<b>Financial data</b>										
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	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	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									
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	M								

### Notes

- A The line losses were calculated using reference (1) and the formula  $\text{Total energy exported to customer} / \text{Total energy fed into the system}$ . 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 based 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 of 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 assumed 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***

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- 2 The Scope for Energy Saving in the EU through the Use of Energy-Efficient Electricity Distribution Transformers. H. De Keukebaer, D. Chapman, S. Fassbinder, M. McDermott, (2001).
- 3 International Electrotechnical Commission, Efficient Electrical Energy Transmission and Distribution (<http://www.iec.ch/about/brochures/pdf/technology/transmission.pdf>)
- 4 Energimarknadsinspektionens föreskrifter om intäktsramar för elnätsföretag.  
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- 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
<b>Energy/technical data</b>					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
<b>Financial data</b>										
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	M									
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**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 of 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

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

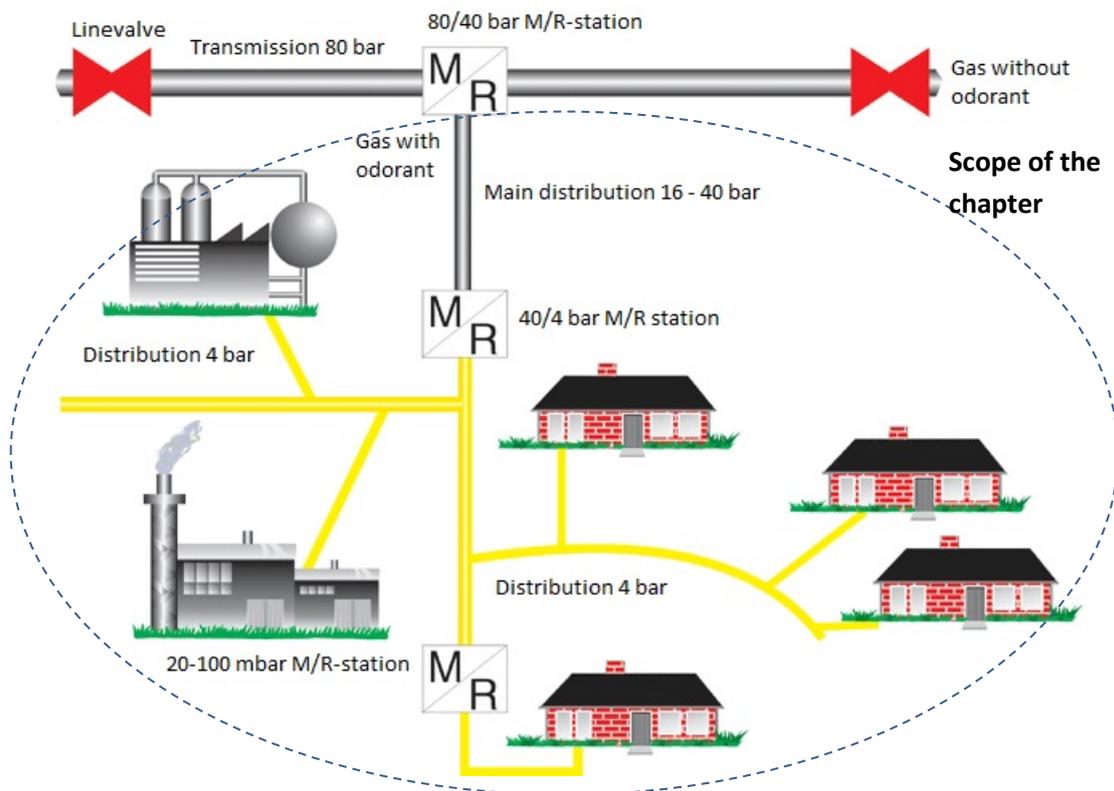


Figure 1 Overview of the gas network. Based on ref. [1].

### 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.

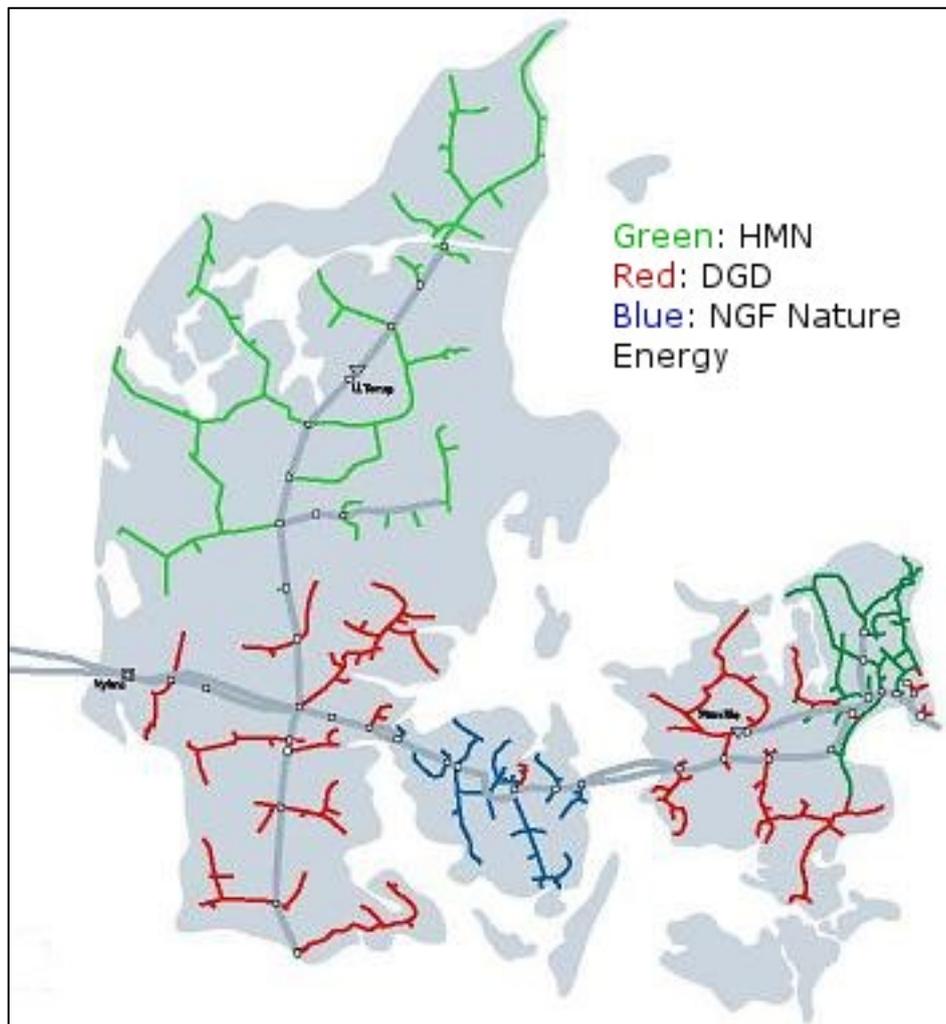
When the natural gas network was planned, the network was divided into five areas:

- 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<sup>2</sup>.

#### 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<sub>2</sub> 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 % CO<sub>2</sub>. In addition, biogas contains low concentrations of undesirable substances, e.g. impurities, such as H<sub>2</sub>S, 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 wobble limit, which is 50.8 MJ/Nm<sup>3</sup>. This equals a minimum methane content of 97.3 % assuming the rest is CO<sub>2</sub>.

H<sub>2</sub>S is limited to 5 mg/Nm<sup>3</sup>. 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](http://www.naturgasfakta.dk)
- [2] [www.gasmarked.dk](http://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
<b>Energy/technical data</b>					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
<b>Financial data</b>										
<b>Investment costs</b>										
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 m<sup>3</sup>/h is 20 % higher than a similar station with a capacity of 5.000 m<sup>3</sup>/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		
<b>Energy/technical data</b>					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
<b>Financial data</b>										
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
<b>Energy/technical data</b>					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
<b>Financial data</b>										
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
<b>Energy/technical data</b>	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
<b>Financial data</b>										
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
<b>Energy/technical data</b>					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
<b>Financial data</b>										
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
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## 113 District heating distribution and transmission grid

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### Qualitative description

#### Brief technology description

Hot water based district heating (DH) grids are used for transportation of centrally produced heat to consumers, residential as well as commercial. A variety of technologies can be used for heat production e.g. combined heat and power (CHP) plants, boilers, large-scale heat pumps, large electric boilers, excess heat and large-scale solar heating. Furthermore DH can integrate storage capacity which partially can decouple heat production from heat demand. District heating in Denmark is primarily used for space heating and domestic hot water. However, it can also be used for industrial purposes or production of cooling through absorption chillers. By centralizing the heat production it is possible to achieve a very efficient heat production e.g. by cogeneration of heat and electricity at CHP plants.

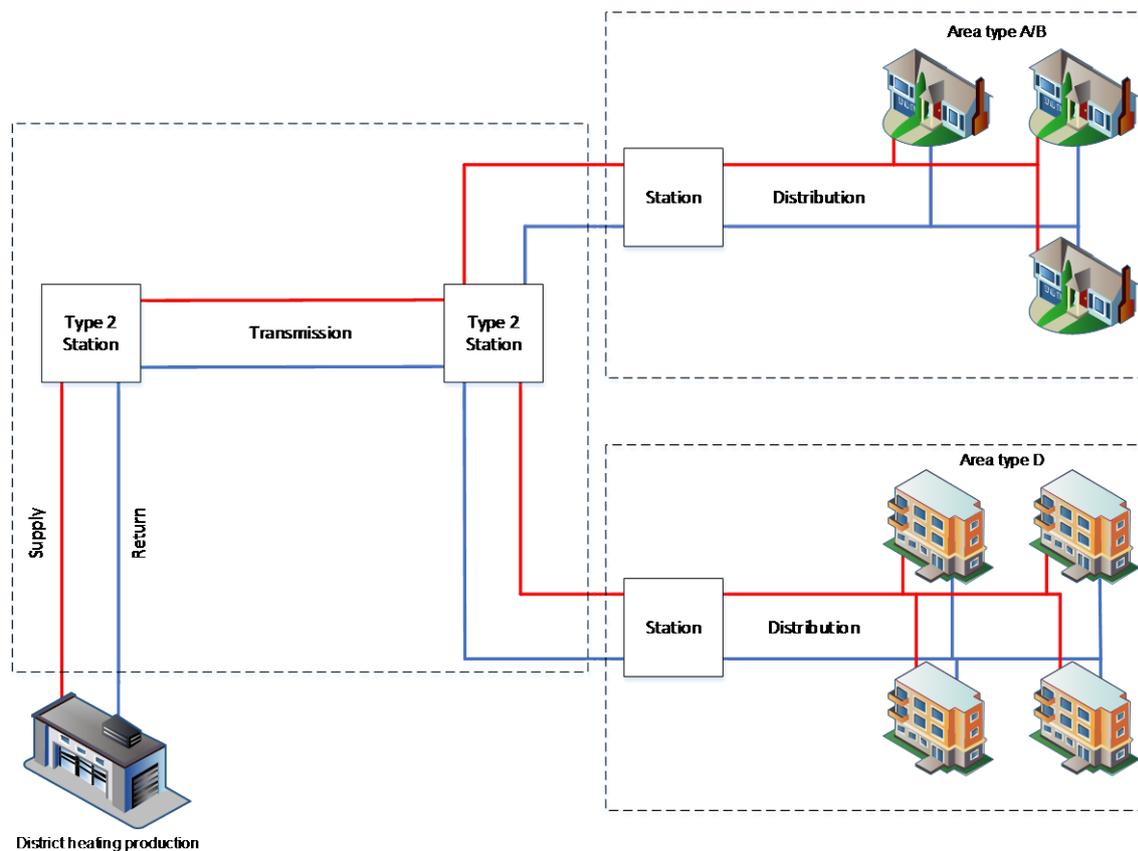


Figure 1 Illustration of district heating system

DH systems can vary in size from covering large areas like the Greater Copenhagen Area to small villages consisting of only a limited number of houses.

Large district heating systems may consist of both a transmission grid and a distribution grid. The distribution grid distributes the heat locally at a lower temperature/pressure while the transmission grid transports heat over long distances at higher temperature/pressure, typically from large heat producing units to distribution grids.

In the 1980's and 1990's a substantial development of DH took place in Denmark causing the very widespread use of district heating today. In large cities like Copenhagen and Aarhus, the central power plants are all CHP plants producing district heating in cogeneration with electricity. Until recently the fuels for these large central have mainly been coal and natural gas. However, in the recent years, several of the large central power plant units have been converted to biomass and more are planned to come.

District heating is also widely spread in a number of minor cities, towns and even villages around Denmark. In these areas district heating is mainly produced on small-scale CHP plants or heat only boilers. The fuels used are mainly natural gas and biomass. However, solar district heating has been growing rapidly over the last couple of years.

In the recent years, there has been a growing focus to develop the next generation of district heating also referred to as 4<sup>th</sup> generation district heating. The new generation of district heating is characterized by lower system temperatures along with a higher integration of renewable energy sources and a more intelligent interaction between different energy sources.

According to [1] approximately 64 % of the Danish households were supplied with district heating in 2015. In line with Danish and international energy and climate policies, district heating can play a big part in phasing out fossil fuels, making it possible that district heating will constitute an even larger percentage of the total heat supply in the future. However, this depends largely on district heating's competitiveness compared to individual heat solutions.

### Input

Input to a DH grid is heat from various sources, e.g. CHP plants, boilers, large-scale heat pumps, excess heat or large-scale solar heating etc.

### Output

The output is the same as the input, heat. However, due to grid losses the amount of heat delivered from the DH grid is lower than the amount delivered to it.

### Energy balance

Transportation of thermal energy in district heating pipes results in heat losses to the surroundings. The heat loss is in particular dependent on the length and temperature difference (between pipes and its surroundings) of the system and varies a lot from one system to another. Average grid losses are in the range of 15-20 % [2] [5]. In very large and dense systems, the loss can be as low as approximately 5 % while it can be more than 50 % in systems of very poor condition.

In heat exchanger efficiency is approx. 95 % of the delivered heat. Heat losses in pumping stations are negligible. Heat exchanger stations are normally only found in connection with transmission grids.

Most of the electricity for pumping is transformed to heat losses to the surroundings. A portion of this heat loss contributes to heating the district heating water.

### Description of transmission system

District heating transmission systems are used to transfer large quantities of thermal energy between different distribution areas using water as a media. Transmission systems operate at a higher temperature and pressure levels (<110 °C and 25 bar) compared to distribution systems.

Heat is delivered from transmission systems to distribution systems typically through heat exchanger stations in order to reduce the pressure and temperature levels.

Transmission systems often include pressure boosting pumping stations in order to prevent otherwise necessary upgrading of the grid's pressure level.

### Description of distribution system

A district heating distribution system distributes heat to consumers in a distribution area using water as a media. Distribution systems often operate with supply temperatures between 70-80 °C. However, due to an increasing attention to reducing temperature levels some areas operate at temperatures as low as 55-60 °C during the summer months [1]. Development for lowering the supply temperature even further is ongoing and decoupling of space heating and domestic hot water production is seen more and more often. This is 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 requires at least 50 °C to prevent the growth of legionella bacteria. By decoupling space heating and production of domestic hot water it is then possible to achieve several energy efficiency benefits in a district heating system.

Pressure levels are usually between 6.5 and 16 bars.

