Technology Data for Energy Plants for Electricity and District heating generation

August 2016

Update 2017 and March 2018

Danish Energy Agency

Amaliegade 44
DK-1256 Copenhagen K

P: +45 3392 6700
E: ens@ens.dk

www.ens.dk

Amendment sheet

Publication date

Publication date for this catalogue "Technology Data for Energy Plants" is august 2016. In June 2017 this amendment sheet has been added and also the possibility to add descriptions of amendments in the individual chapters if required. 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
March 18	99 Introduction, Biomass and Waste sections	Chapter added that gives a common introduction to the biomas and waste sheets (chapter 08, 09, 42 and 43)
March 18	08,09,42,43 Waste and Biomass CHP and boilers	Datasheet included, chapters will be included soon
March 18	11 Solid oxide fuel cell CHP (Natural gas/biogas)	Chapter added
March 18	12Low temperature proton exchange membrane fuel cell CHP (hydrogen)	Chapter added
January 18	05 Combined cycle gas turbine	Additional references have been included
January 18	06 Gas engines	Reference sheet have been updated
January 18	40 Heat pumps, DH and 44 gas fired DH boiler	Updated prices for auxiliary electricity consumption in data sheet
Novemb er 2017	01 Advanced Pulverized Fuel Power Plant	Datasheet for Advanced Pulverized Fuel Power Plant - Coal CHP included
October 2017	22 Photovoltaics	Datasheet for large ground mounted PV plants included
June 17	Preface	Small changes explaining the amendment sheet
June 17	21 Wind Turbines Offshore	Financial data (Investment cost and O&M) updated
June 17	41 Electric Boilers	Revised chapter added

Preface

The *Danish Energy Agency* and *Energinet*, the Danish transmission system operator, publish catalogues containing data on technologies for Energy Plants. This current catalogue includes updates of a number of technologies which replace the corresponding chapters in the previous catalogue published in May 2012 with updates published in October 2013, January 2014 and March 2015. The intention is that all technologies in the previous catalogue 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 in the energy system e.g. thermal gasification versus combustion of biomass or electricity storage in batteries versus fly wheels.

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.

Data sources and results

A guiding principle for developing the catalogue has been to rely primarily on well-documented and public information, secondarily on invited expert advice. Where unambiguous data could not be obtained, educated guesses or projections from experts are used. This is done to ensure consistency in estimates that would otherwise vary between users of the catalogue.

Cross-cutting comparisons between technologies will reveal inconsistencies which may have several causes:

- Technologies may be established under different conditions. As an example, the costs of off-shore wind farms might be established on the basis of data from ten projects. One of these might be an R&D project with floating turbines, some might be demonstration projects, and the cheapest may not include grid connections, etc. Such a situation will results in inconsistent cost estimates in cases where these differences might not be clear.
- Investors may have different views on economic attractiveness and different preferences. Some decisions may not be based on mere cost-benefit analyses, as some might tender for a good architect to design their building, while others will buy the cheapest building.

- Environmental regulations vary from between countries, and the environment-related parts of the investment costs, are often not reported separately.
- Expectations for the future economic trends, penetration of certain technologies, prices on energy and raw materials vary, which may cause differences in estimates.
- Reference documents are from different years. The ambition of the present publication has been to reduce the level of inconsistency to a minimum without compromising the fact that the real world is ambiguous. So, when different publications have presented different data, the publication which appears most in compliance with other publications has been selected as reference.

In order to handle the above mentioned uncertainties, each catalogue contains an introductory chapter, stating the guidelines for how data have been collected, estimated and presented. These guidelines are not perfect, but they represent the best balance between various considerations of data quality, availability and usability.

Danish preface

Energistyrelsen og Energinet udarbejder teknologibeskrivelser for en række el- og varmeproduktionsteknologier. Dette nuværende katalog indeholder opdateringer af en stor del af teknologibeskrivelserne, som erstatter de tilsvarende kapitler i det gamle katalog, som blev udgivet i 2012 og senere opdateret i 2013, 2014 og 2015. Det er hensigten, at alle teknologibeskrivelserne fra det gamle katalog skal opdateres og integreres her. Desuden vil kataloget løbende opdateres i takt med at teknologierne udvikler sig, hvis data ændrer sig væsentligt eller hvis der findes fejl. Alle opdateringer vil registreres i rettelsesbladet først i kataloget, og det vil altid være muligt at finde den seneste opdaterede version på Energistyrelsens hjemmeside.