### Space requirement

Space requirement during construction for the trenching of district heating pipes varies depending on area conditions - paved or unpaved areas. Also, the permanent space requirement varies depending on whether twin pipes or single pipes are used. In unpaved areas, district heating pipes are laid in trenches with sloped walls requiring more surface area whereas vertical trench walls typically are used in paved areas [1] [2].

	Paved areas	Unpaved areas
Single Pipes	1-1.1	1.6-1.7
Twin Pipes	0.7-0.8	1.3-1.4

**Table 1** Space requirements, m<sup>2</sup> per MW per m (Based on a DN100 pipe assuming a  $\Delta T$  of 35 °C).

### Advantages/disadvantages

One of the big advantages of district heating systems is the high degree of flexibility it allows in terms of heat sources and operation of heat producing units. District heating allows numerous different production units in the same grid making it possible to prioritize the preferred heat production, e.g. the most efficient, economic, environmental friendly etc. This characteristic also makes district heating systems a secure solution for the future, since the current heat producing technologies can relatively easy be replaced when future better technologies become available.

District heating systems also allow for the utilization of geothermal heat, heat from waste incineration and surplus heat from industrial processes – heat sources than cannot be used for individual solutions.

If a district heating system is connected to a heat storage and heat is produced at CHP plants, large heat pumps or large electric boilers, the district heating system can offer flexibility services to the electricity grid 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.

The use of seasonal heat storage allows for the integration in the district heating system of large scale solar heating plants and hence takes advantage outside the summer season of the economically advantageous and CO<sub>2</sub>-neutral solar heat.

Finally, district heating 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.

The disadvantages of district heating systems are the high initial investment costs, heat losses in the system and the need for electricity to pump water through the pipes.

### **Environment**

Establishment of district heating grids have a minimal environmental impact during construction. The environmental conditions during operation are solely linked to the individual production technology and units.

### **Research and development perspectives**

Low temperature district heating (LTDH) has been a topic that has been investigated thoroughly for several years and through numerous projects technical concepts have been developed and demonstrated to a level where LTDH now is a commercial and reliable technology. LTDH is defined as having a supply temperature of 50-55 °C and a return temperature of 25-30 °C at the consumer.

During the last couple of years, concepts for ultra-low temperature district heating (ULTDH) have been developed, tested and demonstrated. ULTDH is a further development of low temperature district heating (LTDH) and has been defined as having a supply temperature below 45 °C and a return temperature of 20-25 °C at the consumer.

With ULTDH the link between district heating supply temperature and temperature requirement of domestic hot water (DHW) temperature is separated. DHW can be produced using a micro booster (small heat pump) or an electrical heater, and the risk of legionella bacteria can be avoided by the use of instant heat exchangers.

ULTDH is still a developing technology that has not yet been fully commercialized. However, full-scale demonstration project have shown that ULTDH is suitable for low-energy buildings as well as existing buildings if done correctly.

The advantages of LTDH and ULTDH are lower heat loss in the district heating system due to a lower temperature difference to the surroundings combined with increased fuel efficiency at the production plants.

Additionally lower district heating temperatures also make it possible to use a wider range of heat sources including surplus heat from industrial processes and renewable energy sources. Many renewable technologies also have better performance at lower temperatures meaning lower district heating temperatures can result in a better and more efficient integration of renewable energy sources.

The resulting energy savings could result in decreased fuel consumption. However, if it becomes necessary to boost the temperature at the consumer – using either a heat pump or electric heating – the extra energy consumption used in the boosting may offset the energy savings in the LTDH or ULTDH system.

LTDH and ULTDH grids are not considered to be more expensive to build than traditional district heating, they might even be slightly cheaper

LTDH and ULTDH are especially attractive in areas with a low heat density e.g. areas with new low-energy buildings.

#### Examples of market standard technology

Where possible, twin pipes should be used instead of single pipes as this ensures reduced heat losses as well as construction costs.

For smaller dimensions, (DN 15-DN 40) flexible pipes are preferable, whereas steel pipes will be necessary for larger dimensions. Twin pipes are not available in dimensions larger than DN 200.

Flexible pipes are often used as service lines, as the flexible material makes the installation easier. Service lines are often a plastic (PEX) pipe and can be supplied with an aluminum layer to ensure diffusion resistance. Service lines can also consist of flexible twin pipes with copper pipes and single lines with pipes of (cold-rolled) steel [4].

Both flexible and straight pipes are recommended with a diffusion barrier between the insulation and the polyethylene (PE) casing to ensure a low and unchanged thermal conductivity over time.



**Figure 1: An example of a flexible twin pipe and a steel twin pipe**

**District heating conversion in Birkerød** – Conversion from individual natural gas boilers to district heating in parts of Birkerød. More than 50 km of district heating pipes in sizes ranging up DN 300 connects consumers to district heating from I/S Norfors in Hørsholm. The system has a peak capacity of approximately 25 MW and delivers more than 70.000 MWh annually [5].

**Capacity upgrade in Aarhus** – Upgrade of the district heating capacity to the district Højbjerg in Aarhus. New 18 MW heat exchanger central and 1.6 km DN 250 transmission pipe. The heat exchanger central connects the transmission system to three separate distribution systems, each with its own operating pressure due to large height differences in the area [6].

**Prediction of performance and costs**

Prediction of cost is based on Sweco’s experience figures from district heating projects correlated with data from Svensk Fjärrvärmes Cost Catalog, which is a detailed database of costs covering labor and material cost based on actual construction costs [6].

District heating grids are a mature and commercial technology with large deployment. Pipe prices have had a very low variation and have more or less stabilized over the last couple of years. No significant changes in performance and costs are expected to happen to current technology in the foreseeable future. However, new technology, changes in production methods and changes in consumption patterns could possibly have an impact on performance and cost development.

Costs for labor, e.g. welding, excavation etc. are very dependent on geography and area type as considerable variations can be observed. Further, the general market conditions influence these costs.

**Uncertainty**

Performance data of district heating grids, such as energy losses, technical life-time and load profile typically depends on a number of project specific details and can be difficult to generalize.

Furthermore, if large changes were to happen on the basic design and operation of district heating grids it will have an impact on both performance and costs that are difficult to anticipate.

**References**

- [1] Årsberetning 2015, Dansk Fjernvarme, 2015  
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- [3] Stålrør, Isoplus, 2016  
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- [4] Technology Data for Energy Plants - Individual Heating Plants and Energy Transport, Danish Energy Agency, Oct. 2013

- [5] Følg fjernvarmeprojektet i Birkerød, Norfors, 2016  
<http://www.norfors.dk/da-DK/Fjernvarme/F%C3%B8lg-Fjernvarmeprojektet-i-Birker%C3%B8d.aspx>
- [6] Brøndum  
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- [8] Nøgletal 2016, Dansk Fjernvarme, 2016  
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## Data sheets

Table 11: District heating transmission

Technology	District Heating Transmission									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
<b>Energy/technical data</b>					Lower	Upper	Lower	Upper		
Energy losses, lines 1-20 MW (%)	3	3	3	3	1	5	1	5	A	1, 2
Energy losses, lines 20-100 MW (%)	1	1	1	1	0.5	2	0.5	2	A	1, 2
Energy losses, lines above 100 MW (%)	0.5	0.5	0.5	0.5	0.2	0.7	0.2	0.7	A	1, 2
Energy losses, Heat exchanger stations (%)	5	5	5	5	2	7	2	7		1
Energy losses, Pumping stations (%)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	G	1
Auxiliary electricity consumption (% energy transmitted)	2	2	2	2	0.5	5	0.5	5		1, 4
Technical life time (years)	40	40	40	40	30	50	30	50	B	1, 2
Typical load profile (-)	0.5	0.5	0.5	0.5	0.4	0.6	0.4	0.6		1
Construction time (years)	4	4	4	4	3	5	3	5		1
<b>Financial data</b>										
<b>Investment costs</b>										
Investment costs; single line, 0 - 50 MW (EUR/MW/m)	25	25	25	25	See Note	See Note	See Note	See Note	C, D	1, 3
Investment costs; single line, 50-100 MW (EUR/MW/m)	12	12	12	12	See Note	See Note	See Note	See Note	C, D	1, 3
Investment costs; single line, 100 - 250 MW (EUR/MW/m)	9	9	9	9	See Note	See Note	See Note	See Note	C, D	1, 3
Investment costs; single line, 250-500 MW (EUR/MW/m)	6	6	6	6	See Note	See Note	See Note	See Note	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		
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		
Reinforcement costs (EUR/MW)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	E	
Investment costs; [type 1] station (EUR/MW)	115.000	115.000	115.000	115.000	92.000	138.000	92.000	138.000		1
Investment costs; [type 2] station (EUR/MW)	105.000	105.000	105.000	105.000	84.000	126.000	84.000	126.000		1
Investments, percentage installation	60%	60%	60%	60%	50%	75%	50%	75%	C	1, 3
Investments, percentage materials	40%	40%	40%	40%	25%	50%	25%	50%	C	1, 3
Fixed O&M (EUR/MW/km/year)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Variable O&M (EUR/MW/h/km)	0.1	0.1	0.1	0.1	0.05	1.5	0.05	1.5		1, 4

### *Notes*

- A The loss is per km of transmission line
- B 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. temperature variation, soil conditions etc.
- C An unpaved area is assumed
- D Two district heating 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. The cost is per trench meter.
- E Depends on the scale of the transmission grid and supply strategy of reserve capacity. Therefore, it is not possible to generalize these costs.
- G Energy losses in pumping stations can be considered negligible

### *References*

- 1 Based on Sweco experience figures
- 2 LOGSTOR A/S
- 3 Consolidated with data from Svensk Fjärrvärme
- 4 Consolidated with data from Dansk Fjernvarmes Årsstatistik 2016

Table 12: District heating distribution, rural

Technology	District Heating Distribution, Rural									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
<b>Energy/technical data</b>					Lower	Upper	Lower	Upper		
Energy losses, lines (%)	15	15	15	15	10	20	10	20	A, B	1
Energy losses, <b>Heat exchanger stations</b> (%)	5	5	5	5	2	7	2	7	C	2
Auxiliary electricity consumption (% of energy delivered)	2	2	2	2	0,5	3	0,5	3		2
Technical life time (years)	40	40	40	40	30	50	30	50	D	1
Typical load profile (-)										
- Residential	0.2	0.2	0.2	0.2	0.15	0.25	0.15	0.25		
- Commercial	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Construction time (years)	1	1	1	1	0.5	1.5	0.5	1.5		
<b>Financial data</b>										
Distribution network costs (EUR/MWh/year), Rural	720	720	720	720	See Note	See Note	See Note	See Note	E, F	2, 3
Investment costs; service line, 0 - 20 kW (EUR/unit)	3.785	3.785	3.785	3.785	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, 20 - 50 kW (EUR/unit)	4.135	4.135	4.135	4.135	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, 50-100 kW (EUR/unit)	4.735	4.735	4.735	4.735	See Note	See Note	See Note	See Note	F, G	2, 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		
Investment costs; single line, 0-50 kW (EUR/m)	280	280	280	280	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 50-250 kW (EUR/m)	355	355	355	355	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 100-250 kW (EUR/m)	370	370	370	370	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 250 kW - 1 MW (EUR/m)	460	460	460	460	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 1 MW - 5 MW (EUR/m)	640	640	640	640	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 5 MW - 25 MW (EUR/m)	1.185	1.185	1.185	1.185	See Note	See Note	See Note	See Note	F, H	2, 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		
Reinforcement costs (EUR/MW)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
<b>Heat exchanger station</b> (EUR/MW)	100.000	100.000	100.000	100.000	80.000	120.000	80.000	120.000	I	2
<b>Pumping station</b> (EUR/MW)	90.000	90.000	90.000	90.000	72.000	108.000	72.000	108.000	I	2
Investments, percentage installation	85%	85%	85%	85%	80%	90%	80%	90%	F	2
Investments, percentage materials	15%	15%	15%	15%	10%	20%	10%	20%	F	2
Fixed O&M (EUR/MW/year)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Variable O&M (EUR/MWh)	1.5	1.5	1.5	1.5	1	2	1	2		2, 4
<b>Technology specific data</b>										

Heat exchanger station below 1 MW(EUR/MW)	265.000	265.000	265.000	265.000	212.000	318.000	212.000	318.000		2
Pumping station below 1 MW (EUR/MW)	240.000	240.000	240.000	240.000	192.000	288.000	192.000	288.000		2

### Notes

- A For entire distribution network
- B Use of single pipes would lead to a higher heat loss
- C For heat exchanger stations the heat loss is below 5 % and varies depending on the level of thermal insulation. For pump stations the heat loss is negligible.
- D 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. temperature variation, soil conditions etc.
- E The distribution network costs are based on the total cost for the area type case divided by the yearly heat demand. An unpaved area is assumed for all economic values
- F An paved area is assumed for the distribution network. For service lines 50 % unpaved and 50 % paved area is assumed.
- G Cost of service lines is based on an average service line length of 15 meters. Two service lines 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. Service lines above 100 kW are not relevant in the specific area type.
- H Two district heating 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. The cost is per trench meter. Power levels above 25 MW are not relevant in the specific area type.
- I The value stated is for stations above 1 MW. Investment costs per MW for stations below 1 MW are very different compared to stations above 1 MW as specified under Technology specific data.

### References

- 1 LOGSTOR A/S
- 2 Based on Sweco experience figures
- 3 Consolidated with data from Svensk Fjärrvärme
- 4 Consolidated with data from Dansk Fjernvarmes Årsstatistik 2016

Table 13: District heating distribution, suburban

Technology	District Heating Distribution, Suburban									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
<b>Energy/technical data</b>					Lower	Upper	Lower	Upper		
Energy losses, lines (%)	14	14	14	14	10	17	10	17	A, B	1
Energy losses, <b>Heat exchanger stations</b> (%)	5	5	5	5	2	7	2	7	C	2
Auxiliary electricity consumption (% of energy delivered)	2	2	2	2	0,5	3	0,5	3		2
Technical life time (years)	40	40	40	40	30	50	30	50	D	1
Typical load profile (-)										
- Residential	0.2	0.2	0.2	0.2	0.15	0.25	0.15	0.25		
- Commercial	N/A	N/A	N/A	N/A						
Construction time (years)	1	1	1	1	0.5	1.5	0.5	1.5		
<b>Financial data</b>										
Distribution network costs (EUR/MWh/year) Suburban	655	655	655	655	See Note	See Note	See Note	See Note	E, F	2, 3
Investment costs; service line, 0 - 20 kW (EUR/unit)	3.785	3.785	3.785	3.785	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, 20 - 50 kW (EUR/unit)	4.135	4.135	4.135	4.135	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, 50-100 kW (EUR/unit)	4.735	4.735	4.735	4.735	See Note	See Note	See Note	See Note	F, G	2, 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		
Investment costs; single line, 0-50 kW (EUR/m)	280	280	280	280	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 50-250 kW (EUR/m)	355	355	355	355	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 100-250 kW (EUR/m)	370	370	370	370	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 250 kW - 1 MW (EUR/m)	460	460	460	460	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 1 MW - 5 MW (EUR/m)	640	640	640	640	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 5 MW - 25 MW (EUR/m)	1.185	1.185	1.185	1.185	See Note	See Note	See Note	See Note	F, H	2, 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		
Reinforcement costs (EUR/MW)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
<b>Heat exchanger station</b> (EUR/MW)	100.000	100.000	100.000	100.000	80.000	120.000	80.000	120.000	I	2
<b>Pumping station</b> (EUR/MW)	90.000	90.000	90.000	90.000	72.000	108.000	72.000	108.000	I	2
Investments, percentage installation	85%	85%	85%	85%	80%	90%	80%	90%	F	2
Investments, percentage materials	15%	15%	15%	15%	10%	20%	10%	20%	F	2
Fixed O&M (EUR/MW/year)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Variable O&M (EUR/MWh)	1.5	1.5	1.5	1.5	1	2	1	2		2, 4
<b>Technology specific data</b>										

Heat exchanger station below 1 MW(EUR/MW)	265.000	265.000	265.000	265.000	212.000	318.000	212.000	318.000		2
Pumping station below 1 MW (EUR/MW)	240.000	240.000	240.000	240.000	192.000	288.000	192.000	288.000		2

### Notes

- A For entire distribution network
- B Use of single pipes would lead to a higher heat loss
- C For heat exchanger stations the heat loss is below 5 % and varies depending on the level of thermal insulation. For pump stations the heat loss is negligible.
- D 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. temperature variation, soil conditions etc.
- E The distribution network costs are based on the total cost for the area type case divided by the yearly heat demand. An unpaved area is assumed for all economic values
- F An paved area is assumed for the distribution network. For service lines 50 % unpaved and 50 % paved area is assumed.
- G Cost of service lines is based on an average service line length of 15 meters. Two service lines 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. Service lines above 100 kW are not relevant in the specific area type.
- H Two district heating 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. The cost is per trench meter. Power levels above 25 MW are not relevant in the specific area type.
- I The value stated is for stations above 1 MW. Investment costs per MW for stations below 1 MW are very different compared to stations above 1 MW as specified under Technology specific data.