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

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

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

Tabel of Contents

Introduction

This catalogue covers data regarding energy plants for generation of electricity and district heating. Three distinct categories of plants are included:

- **Heat-only generation**: technologies producing only heat to be provided to the district heating network (e.g. boilers and heat pumps);
- **Thermal electricity generation**: plants producing electricity with thermal processes (for example steam cycle or internal combustion engines), including combined heat and power plants (CHP).
- **Non-thermal electricity generation**: technologies producing electricity without thermal processes, such as wind power, solar power or hydroelectric power plants.

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 the section below. 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 assumptions

The boundary for both cost and performance data is the generation assets plus the infrastructure required to deliver the energy to the main grid. For electricity, this is the nearest land-based substation of the transmission/distribution grid, while district heat is delivered to the nearest district heating network. In other words, the technologies are described as they are perceived by the electricity or district heating systems receiving their energy deliveries. Thus, stated capacities are net capacities, which are calculated as the gross generation capacity minus the auxiliary power consumption “capacity” at the plant. Similarly, efficiencies are also net efficiencies.

Unless otherwise stated, the thermal technologies in the catalogue are assumed to be designed and operated for approx. 4000-5000 full load hours annually. 75 % of generation is expected to take place in full load and the remaining 25 % in part load. Some of the exceptions are municipal solid waste incineration facilities and stand-alone biogas plants, which are designed for continuous operation, i.e. approximately 8000 full load hours annually. The assumed numbers of full load hours are summarized in table 1.

For electricity and heat production technologies dependent on wind and solar resources, estimates of annual full load hours of production are made for each technology.

	Full load hours (electricity)	**Full load hours** (heat)
CHP back pressure units	4000	4000
CHP extraction units	5000	4000
Municipal solid waste / biogas stand alone	8000	8000
Boilers and heat pumps		4000
Geothermal heat		6000
Electric boilers		500

Table 1: Assumed number of full load hours.

1.2. Qualitative description

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

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 raw materials and primarily fuels, consumed by the technology.

Output

The forms of generated energy, i.e. electricity and heat, and any relevant by-products.

Typical capacities

The stated capacities are for a single unit capable of producing energy (e.g. a single wind turbine or a single gas turbine), not a power plant consisting of a multitude of unit such as a wind farm.

In the case of a modular technology such as PV or solar heating, a typical size of a solar power plant based on the market standard is chosen as a unit. Different sizes may be specified in separated tables, e.g. Small PV, Medium PV, Large PV.

Space requirement

Space requirement is expressed in 1000 m^2 per MW. The value presented only refers to the area occupied by the facilities needed to produce energy.

In case the area refers to the overall land use necessary to install a certain capacity, or a certain minimum distance from dwellings is required, for instance in case of a wind farm, this is specified in the notes. 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 plant.

Regulation ability and other power system services

Regulation abilities are particularly relevant for electricity generating technologies. This includes the part-load characteristics, start-up time and how quickly it is able to change its production when already online.

If relevant, the qualitative description includes the technology's capability for delivering the following power system services:

- Inertia
- Short circuit power
- Black start
- Voltage control
- Damping of system oscillations (PSS)

Advantages/disadvantages

A description of specific advantages and disadvantages relative to equivalent technologies. Generic advantages are ignored; e.g. renewable energy technologies mitigating climate risks and enhance security of supply.

Environment

Particular environmental characteristics are mentioned, for example special emissions or the main ecological footprints.

The energy payback time or energy self-depreciation time may also be mentioned. This is the time required by the technology for the production of energy equal to the amount of energy that was consumed during the production and the installation of the equipment.

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. 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*" [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_2-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" [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.

<u>Category 1</u>. 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).

<u>Category 2</u>. 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).

<u>Category 3</u>. *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)

<u>Category 4</u>. *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)

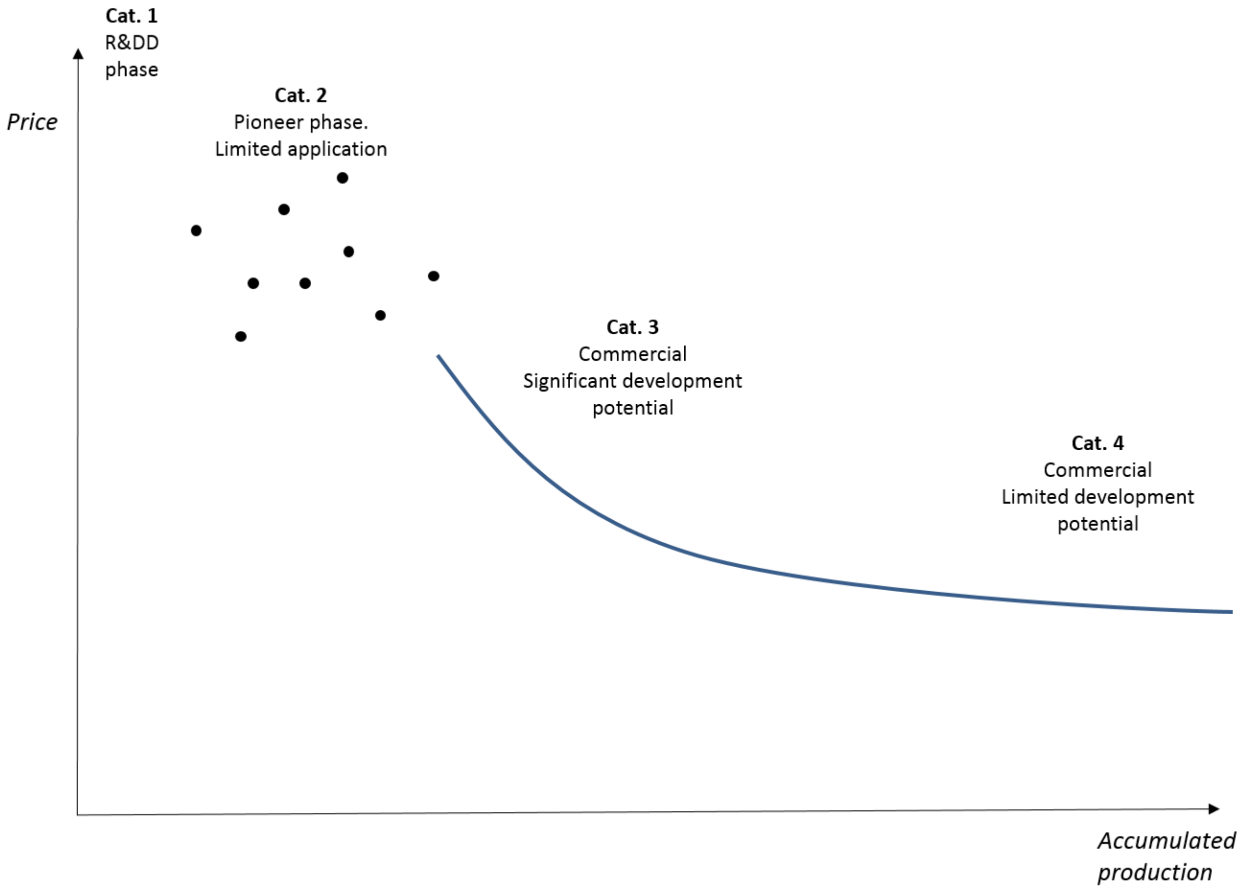


Figure 1: Technological development phases. Correlation between accumulated production volume (MW) and price.

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 long time 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 table consists of a generic part, which is identical for groups of similar technologies (thermal power plants, non-thermal power plants and heat generation 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 efficiencies. Other figures are considered if relevant.

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 generic parts of the tables for thermal power plants, non-thermal power plants and heat generation technologies are presented below:

Technology	**Thermal elec. generation CHP or ELEC only**									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)										
Electricity efficiency (condensation mode for extraction plants), net (%), name plate										
Electricity efficiency (condensation mode for extraction plants), net (%), annual average										
Cb coefficient (50°C/100°C)										
Cv coefficient (50°C/100°C)										
Forced outage (%)										
Planned outage (weeks per year)										
Technical lifetime (years)										
Construction time (years)										
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Minimum load (% of full load)										
Warm start-up time (hours)										
Cold start-up time (hours)										
Environment										
SO_2 (degree of desulphuring, %)										
NO_X (g per GJ fuel)										
CH4 (g per GJ fuel)										
N2O (g per GJ fuel)										
Financial data										
Specific investment (M€/MW)										
- of which equipment										
- of which installation										
Fixed O&M (€/MW/year)										
Variable O&M (€/MWh)										
Startup cost (€/MW/startup)										