### References

- 1 LOGSTOR A/S
- 2 Based on Sweco experience figures
- 3 Consolidated with data from Svensk Fjärrvärme
- 4 Consolidated with data from Dansk Fjernvarmes Årsstatistik 2016

Table 14: District heating distribution, city

Technology	District Heating Distribution, City									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
<b>Energy/technical data</b>					Lower	Upper	Lower	Upper		
Energy losses, lines (%)	5	5	5	5	3	8	3	8	A, B	1
Energy losses, <b>Heat exchanger</b> stations (%)	5	5	5	5	2	7	2	7	C	2
Auxiliary electricity consumption (% of energy delivered)	2	2	2	2	0,5	3	0,5	3		2
Technical life time (years)	40	40	40	40	30	50	30	50	D	1
Typical load profile (-)										
- Residential	0.2	0.2	0.2	0.2	0.15	0.25	0.15	0.25		
- Commercial	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Construction time (years)	1	1	1	1	0.5	1.5	0.5	1.5		
<b>Financial data</b>										
Distribution network costs (EUR/MWh/year) City	150	150	150	150	See Note	See Note	See Note	See Note	E, F	2, 3
Investment costs; service line, 0 - 20 kW (EUR/unit)	4.645	4.645	4.645	4.645	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, 20 - 50 kW (EUR/unit)	5.025	5.025	5.025	5.025	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, 50-100 kW (EUR/unit)	5.685	5.685	5.685	5.685	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, above 100 kW (EUR/unit)	6.195	6.195	6.195	6.195	See Note	See Note	See Note	See Note	F, G, H	2, 3
Investment costs; single line, 0-50 kW (EUR/m)	280	280	280	280	See Note	See Note	See Note	See Note	F, I	2, 3
Investment costs; single line, 50-250 kW (EUR/m)	355	355	355	355	See Note	See Note	See Note	See Note	F, I	2, 3
Investment costs; single line, 100-250 kW (EUR/m)	370	370	370	370	See Note	See Note	See Note	See Note	F, I	2, 3
Investment costs; single line, 250 kW - 1 MW (EUR/m)	460	460	460	460	See Note	See Note	See Note	See Note	F, I	2, 3
Investment costs; single line, 1 MW - 5 MW (EUR/m)	640	640	640	640	See Note	See Note	See Note	See Note	F, I	2, 3
Investment costs; single line, 5 MW - 25 MW (EUR/m)	1.185	1.185	1.185	1.185	See Note	See Note	See Note	See Note	F, I	2, 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		
Reinforcement costs (EUR/MW)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
<b>Heat exchanger</b> station (EUR/MW)	100.000	100.000	100.000	100.000	80.000	120.000	80.000	120.000	J	2
<b>Pumping</b> station (EUR/MW)	90.000	90.000	90.000	90.000	72.000	108.000	72.000	108.000	J	2
Investments, percentage installation	85%	85%	85%	85%	80%	90%	80%	90%	F	2
Investments, percentage materials	15%	15%	15%	15%	10%	20%	10%	20%	F	2
Fixed O&M (EUR/MW/year)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Variable O&M (EUR/MWh)	1.5	1.5	1.5	1.5	1	2	1	2		2, 4
<b>Technology specific data</b>										

Heat exchanger station below 1 MW(EUR/MW)	265.000	265.000	265.000	265.000	212.000	318.000	212.000	318.000		2
Pumping station below 1 MW (EUR/MW)	240.000	240.000	240.000	240.000	192.000	288.000	192.000	288.000		2

### Notes

- A For entire distribution network
- B Use of single pipes would lead to a higher heat loss
- C For heat exchanger stations the heat loss is below 5 % and varies depending on the level of thermal insulation. For pump stations the heat loss is negligible.
- D 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. temperature variation, soil conditions etc.
- E The distribution network costs are based on the total cost for the area type case divided by the yearly heat demand. An unpaved area is assumed for all economic values
- F An paved area is assumed for the distribution network as well as service lines
- G Cost of service lines is based on an average service line length of 15 meters. Two service lines 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 The value stated is for a DN40 twin pipe. This pipe size is able to deliver up to around 230 kW. If a higher capacity is needed the price will increase.
- I Two district heating 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. The cost is per trench meter. Power levels above 25 MW are not relevant in the specific area type.
- J The value stated is for stations above 1 MW. Investment costs per MW for stations below 1 MW are very different compared to stations above 1 MW as specified under Technology specific data.

### References

- 1 LOGSTOR A/S
- 2 Based on Sweco experience figures
- 3 Consolidated with data from Svensk Fjärrvärme
- 4 Consolidated with data from Dansk Fjernvarmes Årsstatistik 2016

Table 15: District heating distribution, new developed area

Technology	District Heating Distribution, New Area									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
<b>Energy/technical data</b>					Lower	Upper	Lower	Upper		
Energy losses, lines (%)	18	18	18	18	10	25	10	25	A, B	1
Energy losses, <b>Heat exchanger</b> stations (%)	5	5	5	5	2	7	2	7	C	2
Auxiliary electricity consumption (% of energy delivered)	2	2	2	2	0,5	3	0,5	3		2
Technical life time (years)	40	40	40	40	30	50	30	50	D	1
Typical load profile (-)										
- Residential	0.2	0.2	0.2	0.2	0.15	0.25	0.15	0.25		
- Commercial	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Construction time (years)	1	1	1	1	0.5	1.5	0.5	1.5		
<b>Financial data</b>										
Distribution network costs (EUR/MWh/year) New developed residential area	655	655	655	655	See Note	See Note	See Note	See Note	E, F	2, 3
Investment costs; service line, 0 - 20 kW (EUR/unit)	2.925	2.925	2.925	2.925	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, 20 - 50 kW (EUR/unit)	3.375	3.375	3.375	3.375	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, 50-100 kW (EUR/unit)	3.775	3.775	3.775	3.775	See Note	See Note	See Note	See Note	F, G	2, 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		
Investment costs; single line, 0-50 kW (EUR/m)	180	180	180	180	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 50-250 kW (EUR/m)	235	235	235	235	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 100-250 kW (EUR/m)	250	250	250	250	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 250 kW - 1 MW (EUR/m)	320	320	320	320	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 1 MW - 5 MW (EUR/m)	455	455	455	455	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 5 MW - 25 MW (EUR/m)	900	900	900	900	See Note	See Note	See Note	See Note	F, H	2, 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		
Reinforcement costs (EUR/MW)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
<b>Heat exchanger</b> station (EUR/MW)	100.000	100.000	100.000	100.000	80.000	120.000	80.000	120.000	I	2
<b>Pumping</b> station (EUR/MW)	90.000	90.000	90.000	90.000	72.000	108.000	72.000	108.000	I	2
Investments, percentage installation	75%	75%	75%	75%	65%	80%	65%	80%	F	2
Investments, percentage materials	25%	25%	25%	25%	20%	35%	20%	35%	F	2
Fixed O&M (EUR/MW/year)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Variable O&M (EUR/MWh)	1.5	1.5	1.5	1.5	1	2	1	2		2, 4
<b>Technology specific data</b>										

Heat exchanger station below 1 MW(EUR/MW)	265.000	265.000	265.000	265.000	212.000	318.000	212.000	318.000		2
Pumping station below 1 MW (EUR/MW)	240.000	240.000	240.000	240.000	192.000	288.000	192.000	288.000		2

### Notes

- A For entire distribution network
- B Use of single pipes would lead to a higher heat loss
- C For heat exchanger stations the heat loss is below 5 % and varies depending on the level of thermal insulation. For pump stations the heat loss is negligible.
- D 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. temperature variation, soil conditions etc.
- E The distribution network costs are based on the total cost for the area type case divided by the yearly heat demand. An unpaved area is assumed for all economic values
- F An unpaved area is assumed
- G Cost of service lines is based on an average service line length of 15 meters. Two service lines 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. Service lines above 100 kW are not relevant in the specific area type.
- H Two district heating 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. The cost is per trench meter. Power levels above 25 MW are not relevant in the specific area type.
- I The value stated is for stations above 1 MW. Investment costs per MW for stations below 1 MW are very different compared to stations above 1 MW as specified under Technology specific data.

### References

- 1 LOGSTOR A/S
- 2 Based on Sweco experience figures
- 3 Consolidated with data from Svensk Fjärrvärme
- 4 Consolidated with data from Dansk Fjernvarmes Årsstatistik 2016

Table 16: District heating distribution, new developed area with low temperature district heating

Technology	Low Temperature District Heating Distribution, New Area									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
<b>Energy/technical data</b>										
					Lower	Upper	Lower	Upper		
Energy losses, lines (%)	10	10	10	10	8	12	8	12	A, B	1
Energy losses, <b>Heat exchanger</b> stations (%)	5	5	5	5	2	7	2	7	C	2
Auxiliary electricity consumption (% of energy delivered)	2	2	2	2	0,5	3	0,5	3		2
Technical life time (years)	40	40	40	40	30	50	30	50	D	1
Typical load profile (-)										
- Residential	0.2	0.2	0.2	0.2	0.15	0.25	0.15	0.25		
- Commercial	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Construction time (years)	1	1	1	1	0.5	1.5	0.5	1.5		
<b>Financial data</b>										
Distribution network costs (EUR/MWh/year) – New area	680	680	680	680	See Note	See Note	See Note	See Note	E, F	2, 3
Investment costs; service line, 0 - 20 kW (EUR/unit)	3.200	3.200	3.200	3.200	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, 20 - 50 kW (EUR/unit)	3.375	3.375	3.375	3.375	See Note	See Note	See Note	See Note	F, G	2, 3
Investment costs; service line, 50-100 kW (EUR/unit)	3.850	3.850	3.850	3.850	See Note	See Note	See Note	See Note	F, G	2, 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		
Investment costs; single line, 0-50 kW (EUR/m)	180	180	180	180	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 50-250 kW (EUR/m)	235	235	235	235	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 100-250 kW (EUR/m)	250	250	250	250	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 250 kW - 1 MW (EUR/m)	370	370	370	370	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 1 MW - 5 MW (EUR/m)	540	540	540	540	See Note	See Note	See Note	See Note	F, H	2, 3
Investment costs; single line, 5 MW - 25 MW (EUR/m)	955	955	955	955	See Note	See Note	See Note	See Note	F, H	2, 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		
Reinforcement costs (EUR/MW)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
<b>Heat exchanger</b> station (EUR/MW)	100.000	100.000	100.000	100.000	80.000	120.000	80.000	120.000	I	2
<b>Pumping</b> station (EUR/MW)	90.000	90.000	90.000	90.000	72.000	108.000	72.000	108.000	I	2
Investments, percentage installation	75%	75%	75%	75%	65%	80%	65%	80%	F	2
Investments, percentage materials	25%	25%	25%	25%	20%	35%	20%	35%	F	2
Fixed O&M (EUR/MW/year)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Variable O&M (EUR/MWh)	1.5	1.5	1.5	1.5	1	2	1	2		2, 4

<b>Technology specific data</b>										
Heat exchanger station below 1 MW(EUR/MW)	265.000	265.000	265.000	265.000	212.000	318.000	212.000	318.000		2
Pumping station below 1 MW (EUR/MW)	240.000	240.000	240.000	240.000	192.000	288.000	192.000	288.000		2

### *Notes*

- A For entire distribution network
- B Use of single pipes would lead to a higher heat loss
- C For heat exchanger stations the heat loss is below 5 % and varies depending on the level of thermal insulation. For pump stations the heat loss is negligible.
- D 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. temperature variation, soil conditions etc.
- E The distribution network costs are based on the total cost for the area type case divided by the yearly heat demand. An unpaved area is assumed for all economic values
- F An unpaved area is assumed
- G Cost of service lines is based on an average service line length of 15 meters. Two service lines 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. Service lines above 100 kW are not relevant in the specific area type.
- H Two district heating 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. The cost is per trench meter. Power levels above 25 MW are not relevant in the specific area type.
- I The value stated is for stations above 1 MW. Investment costs per MW for stations below 1 MW are very different compared to stations above 1 MW as specified under Technology specific data.

### *References*

- 1 LOGSTOR A/S
- 2 Based on Sweco experience figures
- 3 Consolidated with data from Svensk Fjärrvärme
- 4 Consolidated with data from Dansk Fjernvarmes Årsstatistik 2016

## Introduction to CO<sub>2</sub> transport

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### Amendments after publication date

Date	Ref.	Description
-	-	-

## General

The realisation of a complete carbon capture storage (CCS) and/or utilisation (CCU) value chain will nearly always involve transportation and or interim storage of CO<sub>2</sub>. This because the CO<sub>2</sub> emission sources and suitable geological storage and/or CO<sub>2</sub> utilisation sites are likely to be geographically separated. Moreover, it may be anticipated that the CO<sub>2</sub> supply from CO<sub>2</sub> capture facilities and the use at CO<sub>2</sub> utilisation facilities may not always be balanced hence interim CO<sub>2</sub> storage capacity will be required. Likewise, CO<sub>2</sub> buffering capacity may be required when changing from one mode of transportation to another.

This chapter of the technology catalogue will describe the different technologies available for transportation of CO<sub>2</sub> i.e. the link between CO<sub>2</sub> capture and CO<sub>2</sub> storage/utilisation. The main transport technologies described are:

- Pipeline transport
- Ship transport
- Road transport

The carbon capture technology catalogue describes the capture of CO<sub>2</sub> from an emission source or ambient air including CO<sub>2</sub> compression and liquefaction technology which will condition CO<sub>2</sub> into a suitable state for transportation.

This chapter only describes the transportation of CO<sub>2</sub> from capture to storage/utilisation site. The technology required for geological storage of CO<sub>2</sub> e.g. CO<sub>2</sub> injection equipment, injection well, etc. or CO<sub>2</sub> utilisation is not covered.

## CO<sub>2</sub> properties in relation to transport

The physical properties and phase behaviour of CO<sub>2</sub> are important to consider when selecting the design conditions for CO<sub>2</sub> transportation.

To facilitate cost optimal transportation of CO<sub>2</sub>, conditions that enable high CO<sub>2</sub> density is required. High density is obtained by compressing CO<sub>2</sub> to a high-pressure gas/fluid or through liquefaction to liquid state. Solid CO<sub>2</sub> (dry ice) has also high density but solid CO<sub>2</sub> is impractical to handle and store, hence solid-state transportation is not normally considered a viable option.

Figure 1 shows a pressure-temperature phase diagram of pure CO<sub>2</sub>. The critical point for CO<sub>2</sub> is at 31°C and 74 bar(a), which represents the highest temperature and pressure where a liquid phase can be present. On the lower temperature end of the phase diagram is the triple point of CO<sub>2</sub> -56.6°C and 5.2 bar(a), which represents the lower temperature and pressure where a liquid phase can be present.

For transport of CO<sub>2</sub> in liquid state e.g. by tanker truck or ship, it thus follows that the temperature must be in the range of -56 to +31°C and the pressure 5.2 to 74 bar(a). In practice some operating margin to the phase change curve will be required, which will reduce the operating window.

For CO<sub>2</sub> pipeline transport it is normally not desirable to operate at conditions where phase change may occur (gas-liquid). Therefore, pipelines are often operated above the critical pressure of CO<sub>2</sub> (74 bar) to avoid two phase formation. Another important factor is to achieve high density.

Figure 2 shows a relationship between pressure and CO<sub>2</sub> density. It appears that a CO<sub>2</sub> pipeline operating above the critical pressure (dense phase) may achieve CO<sub>2</sub> transport densities around 800-1000 kg/m<sup>3</sup> at typical temperatures for buried pipelines in Denmark. This is more than an order of magnitude higher density compared to what is known from the natural gas transmission net, which implies that relatively small pipeline diameters will be required for transport of CO<sub>2</sub>.

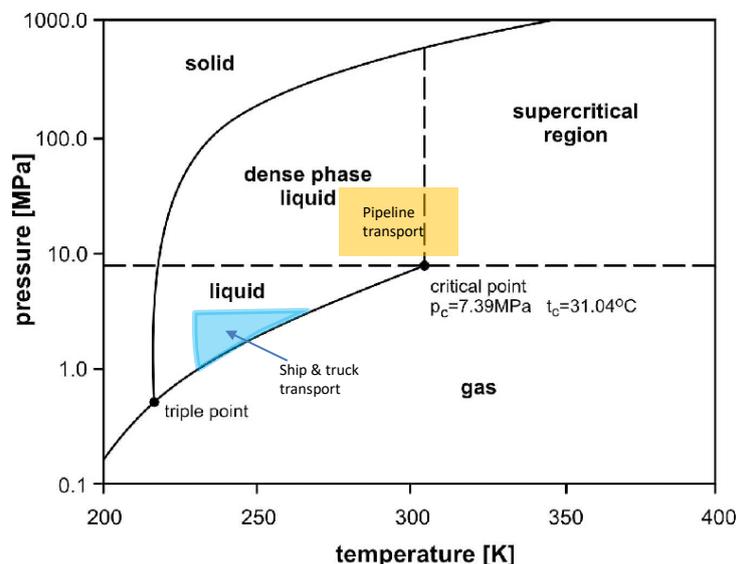
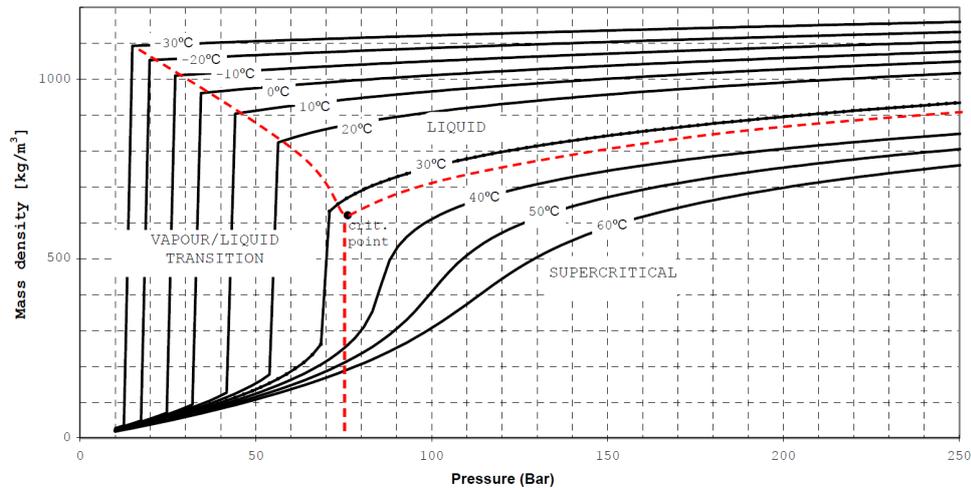


Figure 1. Pressure-temperature CO<sub>2</sub> phase diagram. Typical operating conditions for CO<sub>2</sub> pipeline as well as ship and truck transport indicated as coloured areas.



**Figure 2. Mass density of pure CO<sub>2</sub> as function of pressure based on Peng-Robinson EQS. Source: DNV-GL RP-J202.**

The above diagrams are representative for pure CO<sub>2</sub> only. The presence of other gases or contaminants (O<sub>2</sub>, N<sub>2</sub>, Ar, SO<sub>2</sub>, NO<sub>x</sub>, etc.) will alter the phase behaviour of CO<sub>2</sub> significantly. In general, the presence of contaminants tends to increase the critical pressure and temperature of CO<sub>2</sub>, hence higher pipeline pressures will be required to stay out of the two-phase region.

For liquefied CO<sub>2</sub> the presence of even trace amounts of non-condensable gases e.g. O<sub>2</sub>, Ar, N<sub>2</sub>, etc. will change the physical properties substantially as illustrated in Table 1.

**Table 1. Impact of non-condensable gases on vapour pressure of CO<sub>2</sub>. [1]**

Mixture	Vapour pressure at -50°C
CO <sub>2</sub> (100%)	6.7 bara
CO <sub>2</sub> mixture with 0.05 mol% N <sub>2</sub>	7.0 bara
CO <sub>2</sub> mixture with 0.1 mol% N <sub>2</sub>	7.3 bara
CO <sub>2</sub> mixture with 0.5 mol% N <sub>2</sub>	9.7 bara
CO <sub>2</sub> mixture with 0.05 mol% O <sub>2</sub>	6.9 bara
CO <sub>2</sub> mixture with 0.05 mol% H <sub>2</sub>	10.3 bara

Furthermore, with liquid CO<sub>2</sub> at low temperatures (cryogenic), the presence of even 100 ppm of water may lead to CO<sub>2</sub> hydrate or ice formation. This can cause severe operational problems such as plugging of valves, heat exchangers, etc. To circumvent such operational issues, CO<sub>2</sub> will be dehydrated to very low water content (<30 ppm) prior to liquefaction. Another issue with moisture is that CO<sub>2</sub> will be very corrosive for carbon steel in the presence of small amounts of H<sub>2</sub>O due to the formation of carbonic acid. This is why CO<sub>2</sub> is also dehydrated to low value (low dew point) prior to pipeline transport.

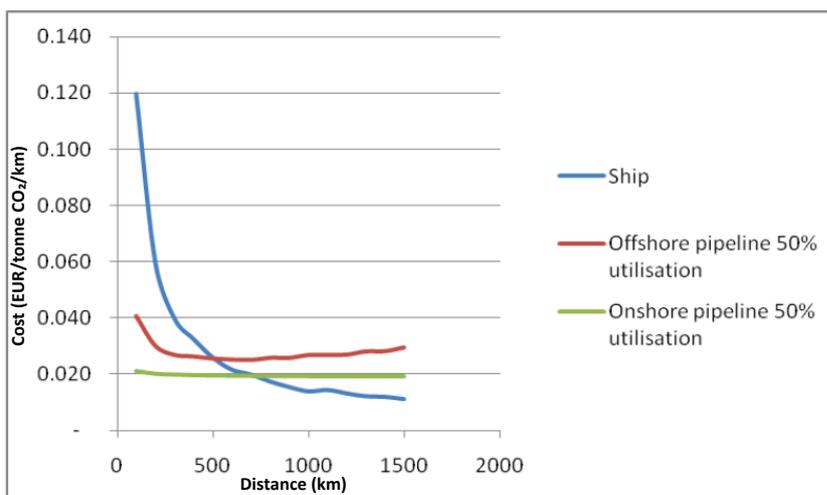
### Selection of transport form - influence of distance and capacity

Several studies have been conducted with relation to optimisation of transport of large volumes of CO<sub>2</sub> [1-6] in a CCS context. For transport of large volumes (>1 million tonne per annum (MTPA)) only pipeline and ship transport are viable transport options. Road transport is typically only considered for smaller volumes and for short distances when establishing a pipeline is not feasible.

Transport of CO<sub>2</sub> by ship and pipeline have different advantages and disadvantages.

In general, CO<sub>2</sub> transport by ship is a more flexible option than pipeline. For ships, the transportation route can easily be changed if another CO<sub>2</sub> source or storage site emerge, likewise the capacity of the transportation chain can be gradually upgraded by adding more ships if demands grow. Also ships (if a standard carrier type is selected), can be reused for transportation of other goods e.g. LPG, NH<sub>3</sub>, etc. in case the CO<sub>2</sub> source should cease production. CO<sub>2</sub> transport by ship is on the other hand more costly than pipeline transport for short to medium distances and it requires costly CO<sub>2</sub> terminals with intermediate storage facilities.

For transport of large volumes of CO<sub>2</sub> (and obviously for CO<sub>2</sub> point sources located inland away from waterways) CO<sub>2</sub> pipelines will be the more cost-efficient solution. In a study by ZEP [2] the cost of CO<sub>2</sub> transport for 10 MTPA has been compared between ship and pipeline as shown in Figure 3. With the chosen assumptions e.g. pipeline utilisation factor of 50%, it appears from Figure 1-3 that pipeline transport is economically favoured for transport distances up to 500-700 km, where after ship transport is the favoured option. It also appears that at very short distances the ship option becomes much more costly. This is related to the fact that the full CAPEX investment for the ship case (ship + terminals) is present even for short distances and that the ship will spend most time in harbour loading and unloading. Different assumptions such as smaller CO<sub>2</sub> transport volumes will however change the turnover point where ship transport becomes more favourable.



**Figure 3. Cost of CO<sub>2</sub> transport (EUR/tonne/km, 2010 cost level) by pipeline at 50% capacity and by ship at 100% capacity (including terminal) for 10 MTPA. Source: ZEP [2]**

The amount of energy and the associated CO<sub>2</sub> emission required for transporting CO<sub>2</sub> will clearly be dependent on the transport distance but also of the transport form. Pipeline transport will typically be the most energy efficient (less emission intense) mode of transportation and road truck the more emission intense.

In Table 2 an example is shown of the estimated CO<sub>2</sub> emission for 200 km transport of CO<sub>2</sub> by respectively pipeline, ship and truck using energy data from this catalogue. An important message from Table 2 is that although the CO<sub>2</sub> emission related to transportation varies significantly between the transport forms it constitutes only a small fraction of the transported amount of CO<sub>2</sub> even for a distance of 200 km.

**Table 2. Example of estimated CO<sub>2</sub> emission associated with transport of CO<sub>2</sub> for 200 km by different transport forms. Only CO<sub>2</sub> related to the energy (fuel and electricity) requirement for operation is considered. \*estimated as emission related to electricity consumption for pumping using 135 g CO<sub>2</sub>/kWh.**

	<i>Pipeline</i>	<i>Ship</i>	<i>Truck</i>
CO <sub>2</sub> emission in % of transported volume	0.05 %*	0.4 %	1.6%

In addition to cost, other factors such as regulation, safety, timeframe, and availability, public perception, etc. could influence the choice of CO<sub>2</sub> transport technology. For instances it may be difficult to establish a CO<sub>2</sub> pipeline through densely populated areas hence road tanker transport may be the preferred solution even though it will lead to increased transportation costs.

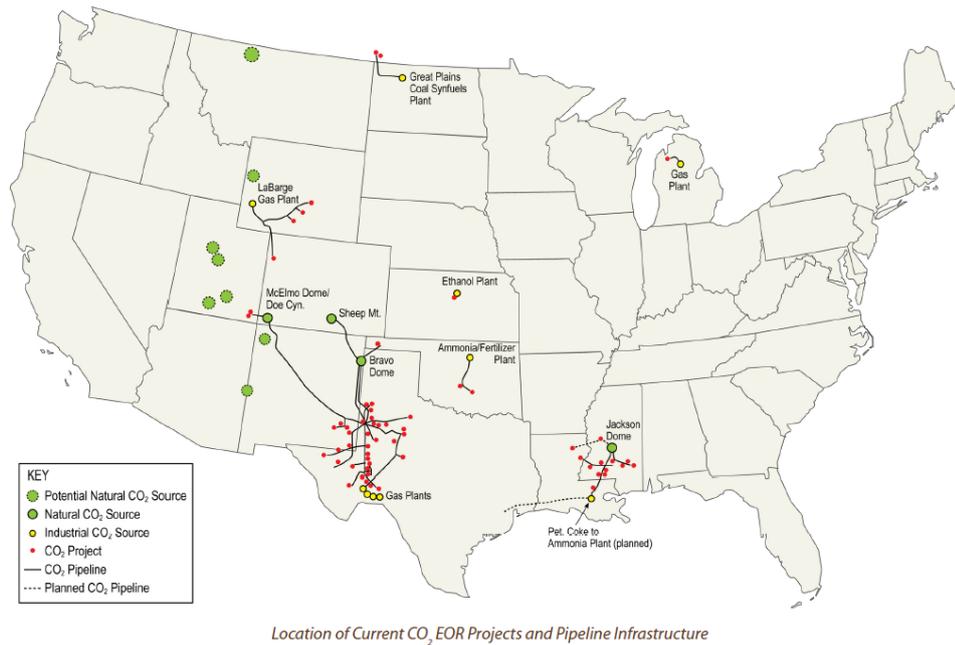
### CO<sub>2</sub> transport by pipeline

Transport of large volumes of CO<sub>2</sub> by onshore pipelines is today primarily known from USA and Canada although few CO<sub>2</sub> pipelines exist in Europe. Offshore CO<sub>2</sub> pipelines are few and the Norwegian Snøhvit CCS project is the best-known example.

The existing large CO<sub>2</sub> (transmission) pipelines all transport CO<sub>2</sub> in the dense phase region typically in the pressure region of 80-160 bar. Examples exist of CO<sub>2</sub> pipelines operating in the gaseous state at low pressure (<40 bar) or with liquid refrigerated CO<sub>2</sub>. However, these conditions are mainly used for short distance transport within processing plants or locally between different industries.

In USA several regional networks with CO<sub>2</sub> pipelines exists predominantly in the southern and southwestern states as well as north on the border to Canada. Main CO<sub>2</sub> pipeline infrastructure in USA is shown in Figure 4.

There are more than 50 individual CO<sub>2</sub> pipelines with a combined length of about 7000 km. The pipelines transport CO<sub>2</sub> from point sources to oil fields where it is injected and used for enhanced oil recovery (EOR). The installed CO<sub>2</sub> pipelines cover a broad range of diameters and lengths.