Technology	Non-thermal electricity generation									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)										
Average annual full-load hours										
Forced outage (%)										
Planned outage (weeks per year)										
Technical lifetime (years)										
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Financial data										
Specific investment (M€/MW)										
- of which equipment										
- of which installation										
Fixed O&M (€/MW/year)										
Variable O&M (€/MWh)										

Technology	Heat only generation tech (boilers, heat pumps, geothermal)									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Heat generation capacity for one unit (MW)										
Total efficiency, net (%), name plate										
Total efficiency , net (%), annual average										
Auxiliary electricity consumption (% of heat gen)										
Forced outage (%)										
Planned outage (weeks per year)										
Technical lifetime (years)										
Construction time (years)										
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Minimum load (% of full load)										
Warm start-up time (hours)										
Cold start-up time (hours)										
Environment										
SO_2 (g per GJ fuel)										
NO_X (g per GJ fuel)										
CH4 (g per GJ fuel)										
N2O (g per GJ fuel)										
Financial data										
Specific investment (M€ per MW)										
- of which equipment										
- of which installation										
Fixed O&M (€/MW/year)										
Variable O&M (€/MWh)										
Startup cost (€/MW/startup)										

Energy/technical data

Generating capacity for one unit

The capacity, preferably a typical capacity (not maximum capacity), is stated for a single unit, capable of producing energy e.g. a single wind turbine (not a wind farm), or a single gas turbine (not a power plant consisting of multiple gas turbines).

In the case of a modular technology such PV or solar heating, a typical size of a solar power plant based on the historical installations or the market standard is chosen as a unit. Different sizes may be specified in separated tables, e.g. Small PV, Medium PV, Large PV.

The capacity is given as net generation capacity in continuous operation, i.e. gross capacity (output from generator) minus own consumption (house load), equal to capacity delivered to the grid. For heat only technologies, any auxiliary electricity consumption for pumps etc. is not counted in the capacity. For combined heat and power generation, only the electric capacity is stated. For extraction plants, the capacity is stated in condensation mode.

The unit MW is used both for electric generation capacity and heat production capacity. While this is not in accordance with thermodynamic formalism, it makes comparisons easier and provides a more intuitive link between capacities, production and full load hours.

The relevant range of sizes of each type of technology is represented by a range of capacities stated in the notes for the “capacity” field in each technology table, for example 200-1000 MW for a new coal-fired power plant.

It should be stressed that data in the table is based on the typical capacity, for example 600 MW for a coal-fired power plant. When deviations from the typical capacity are made, economy of scale effects need to be considered inside the range of typical sizes (see the section about investment cost). The capacity range should be stated in the notes.

Energy efficiencies

Efficiencies for all thermal plants (both electric, heat and combined heat and power) are expressed in percent at lower calorific heat value (lower heating value) at ambient conditions in Denmark, considering an average air temperature of approximately 8 °C.

The electric efficiency of thermal power plants equals the total delivery of electricity to the grid divided by the fuel consumption. Two efficiencies are stated: the nameplate efficiency as stated by the supplier and the expected typical annual efficiency. Total efficiency of thermal power plants can be calculated as described in the formulas of the Annex in the previous catalogue for energy plants available from the Danish Energy Agency’s web site.

For extraction plants, the electric efficiency is stated in condensation mode.

For heat only technologies, the total efficiency equals the heat delivered to the district heating grid divided by the fuel consumption. The auxiliary electricity consumption is not included in the efficiency, but stated separately in percentage of heat generation capacity (i.e. MW auxiliary/MW heat).

The energy supplied by the heat source for heat pumps (both electric and absorption) is not counted as input energy. The temperatures of the heat source are specified in the specific technology chapters.

The expected typical annual efficiency takes into account a typical number of start-ups and shut-downs and is based on the assumed full load hours stated in the introduction (table 1). Regarding the assumed number of start-ups for different technologies, an indication is given in the financial data description, under start-up costs.

Often, the electrical efficiency decreases slightly during the operating life of a thermal power plant. This degradation is not reflected in the stated data. As a rule of thumb 2.5 – 3.5 % may be subtracted during the lifetime (e.g. from 40 % to 37 %). Specific data are given in [3].

Some combined heat and power plants and heat producing boilers are equipped with flue gas condensation equipment, a process whereby the flue gas is cooled below its water dew point and the heat released by the resulting condensation of water is recovered as low temperature heat. In these cases, the stated efficiencies include the added efficiency of the flue gas condensation equipment.