**Figure 4. Location of existing CO<sub>2</sub> pipeline infrastructure in USA [3]**

In the Netherlands a smaller CO<sub>2</sub> pipeline network exists to supply CO<sub>2</sub> from gas processing plants to large greenhouses for boosting the growth rates and yields of crops.

Table 3 lists examples of operational CO<sub>2</sub> pipelines with main data in America and Europe.

**Table 3. Examples of operational CO<sub>2</sub> pipelines [5].**

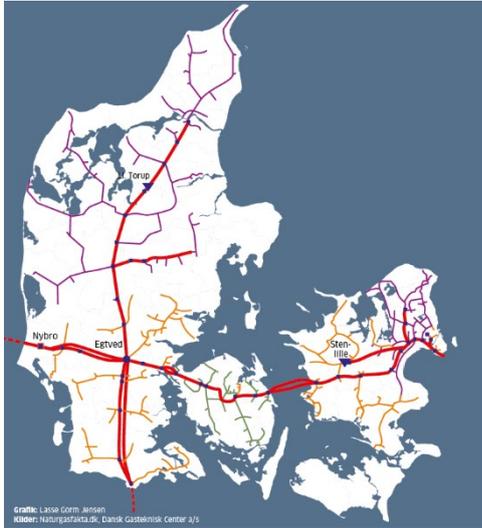
Name	Country	CO <sub>2</sub> capacity (MTPA)	Length (km)	Diameter (mm)
Weyburn	Canada	2.0	330	305-356
Saskpower Boundary Dam	Canada	1.2	66	
OCAP	The Netherlands	0.4	97	
Snøhvit (offshore)	Norway	0.7	153	
Bati Raman	Turkey	1.1	90	
Cortez	USA	24	808	762
Central Basin	USA	27	232	406
Monell	USA	1.6	52	203
Sheep Mountain Operational	USA	11	656	656
Slaughter	USA	2.6	56	305
West Texas	USA	1.9	204	203-305

**Possibility of reusing the existing natural gas network for CO<sub>2</sub> transport**

In Denmark there is an existing natural gas (NG) transmission and distribution network as described in chapter 112 Natural Gas Distribution Net of the Technology Catalogue.

In a future fossil free Denmark one can speculate in reusing the NG network or parts of it for CO<sub>2</sub> transport.

The NG network is designed for 80 bar operating pressure at the gas transmission lines and 40 bar at the main distribution lines. Secondary distribution lines have design pressure of below 20 bar. MR (Metering and Reduction) stations maintain the various pressure levels at the distribution net whereas the underground gas storage and interconnections maintain the pressure in the main transmission lines. A map of the NG network is shown in Figure 5.



**Figure 5. Natural gas pipeline network (steel piping) in Denmark. Source: Naturgasfakta.dk, DGC.**

Considering dense phase pipeline transportation of CO<sub>2</sub> as described in previous section where operational pressures are typically in the range of 80-160 bar (above critical pressure) the max operating pressure of the NG system is too low when considering operational margins and pressure drop. The existing NG network is therefore not suitable for dense phase CO<sub>2</sub> transport.

Another possibility is to operate the pipeline network at relatively low CO<sub>2</sub> pressure in the gaseous state. For expected operating temperatures of buried pipeline i.e. down to 5°C, liquid phase may form at 40 bar. Hence to stay out of the two-phase region, pressures up to say 30 bar could be acceptable. At 30 bar the CO<sub>2</sub> density is reduced to approx. 80 kg/m<sup>3</sup>, greatly decreasing the transportation capacity compared to dense phase 800-1000 kg/m<sup>3</sup> operation. Considering that the pipelines of the NG network is designed for gas transport, the capacity of the main transmission lines are still capable of transporting several MTPA CO<sub>2</sub> even at 30 bar, which may be sufficient in most scenarios.

The NG pipe network is constructed of carbon steel with small distribution lines of polymer. Carbon steel will be compatible with CO<sub>2</sub> as long as the CO<sub>2</sub> is maintained dry. Any compression and MR station will have to be upgraded to deal with the different physical properties of CO<sub>2</sub>. Thus, from an overall technical point-of-view reuse of NG pipelines for CO<sub>2</sub> transport at low pressure conditions (<40 bar) seems feasible although this will need to be evaluated in greater details.

Other specific stretches of oil and gas pipelines may also become redundant when production from the Danish oil and gas fields in the North Sea is phased out or the general use of oil and gas diminishes. The possible reuse of these for CO<sub>2</sub> transport will have to be evaluated on a case by case basis

considering remaining lifetime, design pressure and required modifications. Reuse of oil and gas pipelines for CO<sub>2</sub> transport has also been considered in other projects e.g. OCAP project in the Netherlands [6].

### CO<sub>2</sub> transport by ship

Transport of CO<sub>2</sub> by ship is as previously mentioned feasible for medium to long transport distances of medium to large amounts of CO<sub>2</sub>. CO<sub>2</sub> will be transported in liquid state and to some extent refrigerated in order to obtain high transport density and modest pressure level. Transport of CO<sub>2</sub> at high pressure and closer to ambient temperature is also possible but will require a special ship design and is likely to increase the weight of the ship's pressure tanks relative to cargo. Typically, a CO<sub>2</sub> terminal with interim storage tanks will be required at one or both ends. The required storage capacity will be dependent on the actual operating philosophy and specific design conditions of the transportation chain. The terminals will typically be designed with loading pumps, transfer lines, marine loading arms, metering and re-liquefaction plant for handling of boil-off gasses from storage tanks, etc.

Today no large-scale CCS/CCU project employing ship transport of CO<sub>2</sub> is operational. However, experience exists with ship transport of smaller volumes of liquid CO<sub>2</sub> for industrial consumers around Europe.

- **Experience with CO<sub>2</sub> transport by ship in smaller scale:** The Norwegian fertilizer producer Yara has for more than 20 years operated a small fleet of CO<sub>2</sub> carriers (Yara has today sold-off its CO<sub>2</sub> business, now Nippon gases) between CO<sub>2</sub> recovery facilities (at ammonia plants) and CO<sub>2</sub> terminals around Europe. The ships have been relatively small units as shown in Figure 6 of 1000-1800 t CO<sub>2</sub> cargo capacity. Some of the CO<sub>2</sub> carriers have been converted dry cargo ships. The CO<sub>2</sub> transport conditions have been liquid CO<sub>2</sub> at 15-18 bara and -25 to -30°C. Today, these conditions are sort of a “standard” for transport and supply of industrial grade liquid CO<sub>2</sub>.



Figure 6. M/T Yara Gas III liquid CO<sub>2</sub> carrier. [7]

- **CCS studies involving ship transport of large volumes of CO<sub>2</sub>:** Several studies of CCS projects have considered transport of liquid CO<sub>2</sub> by ship. Ship sizes in the range of 2,000 to 100,000 m<sup>3</sup> CO<sub>2</sub> cargo have been considered [1, 4, 8, 9, 11, 12, 13]. The studies consider different CO<sub>2</sub> transport conditions and ship designs. In many studies custom built CO<sub>2</sub> ships are considered, however it is also widely considered to use a standard gas carrier ship for CO<sub>2</sub> transport. Semi-refrigerated gas carriers used for LPG, ammonia, propylene and other chemicals have typically operating pressures up to 6-8 bar and operating temperatures down to -50°C. Such vessels may transport liquid CO<sub>2</sub> at 7 bar and -50°C. Standard semi-refrigerated gas carriers are normally not equipped with refrigeration machinery, hence the pressure and temperature of the liquid CO<sub>2</sub> will rise slightly during transport. The former shipping company IM Skaugan (now bankrupt) operated a fleet of semi refrigerated gas carriers in the capacity range of 8-10,000 m<sup>3</sup>, which had been approved for transport of CO<sub>2</sub> [4]. LPG ships may however not be the optimal ship for CO<sub>2</sub> transport because liquid CO<sub>2</sub> has twice the density of LPG implying that the volume capacity may be reduced if transporting CO<sub>2</sub> [9].
- **CCS demonstration project with CO<sub>2</sub> ship transportation:** The CO<sub>2</sub> storage and transportation part of the Norwegian full-scale CCS demonstration project named “Langskip” have studied ship transport of CO<sub>2</sub> from capture plant sites at Oslo and Brevik to a receiving terminal at the Norwegian west coast. Several different ship sizes and classes have been studied [10, 12]. Liquid CO<sub>2</sub> at 15-18 bar and -25-30° has been selected as the transport conditions in the project i.e. similar to the standard industrial grade. The project has concluded to base the ship design (newbuilt ship) on a concept that closely resembles that of fully pressurised LPG vessels instead of a special design. The 15-18 bar operating pressure is above typical specification of a semi-refrigerated vessels hence the fully pressurised carrier with design pressure of 20 bar is selected. Fully pressurised LPG vessels do normally operate with the cargo at ambient temperature hence does not necessarily have insulated tanks suitable for refrigerated liquid CO<sub>2</sub>. The project reports of about 18 months construction time for such vessels.

### CO<sub>2</sub> transport by road

Today road transport of liquid CO<sub>2</sub> by tanker truck is common from distribution hubs to industrial consumers. Standard sizes for CO<sub>2</sub> semi-trailers are available from different vendors e.g. ASCO [14]. Trailers with capacities up to 25-30 m<sup>3</sup> liquid CO<sub>2</sub> is typical. CO<sub>2</sub> semi-trailers are pulled by standard trucks as shown in Figure 7.

With tanker truck, liquid CO<sub>2</sub> is transported at 15-18 bar and -25 to -30°C i.e. the industry standard conditions. The density of liquid CO<sub>2</sub> at these conditions is around 1070 kg/m<sup>3</sup>. CO<sub>2</sub> trailer tanks are typically insulated by PUR foam or vacuum insulated to keep the CO<sub>2</sub> cool during transport. Trucks are typically not equipped with a re-refrigeration unit, hence temperature and pressure of the CO<sub>2</sub> may rise slightly during transport. Truck loading/unloading bays for liquid CO<sub>2</sub> and CO<sub>2</sub> transferring equipment is required at terminals receiving tanker trucks. Standard terminals for truck loading/unloading are commercially available.

Transportable ISO-tank-containers for liquid CO<sub>2</sub> are also available [14].

Considering the above road transport of CO<sub>2</sub> are relatively similar to that of liquid fuels or other pressurised gasses.



Figure 7. CO<sub>2</sub> semi-trailer from ASCO. Source; [www.ascoco2.com](http://www.ascoco2.com)

### CO<sub>2</sub> transport by rail

CO<sub>2</sub> transport by rail is technically possible and cryogenic rail cars (see Figure 8) are in use some places in the world today for distribution of liquid CO<sub>2</sub> to industrial users. However, there are no examples where rail cars are used for transportation of large amounts of CO<sub>2</sub> in a CCS value chain. In a Danish context where very few emission sources are linked to the railroad network it is difficult to imagine that rail transportation of CO<sub>2</sub> will ever play a significant role. This option is therefore not described any further in this catalogue.



Figure 8. Railroad car for liquid CO<sub>2</sub> transport. Source: [www.VTG.com](http://www.VTG.com)

### CO<sub>2</sub> interim storage

Interim storage of CO<sub>2</sub> may be required in connection with CO<sub>2</sub> transportation from source to end destination. This will mainly be relevant when CO<sub>2</sub> is transported in liquid form by truck or ship. The interim storage is needed to buffer the continuous recovery/offtake of CO<sub>2</sub> from capture or utilisation plants between individual truck and ship loads.

As a result, the required capacity for interim storage will largely be governed by the cycle time of the tanker trucks or ships and the desired buffer capacity.

For pipeline transport alone from capture plant to end destination e.g. underground storage, interim storage of CO<sub>2</sub> will typically not be required.

Today liquid CO<sub>2</sub> is most commonly stored in bullet tanks or clusters of tanks of varying height and diameter. Tanks can both be vertically and horizontally oriented depending on local constraints. Bullet tanks are typically fabricated at workshops/shipyards and transported fully insulated and dressed to installation site. The maximum size of storage tanks will hence be limited by what is practical to transport. For smaller capacities (below 100 m<sup>3</sup>) standard liquid CO<sub>2</sub> tanks are available from vendors of industrial gases. These tanks are typically vacuum insulation and have double shell. Bullet tanks can be fabricated with unit size of 1000 m<sup>3</sup> or more, however these are too big for road transport and will require that the installation site has good access to a harbour. For CO<sub>2</sub> terminals with storage capacities of several 1000 m<sup>3</sup> the interim storage will consist of multiple tanks. Site assembly of large tanks is very expensive and rarely the preferred option.

Figure 9 and Figure 10 show examples of tank farms for interim storage of liquid CO<sub>2</sub> at medium pressure typical storage conditions.



**Figure 9. Storage for 3300 tons liquid CO<sub>2</sub> at Yara's ammonia plant in Porsgrunn, Norway in conjunction with CO<sub>2</sub> export terminal (now operated by Nippon Gases Norway) [7]**



**Figure 10. Liquid CO<sub>2</sub> import terminal with truck filling bays operated by Yara (now Nippon Gases Norway). [7]**

## Examples of CO<sub>2</sub> transportation chains

To illustrate the different elements of CO<sub>2</sub> transportation and how these can be assembled to create the desired transportation chain a set of examples have been compiled as shown in the following.

### Example 1 - Transport of CO<sub>2</sub> by road tanker and ship

This example illustrates how CO<sub>2</sub> can be transported from CO<sub>2</sub> source to offshore storage site. For a small to medium size CO<sub>2</sub> emission source located inland, the best CO<sub>2</sub> transport option may be truck transport to a nearby harbour and ship transport to offshore storage or receiving terminal. As an example, this could be a Waste-to-Energy (WtE) plant with 25 t CO<sub>2</sub>/h CO<sub>2</sub> capture or 200,000 tpa. A liquefaction plant is included in the carbon capture facility.

The different elements required for the CO<sub>2</sub> transport chain is as listed below and shown in Figure 11:

- CO<sub>2</sub> interim storage at capture site e.g. 1000 t CO<sub>2</sub>
- CO<sub>2</sub> transport by tanker truck. Capacity 30 t CO<sub>2</sub>/truck indicating 20 truckloads per day
- CO<sub>2</sub> export terminal with interim storage, e.g. 4000 t CO<sub>2</sub> storage
- CO<sub>2</sub> carrier (ship) of 4000 t CO<sub>2</sub> capacity indicating one ship departure every 6 days (cycle time).
- Transfer of CO<sub>2</sub> from ship to injection vessel/platform for underground storage (CO<sub>2</sub> storage is not included in this chapter of the catalogue. The CO<sub>2</sub> carrier may be equipped with facilities for conditioning and injection of CO<sub>2</sub> into a reservoir, but this is not considered here)

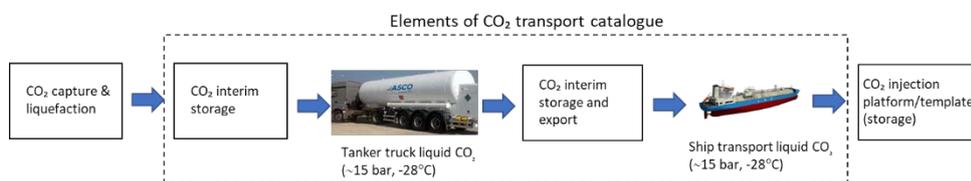


Figure 11. CO<sub>2</sub> transport by road tanker and ship to storage site/import terminal.

### Example 2 - Transport of CO<sub>2</sub> by pipeline to offshore storage

This example illustrates how CO<sub>2</sub> from a large point source can be transported in pipeline to an offshore storage site. For a large point source say 1 MTPA of CO<sub>2</sub> capture, pipeline transport may be the more attractive solution. In this example it is assumed that CO<sub>2</sub> will have to be transported 50 km in a pipeline onshore before the pipeline goes offshore and proceeds further 30 km to the storage reservoir offshore. The compression plant is included in the carbon capture facility and will deliver CO<sub>2</sub> at the pipeline interface at 150 bar. However, because of the pressure drop in the pipeline say 1 bar/km, and the requirement for high injection pressure, a pumping station for boosting of pressure is included just before the pipeline goes offshore.

In this case, the different elements required for the CO<sub>2</sub> transport chain is as listed below and shown in Figure 12:

- 50 km onshore CO<sub>2</sub> pipeline from capture site to coast. Capacity of 1 MTPA or 120 t CO<sub>2</sub>/h requires an 8" pipeline

- CO<sub>2</sub> pumping station to increase pressure to 150 bar
- 30 km offshore CO<sub>2</sub> pipeline to CO<sub>2</sub> injection template (wellhead)

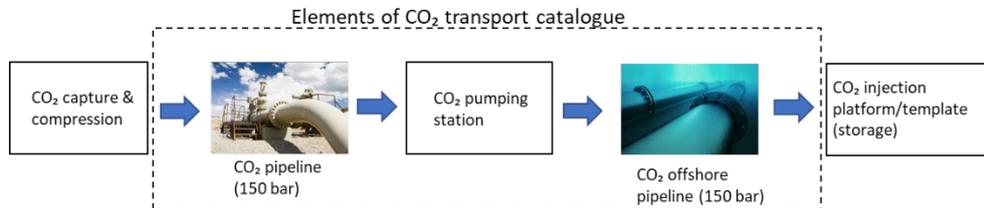


Figure 12. CO<sub>2</sub> transport by onshore and offshore pipeline to storage location.

### Example 3 – Transport of CO<sub>2</sub> by pipeline and ship

In this example CO<sub>2</sub> is transported 20 km from a relatively big capture facility (50 t/h or 400,000 tpa) by pipeline to a CO<sub>2</sub> export terminal where it is liquefied and temporarily stored before transported by ship to end destination. This is relevant in the case the CO<sub>2</sub> source is located at distance from the sea and the conditions are in favour of pipeline transport instead of truck i.e. relatively big CO<sub>2</sub> source. The compression plant included in the carbon capture facility will deliver CO<sub>2</sub> at pipeline interface at 150 bar. The distance to the CO<sub>2</sub> export terminal will not be great enough to require a pumping station on the route.

The different elements required for the CO<sub>2</sub> transport chain is as listed below and shown in Figure 13:

- 50 t CO<sub>2</sub>/h is transported by 30 km onshore pipeline (6 or 8" pipeline)
- CO<sub>2</sub> export terminal with liquefaction plant and interim storage for 5000 t CO<sub>2</sub>.
- CO<sub>2</sub> carrier (ship) of 4000 t CO<sub>2</sub> capacity

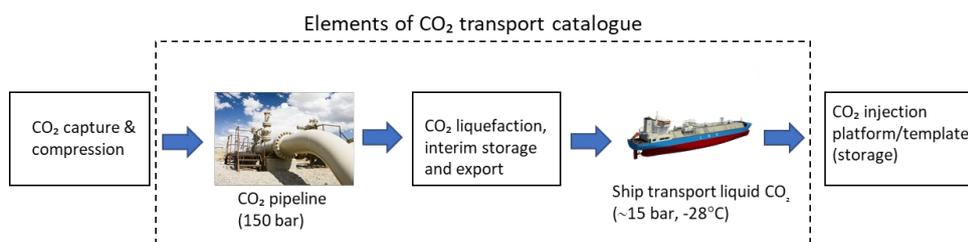


Figure 13. CO<sub>2</sub> transport by pipeline followed by liquefaction interim storage and ship transport.

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## 121 CO<sub>2</sub> transport in pipelines

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Date	Ref.	Description
-	-	-

## Qualitative description

### Brief technology description

CO<sub>2</sub> pipelines are relevant for transport of large volumes of CO<sub>2</sub> such as from large point source emitters to storage sites, export terminals or CO<sub>2</sub> utilisation facilities.

As explained in the introduction the standard concept for long distance (say above 10-30 km) CO<sub>2</sub> pipeline transport today is dense phase CO<sub>2</sub> transport at the conditions shown in Figure 1. Therefore, only this transport form is considered in the catalogue.

Dense phase operation is regarded as operating pressures above the critical pressure of CO<sub>2</sub> (73 bar). With operational and safety margins, the minimum operating pressure is selected as 80 bar. The maximum operating pressure of CO<sub>2</sub> pipelines is selected as 150 bar. This is a compromise between securing adequate operating range (allowance for pressure drop) and keeping the pipe wall thickness (piping cost) at reasonable level. The density of dense phase CO<sub>2</sub> will only increase weakly with pressure above 150 bar at relevant temperatures (5-20°C) as shown in Figure 2, hence there is limited process benefits of operating with higher pressures except from potential longer distances between compression/pumping stations. In addition, it is expected that the permitting process may become increasingly complicated at higher pressures (increased consequence if ruptured), which is also a factor that must be considered.

Several design standards exist for CO<sub>2</sub> pipelines. In Europe DNV-RP-J202 and ISO 27913:2016 are relevant.

The initial compression of CO<sub>2</sub> up to 150 bar and drying to pipeline specifications are included in the scope of the CO<sub>2</sub> capture plant and explained in the Carbon Capture Catalogue. The CO<sub>2</sub> compressor will hence control the pressure at the inlet side of the pipeline. During outages of the compressor isolation valves will isolate the pipeline hence it is maintained pressurised. Isolation valves are also

expected along the pipeline (onshore) in order to seal off segments in case of leakages. The allowable distance between isolation valves will depend on a risk assessment of each segment. In populated areas isolation valves is expected to be required more frequently than in rural areas. Typical distances between isolation valves onshore are 10-20 km [15]. Offshore pipelines will typically not have isolation valves between the beach and the wellhead.

For CO<sub>2</sub> pipelines it is not expected that metering stations will be relevant along the route but will be located together with the compression plant at the inlet or at the end of the pipe. This is of course dependent on the pipeline configuration, i.e. whether it is a pipeline network or point to point pipeline.

Compression/pumping stations may be relevant along the route to overcome frictional loss. As CO<sub>2</sub> is in dense phase the pressure can be increased by centrifugal or reciprocating pumps which are significantly cheaper than compressors and consume much less energy. A compression/pumping station will be required if the pressure drops below the minimum pipeline operating pressure (80 bar). Typically, this may be every 70-140 km. It is expected that the pumps will be located in dedicated stations/houses along the route.

For offshore pipelines, compression/pumping stations are not applicable. Therefore, the dimension of the pipeline will have to be selected hence the pressure drop is acceptable without pressure boosting. In general, this implies that the pipeline diameter increases with length of the pipeline for the same transportation capacity [2].

### **Input**

Input is dense phase CO<sub>2</sub> at the specified inlet conditions.

Energy is required in the form of pumping/compression work to overcome the frictional loss in the pipeline (pressure drop).

### **Output**

This is same as the input as no CO<sub>2</sub> is vented or consumed along the pipeline. The CO<sub>2</sub> will exit at lower pressure due to the pressure drop in the line.

### **Efficiency and losses**

Energy loss from CO<sub>2</sub> pipeline transportation occurs as a result of fluid frictional loss (pressure drop) in the pipelines. The energy loss for CO<sub>2</sub> pipeline transport is a strong function of fluid velocity (approximately third power), therefore the extent of energy loss will be determined by the design velocity of the pipeline. This is ultimately a trade-off between capital cost (pipeline diameter) and operating cost (pumping energy).

For the technology catalogue CO<sub>2</sub> fluid velocities of 1-2 m/s has been applied for the pipelines resulting in pressure drop of approx. 0.5-1.5 bar/km. Highest pressure drop (1.5 bar/km) is tolerated for the smaller pipeline diameters (10-30 t CO<sub>2</sub>/h) because it is anticipated that the small bore pipeline is used for relative short distances.

In addition, energy is required at terminals if CO<sub>2</sub> has to be transformed from dense phase fluid to liquid CO<sub>2</sub> at intermediate storage/ship transport conditions. However, the energy requirement (loss) at terminals is included as a separate post.

### Application potential

Pipelines will be applicable for point to point transport of CO<sub>2</sub> e.g. from one capture site to one storage or utilisation site, or as part of a larger pipeline network or CO<sub>2</sub> hub.

### Typical capacities

The existing CO<sub>2</sub> pipelines in operation covers a large capacity range from 0.06 to 27 MTPA. Pipeline diameters from 4" to 30" have been deployed.

In a Danish context, CO<sub>2</sub> pipeline transport is not likely to exceed around 5-10 million tonnes per annum (MTPA) as this will cover many of the largest point sources of CO<sub>2</sub>. The smallest capacity that will be relevant for pipeline transport will of course depend on a lot of factors such as the distance and location. However as the engineering and installation costs do not scale down proportionally for small bore pipelines it is expected that truck transport will be favoured over pipeline transport at low capacities (e.g. below about 50-100 kton CO<sub>2</sub> per year). For very short distances e.g. few km's, over open (rural) terrain pipeline transport could still be an attractive solution even for small volumes.

### Advantages/disadvantages

The main advantages with pipelines are that large volumes can be transported at low operating costs, with low energy consumption (and CO<sub>2</sub> emission), no occupation of existing infrastructure (roads, harbours, etc.) as well as continuous operation independent on weather conditions and other external disruptions.

Disadvantages with pipeline transport are high investment cost, long planning and construction time, extensive approval procedures i.e. construction within city limits is difficult, land purchase issue, public perception and low flexibility (end-use value) if CO<sub>2</sub> source disappears or is relocated.

### Environmental and safety

#### Environment

The construction phase of a pipeline may have substantial environmental impact depending on the chosen route. An environmental impact assessment (VVM) will be required. It is likely that future CO<sub>2</sub> pipelines will be constructed as part of an integrated CCS or CCU project, hence the environmental impact assessment will cover the entire project.

Once the pipeline is constructed it will only have marginal environmental impact. CO<sub>2</sub> losses from pipeline will not occur during ordinary operation. Blow down of pipeline sections for maintenance or repair work is likely in the operational phase, however as long as the blow down rate is slow and controlled it will have insignificant environmental impact.

### **Safety**

As CO<sub>2</sub> is a non-flammable but asphyxiant gas which becomes harmful at higher concentrations. Safety must be an integral part of a pipeline project from design to operational phase. Risk assessment of exposure of people to CO<sub>2</sub> from accidental leakages has to be performed and suitable risk mitigating measures need to be implemented. This may include proper leak detection systems (monitoring for sudden pressure drop), CO<sub>2</sub> sensors at relevant locations and low points, sectionalisation (isolation valves) or ESD valves to limit accidental releases, automatic monitoring and shutdown functions.

If a high-pressure CO<sub>2</sub> pipeline is rapidly depressurised to atmospheric pressure CO<sub>2</sub> will form a mixture of solid and gaseous CO<sub>2</sub> at -78°C. This may create a cloud of heavy CO<sub>2</sub> gas which will flow to low points in the terrain. Depending on weather conditions and local turbulence a CO<sub>2</sub> cloud may disperse quickly or be present for several minutes. A risk assessment concerning exposure of third party in the event of rupture will have to be performed as part of the engineering phase. For a CO<sub>2</sub> pipeline there will be operational risks related to CO<sub>2</sub>'s phase behaviour and load fluctuations e.g. liquid phase or dry ice formation during sudden drops in pressure, freezing of safety valves, etc. Maintenance stops with full depressurization will have to be conducted at a slow pace in order to prevent freezing.

The safety of natural gas pipelines and related installations will be evaluated by the Working Environment Authority in Denmark. It is not precisely known which authority that will evaluate future CO<sub>2</sub> pipelines and what the safety requirements will be.

### **Monitoring**

In daily operation flow, pressure and temperature of CO<sub>2</sub> pipelines must be continuously monitored. The readings from field instruments shall be transferred to a manned control room.

Buried pipelines are also normally equipped with cathodic protection system for monitoring of external corrosion. The pipeline will also be equipped with provisions for pig launchers and receivers (cleaning and inspection device) hence intelligent pigging can be performed for inspection and assessment of internal corrosion and fouling. Because only clean, dry CO<sub>2</sub> gas will be transported in the pipelines, fouling and internal cleaning will probably be less significant compared to the natural gas pipelines.

CO<sub>2</sub> compression/pumping houses, metering house, valve pits or other places where leaking CO<sub>2</sub> can accumulate to dangerous concentrations will be equipped with CO<sub>2</sub> detectors and alarms.

Flow in and out of the pipelines are to be determined by fiscal metering hence adequate control exist on volumes transferred between different parties (e.g. emission source owner and transport/storage provider). Monitoring of the CO<sub>2</sub> quality e.g. moisture content, O<sub>2</sub> content and other trace impurities will probably be a requirement at the inlet, hence it is ensured that the CO<sub>2</sub> quality is compatible with pipeline design materials and downstream specifications.

### **Research and development perspectives**

Pipeline transport of CO<sub>2</sub> and other pressurized fluids is a mature and commercially available technology (TRL 9). Little technical development potential for pipeline transport is expected.

## Prediction of performance and costs

### CAPEX

For onshore pipelines COWI has made its own estimate of the investment cost based on inhouse experience obtained from engineering, procurement and installation of natural gas transmission lines in Denmark taking into account expected cost differences related to CO<sub>2</sub> specific design conditions e.g. higher pressure, safety factor, etc. The own estimate is benchmarked against references from the literature.

The following assumptions are applied for estimate of CO<sub>2</sub> pipeline investment cost:

- Point to point pipeline (no compressors or conditioning equipment included)
- Pipe dimensioned for 150 bar using a safety factor of 0.2 (conservative). Pipeline construction material is carbon steel (extra strong) with polymer coating. Cathodic protection is included.
- Unit cost based on pipeline distance of 50-100 km in rural area. For very short pipelines the unit cost will increase. This effect is not captured in the estimates.
- Pipeline dimensioned for pressure drop of 0.5 to 1.5 bar/km where the highest pressure drop is accepted for the smallest diameter. The corresponding pipeline flow velocities are in the range of 1.2-2 m/s.
- 3 different pipeline dimensions namely 4, 8 and 12" are priced and used as cost basis for the 3 capacity intervals provided in the data sheet:
  - The 4" pipeline will represent CO<sub>2</sub> flow capacity of 10-30 t CO<sub>2</sub>/h and the specified unit cost in the data sheet (15 EUR/[t CO<sub>2</sub>/h]/m) is related to a flow rate of 20 t CO<sub>2</sub>/h.
  - For pipeline capacity of 30-120 t CO<sub>2</sub>/h the cost is based on unit costs for the 4 and 8" pipelines where the 4" has weight of 1/3 and 8" of 2/3. The unit cost of the 8" pipeline is related to a flow rate of 120 t CO<sub>2</sub>/h.
  - For pipeline capacity of 120-500 t CO<sub>2</sub>/h the cost of the 12" pipeline is applied. The unit cost in the data sheet (2.3 EUR/[t CO<sub>2</sub>/h]/m) is related to 300 t CO<sub>2</sub>/h flow rate.
- Sectionalisation vales (ESD) with ancillaries every 15 km is assumed. This is uncertain as regulative requirements for CO<sub>2</sub> pipelines in DK is unclear.
- Installation cost includes trenching and 8 % for controlled drilling, permitting and environmental investigations
- Cost factor for engineering and follow-up added (6 to 10% depending on size).