If a combined heat and power plant is equipped with a turbine bypass enabling the plant to produce only heat – for example during periods with low electricity prices – this is mentioned in a note. Per default, it is assumed that the heat efficiency equals the plant's total efficiency when the turbine bypass is applied. Moreover, it is assumed that in by-pass mode the heat capacity corresponds to the sum of the heat and electrical capacities in back-pressure mode.

In a Danish context, seawater is normally used for cooling/condensation, when there is a surplus of heat generation from a CHP plant. Therefore, cooling towers are not considered, for the CHP plant in this catalogue.

The energy efficiency for intermittent technologies (e.g. PV and wind) is expressed as capacity factor. The capacity factor is calculated as the annual production divided by the maximum potential annual production. The maximum potential annual production is calculated assuming the plant has been operating at full load for the entire year, i.e. 8760 hours /year.

Auxiliary electricity consumption

For heat-only technologies the consumption of electricity for auxiliary equipment such as pumps, ventilation systems, etc. is stated separately in percentage of heat generation capacity (i.e. MW auxiliary/MW heat).

For heat pumps, internal consumption is considered part of the efficiency (coefficient of performance, COP), while other electricity demand for external pumping, e.g. ground water pumping, is stated under auxiliary electricity consumption.

For CHP generation, auxiliary consumption is not stated separately but included in the net efficiency and for non-thermal plants, as a reduction in the number of full load hours.

Cogeneration values

The C_b-coefficient (backpressure coefficient) is defined as the maximum power generation capacity in backpressure mode divided by the maximum heat production capacity (including flue gas condensation if applicable).

The C_v-value for an extraction steam turbine is defined as the loss of electricity production, when the heat production is increased one unit at constant fuel input.

Values for C_b and C_v are given – unless otherwise stated – at 100 °C forward temperature and 50 °C return temperature, corresponding to heat delivered to district heating transmission systems. For technologies where delivery to district heating distribution systems are more relevant a temperature set of 80/40 °C may also be used, and this is stated in the data sheet.

Average annual full load hours

The average annual capacity factor mentioned above describes the average annual net generation divided by the theoretical maximum annual net generation if the plant were operating at full capacity for 8760 hours per year. The equivalent full load hours per year is determined by multiplying the capacity factor by 8760 hours, the total number of hours in a year.

The full load hours for non-thermal technologies represent the expected production considering planned and forced outage and auxiliary consumption, if any.

Full load hours vary largely depending on the location and the technology choice. The value stated refers to the Danish context, in an average location and with market standard technology.

Forced and planned outage

Forced outage is defined as the number of weighted forced outage hours divided by the sum of forced outage hours and operation hours. The weighted forced outage hours are the sum of hours of reduced production caused by unplanned outages, weighted according to how much capacity was out.

Forced outage is given in percent, while planned outage (for example due to renovations) is given in days per year.

Technical lifetime

The technical lifetime is the expected time for which an energy plant 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, power plant efficiencies often decrease slightly (few percent) 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 plant is decommissioned or undergoes a lifetime extension, which implies a major renovation of components and systems as required to make the plant 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. As stated earlier, the thermal technologies producing electricity and/or heat are in general assumed to be designed for operated for approximately 4,000-5,000 full loads hours annually. The expected technical lifetime takes into account a typical number of start-ups and shut-downs (an indication of the number of start-ups and shut-downs is given in the Financial data description, under Start-up costs).

In real life, specific plants of similar technology may operate for shorter or longer times. The strategy for operation and maintenance, e.g. the number of operation hours, start-ups, and the reinvestments made over the years, will largely influence the actual lifetime.

Construction time

Time from final investment decision (FID) until commissioning completed (start of commercial operation), expressed in years.

Regulation ability

Five parameters describe the electricity regulation capability of the technologies:

A. Primary regulation (% per 30 seconds): frequency control
B. Secondary regulation (% per minute): balancing power
C. Minimum load (percent of full load).
D. Warm start-up time, (hours)
E. Cold start-up time, (hours)

For several technologies, these parameters are not relevant, e.g. if the technology is regulated instantly in on/off-mode.

Parameters A and B are spinning reserves; i.e. the ability to regulate when the technology is already in operation.

Parameter D. The warm start-up time used for boiler technologies is defined as the time it takes to reach operating temperatures and pressure and start production from a state where the water temperature in the evaporator is above 100^{o}C, which means that the boiler is pressurized.