Table 1 shows the estimated pipeline cost for a 12" pipeline per unit of distance (km) and capacity (t CO<sub>2</sub>/h). Also shown are estimates for onshore pipeline of similar dimension from the ZEP CO<sub>2</sub>

transportation study [2]. It appears that the estimated pipeline cost is a bit lower, but in relatively good agreement with estimates from ZEP. It shall be remarked that the ZEP estimate is not specific for Danish conditions, but also based on rural area and non-challenging ground conditions [2].

**Table 1. Investment cost estimates for onshore CO<sub>2</sub> pipeline in rural area and compared to ZEP estimate. Both estimates do not include upstream CO<sub>2</sub> compression or pressure booster stations. ZEP estimate is not specific for Danish conditions.**

	COWI estimate	ZEP study [2]
<b>OD Pipe size</b>	12"	12"
<b>CO<sub>2</sub> capacity (MTPA)</b>	2.5	2.5
<b>Pipeline length (km)</b>	50-100	10 and 180
<b>Total installed cost (EUR/km/[t CO<sub>2</sub>/h])</b>	2.3	2.8 (180 km) 3.9 (10 km)

For offshore pipeline, the CAPEX is based on ZEP-s estimate [2] for 180 km 12" pipeline transporting 2.5 MTPA CO<sub>2</sub> (approx. 300 t CO<sub>2</sub>/h) but reduced from 4.7 to 4.0 EUR/[t CO<sub>2</sub>]/m to be more in line with expectations for Danish conditions and the estimate for onshore pipeline.

#### OPEX

The O&M value is based on ZEP value of 6000 EUR/km for 12" onshore pipeline transporting 2.5 MTPA CO<sub>2</sub> [2]. This corresponds to approx. 20 EUR/km/[t CO<sub>2</sub>/h]. The estimate excludes maintenance and energy cost for the initial CO<sub>2</sub> compression as this is included with the capture plant. The cost is assumed to be fixed O&M cost independent on capacity factor. The variable O&M cost is assumed to be negligible.

#### Levelized cost of CO<sub>2</sub> pipeline transport

For benchmarking of inhouse pipeline CO<sub>2</sub> transport cost to literature values an example with transport of 2.5 MTPA for 250 km is calculated as shown in Table 2.

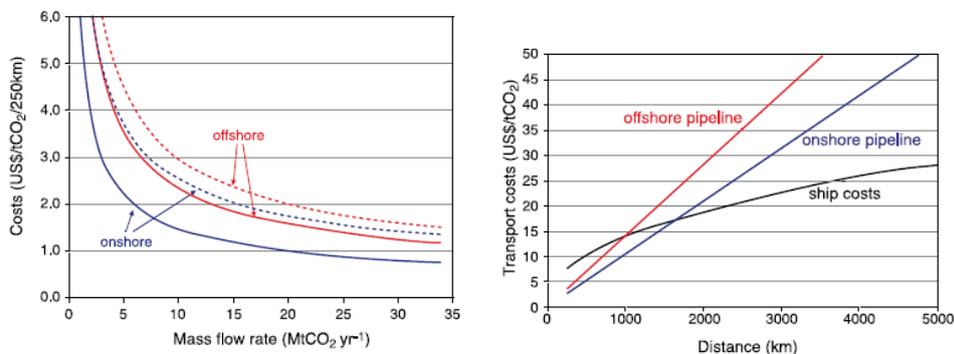
**Table 2. Example of cost of CO<sub>2</sub> transport. Cost is based on 250 km 12" pipeline operating at full capacity (8400 hrs/year).**

Parameter	Cost	Comment
<b>CAPEX 250 km 12" pipeline</b>	173 mill EUR	Unit cost of 2.3 from catalogue
<b>1 x pumping station</b>	4.0 mill EUR	ΔP is 0.5 bar/km, total ΔP is therefore 125 bar => 1 pumping station
<b>Annual. CAPEX (6%, 50 year)</b>	11.2 mill EUR/year	50 years lifetime
<b>Fixed O&amp;M</b>	1.5 mill EUR /year	
<b>Power cost</b>	0.50 mil EUR/year	0.02 kW/km/[t CO <sub>2</sub> /h] and 40 EUR/MWh
<b>Total annual cost</b>	13.2 mil EUR/year	
<b>Annual CO<sub>2</sub> transport</b>	2.52 mill t CO <sub>2</sub> /year	8400 hrs at 300 t CO <sub>2</sub> /h (full capacity assumed)
<b>Specific transport cost</b>	<b>5.3 EUR/t CO<sub>2</sub></b>	

In IPCC's carbon capture and storage report from 2005 [4] CO<sub>2</sub> transportation costs have been assessed for onshore and offshore pipelines (and ship) as shown in Figure 2-1.

From Figure 1 (left) the cost of transport of 2.5 MTPA for 250 km can be read to about 4 USD/t CO<sub>2</sub> (2005 cost level), which is close to 4 EUR/t CO<sub>2</sub> in 2020 level (20% escalation and 1.24 USD/EUR). The

estimated value for Danish conditions is shown in Table 2 to be 5.3 EUR/t CO<sub>2</sub>, which is higher but in the same order of magnitude as the ICCP value.



**Figure 1.** Cost of pipeline transport from ICCP study from 2005 [4]. Figure to the left assume fixed pipeline length of 250 km. Figure to the right is for transport of 6 MTPA CO<sub>2</sub>.

In the ZEP report [2], the levelized cost of CO<sub>2</sub> transport for 180 km onshore pipeline is estimated to 5.38 EUR/t CO<sub>2</sub> using different CAPEX annualization parameters (8%, 40 years). With similar CAPEX parameters the estimated cost for Danish conditions will increase to 6.7 EUR/t CO<sub>2</sub>.

### Uncertainty

No CO<sub>2</sub> pipelines have been constructed in Denmark hence there will be uncertainty related to the permitting process and safety requirements. It is however likely that the procedures and rules will be relatively similar to what is known from NG pipelines. The uncertainty on specific safety requirements will add some uncertainty to the cost estimates.

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### Quantitative description

See separate Excel file for Data sheet

## 122 CO<sub>2</sub> transport by ship

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Date	Ref.	Description
-	-	-

### Brief technology description

Ship transport of CO<sub>2</sub> is most relevant for transport of medium to large volumes of CO<sub>2</sub> over medium to long distances e.g. from large point source emitters to offshore storage destination or land-based terminals. Ships do however also have the flexibility to operate in a route network picking up CO<sub>2</sub> from multiple locations. In this case ship may be relevant for relatively short transport distances.

As described in the introduction, only limited volumes of CO<sub>2</sub> is transported by ship today and in relatively small ships 1000 – 2000 m<sup>3</sup>.

For ship transport only liquid CO<sub>2</sub> is considered. Most studies in the literature considers modest pressure levels (<20 bar) as this will ensure high CO<sub>2</sub> density without requiring too heavy pressure tanks. However, examples of higher pressure alternatives have also been considered [12, 13]. Thus, the transportation conditions can be grouped in the following three alternatives:

- Low pressure conditions: Around a few bar above the triple point (5.2 bara, -56°C) say 6-8 bara and approx. -50°C. These conditions will result in the highest CO<sub>2</sub> density 1150 kg/m<sup>3</sup> and lowest thickness of pressure tanks. The low temperature will however require more comprehensive (expensive) insulation and use of low-temperature steel types.
- Medium pressure conditions: 15-18 bara and -25 to -30°C (The most common conditions for transport of liquid CO<sub>2</sub> today). This is a CO<sub>2</sub> density around 1070 kg/m<sup>3</sup>.
- High pressure conditions: 40-50 bara and +5 to +15°C. CO<sub>2</sub> density of 800-900 kg/m<sup>3</sup>. This alternative will require pressure vessels with higher design pressure (heavier per volume CO<sub>2</sub>) but less insulation is needed.

The ship design will be different for the different transport conditions. The selection of CO<sub>2</sub> transport conditions will also affect the export terminal design and the CO<sub>2</sub> liquefaction plant to some extent. Examples of design and pressure tank layout of CO<sub>2</sub> carrier ships are shown in Figure 1.

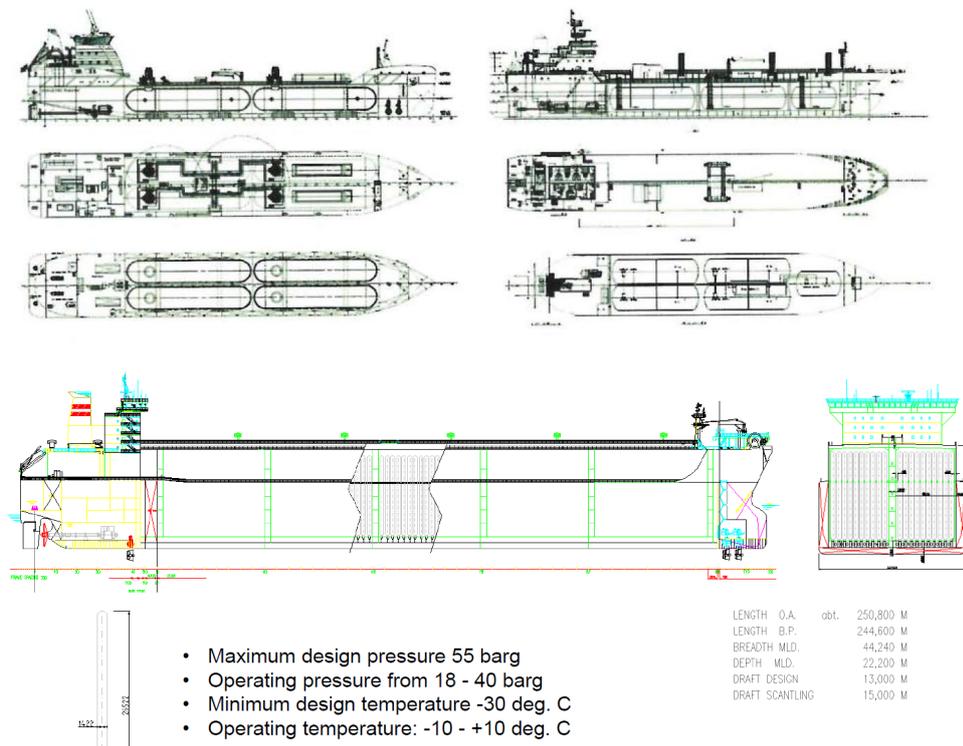


Figure 1. Top) Sketch of refrigerated CO<sub>2</sub> ship designs for Gassco Concept study [12]. Bottom) sketch of Knutsen Shipping's design of a pressurised CO<sub>2</sub> carrier (PCO<sub>2</sub>) [13].

For ship transport the logistics is important to consider as the cost of additional ships is significant. An optimisation exercise should be conducted where transport distance, ship size, unloading/loading time, cruising speed and number of ships are considered. An example of typical values applied to estimate cycle time is shown in Table 1.

Table 1. Example of estimating ship cycle time and number of cycles/year for 700 km (each way) CO<sub>2</sub> transport.

Activity	Duration	Comment
Time for ship loading and unloading	2 x 12 hours	If offshore direct injection to storage,
Time spent cruising:	2 x 700 km/(28 km/h) = 50 hours	28 km/h speed is used
Cycle time	74 hours	
Availability	90%	Impact of weather, repair, maintenance
Total cycles / year	106	

Table 2 provides an example on how much CO<sub>2</sub> that can be transported with one ship per year under the specified assumptions.

Table 2. Example on annually transported CO<sub>2</sub> amount by one ship. Assumptions Cycle time is 4 days (~700 km each way) and availability is 90%.

Ship capacity	2,000 tons	4,000 tons	10,000 tons
CO <sub>2</sub> transported annually	160.000 TPA	330.000 TPA	820.000 TPA

### CO<sub>2</sub> Liquefaction and terminal

To condition CO<sub>2</sub> for ship transport it will have to be liquefied. Liquefaction of CO<sub>2</sub> directly from a CO<sub>2</sub> capture plant (at low CO<sub>2</sub> feed pressure) is described in the Technology Catalogue on carbon capture.

Alternatively, if the CO<sub>2</sub> liquefaction plant is fed by dry high-pressure CO<sub>2</sub> from a pipeline the liquefaction process will be less complicated and consume significantly (approx. 1/3) less energy compared to directly from a capture plant. This can be relevant in the case CO<sub>2</sub> is transported in onshore pipeline to a CO<sub>2</sub> export terminal. In this case one can assume the liquefaction plant investment cost is only 0.2 M€/([ton CO<sub>2</sub>/h]) and power use is 50 kWh/ton CO<sub>2</sub>.

The CO<sub>2</sub> terminal will consist of well-insulated storage tanks for liquid CO<sub>2</sub>. The capacity can as a first estimate be selected as 100% of the ship's capacity. The storage tanks will as a minimum need to hold a volume equivalent to the amount of CO<sub>2</sub> recovered between each ship arrival (cycle time). The requirement of buffer e.g. for delays in ship arrival frequency, will normally be desirable. The buffer requirement will have to be evaluated from project to project.

In addition, a terminal will be equipped with transfer lines (liquid CO<sub>2</sub> and vapor return) and pumps that can load/unload the ship in typically around 10 hours will be present. Also, marine loading arms or flexible hoses to connect to the ship and other utilities are required. Vapour equalisation between onshore tank and ship tanks is required during ship loading/unloading. Because of heat ingress into the refrigerated liquid CO<sub>2</sub> storage there will be continuous evaporation of CO<sub>2</sub>. This needs to be re-liquefied at the terminal. In case the terminal is located together with the capture plant, the CO<sub>2</sub> vapours can be routed back to the main liquefaction plant and re-liquefied. If it is a satellite terminal it will need to be equipped with own refrigeration plant unless the ship arrival frequency is high.

### Input

Input to CO<sub>2</sub> ship transport is except for the liquid CO<sub>2</sub> cargo, fuel for propulsion. The fuel consumption is provided in units of MWh/day referring to energy content in the applied fuel (LHV, lower heating value). The fuel consumption applies only when the ship is operating at cruising speed and is an average of loaded and unloaded cruising. The energy consumption during unloading/loading at pier is significantly lower (around 10%) and may in some cases be covered by electric power from land. The consumption during unloading/loading is neglected here.

The fuel consumption applied in the datasheet for the 4,000 and 10,000 ton CO<sub>2</sub> ship of 90 and 180 kWh/day is based on input from Knutsen Shipping.

### Output

Output is liquid CO<sub>2</sub> cargo.

When a CO<sub>2</sub> tanker ship is loaded with CO<sub>2</sub> from an onshore storage tank, the CO<sub>2</sub> vapours in the ship's tank will be returned to the onshore storage tank. This will reduce the effective transport volume (or mass) of the ship. Because of the difference in vapour and liquid density this will only result in 3-4% reduction.

### Efficiency and losses

Significant energy consumption is involved with ship transport. IEA has estimated that 2.5% of the transported CO<sub>2</sub> is emitted from transporting CO<sub>2</sub> by ship for 200 km. For 12,000 km 18% CO<sub>2</sub> of transported CO<sub>2</sub> is released [4]. In a more recent study emissions from ship inclusive liquefaction (indirect emission from power generation) was reported to be unlikely to result in more than 2% of transported CO<sub>2</sub> volume [9]. Using the energy data of this catalogue a CO<sub>2</sub> emission of 0.4% of the transported volume is obtained for 200 km as shown in Table 2.

The CO<sub>2</sub> emission from ship transport will in addition to the transport distance depend on factors such as ship cruising speed and the type of fuel burned (HFO, MDO, LNG, etc.).

### Application potential

Ships will be applicable for point to point transport of CO<sub>2</sub> from CO<sub>2</sub> terminal at a capture plant location to offshore storage site (e.g. to an injection vessel) or another ship terminal e.g. at CO<sub>2</sub> utilisation site. A CO<sub>2</sub> ship may also operate in a route network where it collects CO<sub>2</sub> from several capture plant sites and deliver the CO<sub>2</sub> at a common destination.

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

### Typical capacities

The capacity range considered for ships in a CCS value chain are from 2,000 to 100,000 t CO<sub>2</sub> capacity. For as specific project the ship size is selected based on cost optimisation and redundancy requirements.

Only CO<sub>2</sub> carriers up to approx. 2000 t CO<sub>2</sub> is in operation today.

### Environmental and safety

The environmental impact of ship transport is mainly during the operation phase of the project. This is linked to the energy requirement and emissions from the ship.

#### Safety

Pressure tanks on ships are normally designed according to the international maritime organisation's (IMO) IGC code. The code specifies higher safety factors and margins compared to land-based pressure tanks. [12]

Because of the large volumes of CO<sub>2</sub> onboard ships or at land-based terminals, accidental release of large volumes of CO<sub>2</sub> (loss of containment scenario) is the main safety concern with ship transportation of CO<sub>2</sub>. If liquid CO<sub>2</sub> is depressurised to ambient pressure it will form a mixture of solid and gaseous

CO<sub>2</sub> (approx. 50/50) at -78°C. A large sustained release of liquid CO<sub>2</sub> will form a cold CO<sub>2</sub> gas cloud of high CO<sub>2</sub> concentration. The cloud will flow to low-points in terrain and gradually disperse in air depending on wind speed.

Sectionalisation of storage and transfer equipment, leak detection and ESD are means of risk mitigating. A risk assessment will have to be conducted for the CO<sub>2</sub> interim storage and loading operations to see if the location meets risk acceptance criteria.

### Research and development perspectives

If CO<sub>2</sub> transportation market will take off, there is a potential for development of new ship classes dedicated for CO<sub>2</sub> transport, which may reduce cost. In addition, development of new propulsion types and green shipping fuels may significantly decrease CO<sub>2</sub> emissions from ship transportation of CO<sub>2</sub>. If specialised CO<sub>2</sub> carriers are developed it is plausible that the energy consumption can be somewhat reduced due to a more optimised design.

The fixed O&M cost is to a large extent made up of personnel costs. Development of more autonomous ships may also reduce operating cost of ship transportation.

### Examples of market standard technology

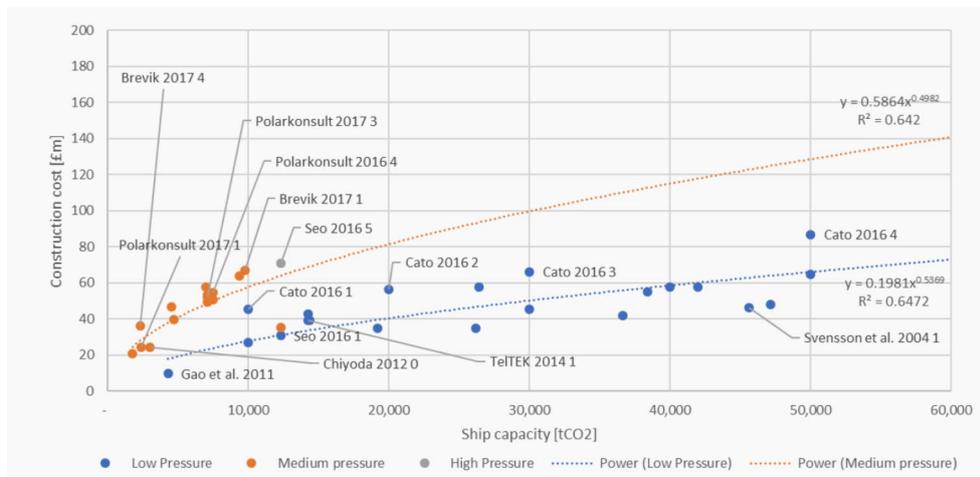
It is possible to use standard semi-refrigerated or fully pressurised gas carriers for transport of liquid CO<sub>2</sub>.

### Prediction of performance and costs

#### CAPEX

Several studies on the cost of ships for CO<sub>2</sub> transport have been reported in the literature. The energy consultancy company ElementEnergy have estimated CO<sub>2</sub> shipping cost for a UK scenario based on cost fitting to many of the available literature cost studies as shown in Figure 2. The figure distinguishes between low pressure CO<sub>2</sub> transport (6-8 bara), medium pressure (15-18 bara) and high pressure (40-50 bar). According to Figure 2, a ship equipped for the low-pressure CO<sub>2</sub> transport conditions is less than half of the cost of a ship for medium pressure. This is a remarkable cost gap which cannot be justified by cost differences between the pressure tanks alone. This may amongst others be related to poorer utilisation of ship's cargo volume as smaller pressure tanks will be used when design pressure is increased. As there is no data for the medium pressure alternative above about 12,000 t, the shown shape of the cost curve is uncertain for higher capacities. For the high-pressure conditions only a single data point is present, hence the CAPEX is highly uncertain for this alternative.

As the industrial standard today is based on CO<sub>2</sub> transport at medium pressure (15-18 bara) conditions the ship cost data for this alternative is selected for the data sheet.



**Figure 2. Investment cost for CO<sub>2</sub> carriers as a function of capacity from [9]. Low pressure 5-8 bar, Medium pressure: 15-20 bar.**

Different opinions in the literature exist on the advantage of refurbishing old gas carriers for CO<sub>2</sub> transport compared to newbuilt. According to Gassco study [12] refurbishment of old carriers may result in cost reduction of 60% or more compared to newbuilt vessel. On the other hand, ElementEnergy [9] argues that the investment cost of the ship will only constitutes 14% of the total transport cost of CO<sub>2</sub> (when liquefaction is included) hence CAPEX saving by refurbishing old vessels has low impact on the overall cost of CO<sub>2</sub> transport.

To obtain the full CAPEX of a full CO<sub>2</sub> ship transport chain, also CO<sub>2</sub> terminals for exporting and receiving the CO<sub>2</sub> with intermediate storage facilities must be included.

CO<sub>2</sub> export terminals of two capacities (4,000 and 14,000 ton CO<sub>2</sub>) have been estimated. Facilities included in the terminals include insulated bullet tanks, CO<sub>2</sub> transfer piping, marine loading arm, loading pumps, CO<sub>2</sub> metering equipment and utilities. The terminals are estimated for CO<sub>2</sub> at 15 bara and -27°C.

### OPEX

Main OPEX elements of ship transport are ship fuel cost and O&M cost for the ship. Fixed O&M is typically estimated as 5% of CAPEX per year for ships [9]. An uncertainty on OPEX is the harbour fee e.g. for landing a tonne of cargo, which may potentially be a substantial OPEX element. Harbour fee is not estimated here. Cost of CO<sub>2</sub> liquefaction is also substantial, but this is included at the CO<sub>2</sub> capture plant.

### Levelized cost of CO<sub>2</sub> ship transport

An example of the levelized cost of CO<sub>2</sub> transport by ship is shown in Table 3. The cost is estimated to 11.2 EUR/t CO<sub>2</sub> for transport of 560,000 tpa at a distance of 500 km with a vessel size of 4000 t CO<sub>2</sub>. Also included an onshore export terminal of 5000 t CO<sub>2</sub> capacity (25% buffer capacity).

**Table 3. Example of levelized cost of CO<sub>2</sub> ship transport. Ship size is 4000 t CO<sub>2</sub>. Export terminal of 5000 t CO<sub>2</sub> is included. CO<sub>2</sub> conditions 16 bara and -26°C, transport distance 500 km each way, loading/unloading time per cycle is 24 hours.**

Parameter	Cost	Comment
CAPEX 4000 t CO <sub>2</sub> ship	40 mill EUR	Unit cost of 10,000 EUR/t CO <sub>2</sub> from data sheet
CAPEX 5000 t CO <sub>2</sub> export terminal	12.5 mill EUR	Unit cost of 2500 EUR/t CO <sub>2</sub> from data sheet.
Annual. CAPEX (6%, 40 year)	3.5 mill EUR/year	40 years lifetime ship (only 25 years of terminal)
Fixed O&M	2.4 mill EUR /year	5% of CAPEX ship + 75 EUR/t CO <sub>2</sub> terminal capacity
Fuel cost	0.45 mil EUR/year	90 MWh/day from data sheet, 270 EUR/ton HFO,
Total annual cost	6.3 mil EUR/year	
Annual CO <sub>2</sub> transport	0.56 mill t CO <sub>2</sub> /year	8400 hrs and 140 cycles per year, 60 hour cycle time
Specific transport cost	<b>11.2 EUR/t CO<sub>2</sub></b>	Ex. harbour fee and taxes

The ZEP CO<sub>2</sub> transportation study [2] estimates cost of ship transport of CO<sub>2</sub> for 500 km distance at a yearly volume of 2.5 MTPA (smallest scenario) to 9.5 EUR/t CO<sub>2</sub>. This is relatively close to the estimate in Table 3-3. The ZEP estimate covers the low pressure transport conditions and larger vessels (30,000 t CO<sub>2</sub>) which leads to significantly lower CAPEX of the ship (Figure 3-2). On the other hand, the ZEP study applies higher value of capital (8%, 30 years).

### Uncertainty

As there is no commercial market for CO<sub>2</sub> transport by ship today the cost numbers are relatively uncertain. Most cost studies are based on LPG and other gas carriers, which are of relatively similar design and capacity.

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### Quantitative description

See separate Excel file for Data sheet

## 123 CO<sub>2</sub> transport by road

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Date	Ref.	Description
-	-	-

### Brief technology description

Transport of CO<sub>2</sub> on road tankers is widely applied today. For transport of large amounts of CO<sub>2</sub> it is transported in liquid form similar to ship transport conditions. The conditions used for road transport of liquid CO<sub>2</sub> is 15-18 bara and -25 to -30°C. Road transport of CO<sub>2</sub> is relevant of small to medium volumes of CO<sub>2</sub> e.g. from small point source emitters to CO<sub>2</sub> utilisation facilities or export terminals.

CO<sub>2</sub> trucks may be loaded from interim storage tanks. Normally dedicated loading bays with transfer equipment and gas return lines are present. A truck of 30 t CO<sub>2</sub> capacity can be loaded with Liquid CO<sub>2</sub> in around 45 min. It can be assumed that 45min unloading time at the destination.

### Input

Except from the liquid CO<sub>2</sub> cargo, input is fuel for the truck. In the data sheet the fuel cost has been included in the estimated km price for road transport of CO<sub>2</sub>. The energy demand (fuel use) applied in the cost calculation is stated in the data sheet.

### Output

Output of liquid CO<sub>2</sub> is same as input.

### Efficiency and losses

Significant energy consumption is involved with road transport of CO<sub>2</sub>. However, for short distances the emission is not that significant compared to the amount of CO<sub>2</sub> transported. As an example, transporting 30 t CO<sub>2</sub> 25 km will result in emission of less than 1% of the CO<sub>2</sub> for a round trip.

### Application potential

Road truck transport of CO<sub>2</sub> will mainly be relevant for small to medium volumes of CO<sub>2</sub> over limited distances. This may for instances by from a CO<sub>2</sub> capture plant at a relatively small emission source and to a nearby export terminal or CO<sub>2</sub> utilisation facility. Max CO<sub>2</sub> tanker truck capacity is around 25-30 t

CO<sub>2</sub> hence a large CO<sub>2</sub> point source e.g. 100 t CO<sub>2</sub>/h will imply many truckloads per hour around the clock which is often not desirable and more expensive than a pipeline.

### Typical capacities

The typical capacities of CO<sub>2</sub> road tankers are 25 to 30 ton. The annual transport capacity of a single truck will clearly decrease as the transport distance increases.

### Environmental and safety

The environmental impact of truck transport is mainly during the operation phase of the project. This is linked to high energy requirement and emissions from the truck.

#### Safety

CO<sub>2</sub> semi-trailers are accepted for road transport of CO<sub>2</sub> today. As the amount of CO<sub>2</sub> carried is relatively limited an accident involving leaking CO<sub>2</sub> will have relatively local effect. In congested areas such as in tunnels or in narrow streets dangerous levels of CO<sub>2</sub> is more likely to form in case of a large leakage.

### Examples of market standard technology

Semi-trailers with transport of liquid CO<sub>2</sub> at 15-18 bara and at -25 to -30°C is the standard technology for road transport.

### Prediction of performance and costs

Transport of CO<sub>2</sub> by truck is a standard service today, which is offered by several large transport companies. COWI has learned from commercial offers that road transport of CO<sub>2</sub> with diesel trucks with capacity of about 30 t CO<sub>2</sub> will cost around 6-8 EUR/t CO<sub>2</sub> for about 15 km and 13-18 EUR/ton CO<sub>2</sub> for 100 km distance. The cost includes loading and unloading to storage tanks and is based on transport of 400.000 tpa.

An estimate for CO<sub>2</sub> transportation cost by truck as function of capacity and distance has been derived where all cost elements (CAPEX and OPEX) have been lumped into a “fixed cost factor” (covering the time spent loading/unloading+ time share of CAPEX + O&M) as well as a variable cost factor (covering fuel consumption, time share of CAPEX + O&M, hours on road).

In the calculation of a cost factors for CO<sub>2</sub> road transport the following is assumed:

- CAPEX of semi-trailer truck with 30 t CO<sub>2</sub> load capacity (50 t gross weight) is estimated to 660,000 EUR.
- Annual maintenance is set to 4% of CAPEX and results in 1000 h unavailability per year
- Driver cost is 47 EUR/h (operation 24/7).
- Fuel consumption is 18 MJ/km (average of loaded and unloaded consumption) and fuel cost is 0.028 EUR/MJ.

- Loading and unloading time is set to 45 min each
- Average speed is 50 km/h.
- Truck CAPEX is annualized with 8% over 4 years.

With the above assumptions the cost of CO<sub>2</sub> transport is modelled at 3.8 EUR/t CO<sub>2</sub> + distance x 0.14 EUR/t CO<sub>2</sub>/km.

### Example of cost of CO<sub>2</sub> transport

In the table below the cost of truck transport of CO<sub>2</sub> is calculated for 15 and 100 km with the cost numbers given above. This is in good agreement with experienced commercial rates.

	15 km transport	100 km transport
Fixed cost	3.8 EUR/t CO <sub>2</sub>	3.8 EUR/t CO <sub>2</sub>
Variable cost	15 x 0.14 EUR/t CO <sub>2</sub>	100 x 0.14 EUR/t CO <sub>2</sub>
<b>Total cost</b>	<b>5.9 EUR/t CO<sub>2</sub></b>	<b>17.8 EUR/t CO<sub>2</sub></b>
CO <sub>2</sub> volume transported (24/7 operation)	110,000 tpa	42,000 tpa

## References

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### Quantitative description

See separate Excel file for Data sheet