Parameter E. The cold start-up time used for boiler technologies is defined as the time it takes to reach operating temperature and pressure and start production from a state were the boiler is at ambient temperature and pressure.

Environment

All plants are assumed to be designed to comply with the regulation that is currently in place in Denmark and planned to be implemented within the 2020 time horizon.

The emissions below are stated in mass per GJ of fuel at the lower heating value.

CO_2 emission values are not stated, as these depend only on the fuel, not the technology.

SO_x emissions are calculated based on the following sulfur contents of fuels:

	Coal	Ori-mulsion	Fuel oil	Gas oil	Natural gas	Peat	Straw	Wood-fuel	Waste	Biogas
Sulphur, kg/GJ	0.27	0.99	0.25	0.07	0.00	0.24	0.20	0.00	0.27	0.00

For technologies, where desulphurization equipment is employed (typically large power plants), the degree of desulphurization is stated in percent.

NO_x . NO_x equals NO_2 + NO, where NO is converted to NO_2 in weight-equivalents.

Greenhouse gas emissions include CH_4 and N_2O in grams per GJ fuel.

Particles includes the fine particle matters (PM 2.5). The value is given in grams per GJ of fuel.

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 ratio of 7.45 DKK per € has been used.

The previous catalogue was in 2011 prices. Some data have been updated by applying the general inflation rate in Denmark (2011 prices have been multiplied by 1.0585 to reach the 2015 price level).

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 has been found to be impossible above the regional or local levels, as per IEA reporting from 2015 [4]. 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. Infrastructure and connection costs, i.e. electricity, fuel and water connections inside the premises of a plant, are also included.

The investment cost is reported on a normalized basis, i.e. cost per MW. The specific investment cost is the total investment cost divided by the capacity stated in the table, i.e. the capacity as seen from the grid, whether electricity or district heat. For electricity generating technologies, incl. combined heat and power generation, the denominator is the electric capacity.

The investment cost of extraction steam turbines, which can be operated in condensation mode, is stated as cost per MW-condensation mode capacity.

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, grid connection, 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 plants are also not included. Decommissioning costs may be offset by the residual value of the assets.

Cost of grid expansion

The costs of grid expansion from adding a new electricity generator or a new large consumer (e.g. an electric boiler or heat pump) to the grid are not included in the presented data.

The most important costs are related to strengthening or expansion of the local grid and/or substations (voltage transformation, pumping or compression/expansion). The costs vary significantly depending on the type and size of generator and local conditions. For planning purposes, a generic cost of 0.14 M€2015 may be added to the stated investment costs per MW the grid needs be strengthened. This is due for a single expansion. If more generators (or consumers) are connected at the same time, the aggregated capacity addition may be smaller than the sum of the individual expansions, since peak-loads do not occur simultaneously.

Business cycles

The cost of energy equipment shows fluctuations that can be related to business cycles. This was the case of the period 2007-2008 for example, where costs of many energy generation technologies surged dramatically. The trend was general and global. An example is combined cycle gas turbines (CCGT), for which prices increased sharply from $400-600 per kW to peaks of $1250. When projecting the costs of technologies, it is attempted to compensate, as far as possible, for the effect of any business cycles, that may influence the current prices.

Economy of scale

The main idea of the catalogue is to provide technical and economic figures for particular sizes of plants. Where plant sizes vary in a large range, different sizes are defined and separate technology chapters are developed.

For assessment of data for plant sizes not included in the catalogue, some general rules should be applied with caution to the scaling of plants.

The cost of one unit for larger power plants is usually less than that for smaller plants. This is called the 'economy of scale'. The basic equation [2] is:

$$\frac{C_1}{C_2} = \left(\frac{P_1}{P_2}\right)^a$$

Where: C_1 = Investment cost of plant 1 (e.g. in million EUR)

C_2 = Investment cost of plant 2

P_1 = Power generation capacity of plant 1 (e.g. in MW)

P_2 = Power generation capacity of plant 2

a = Proportionality factor

Usually, the proportionality factor is about 0.6 – 0.7, but extended project schedules may cause the factor to increase. It is important, however, that the plants are essentially identical in construction technique, design, and construction time frame and that the only significant difference is in size.

The relevant ranges where the economy of scale correction applies are stated in the notes for the capacity field of each technology table. The stated range represents typical capacity ranges.

Large-scale plants, such as coal and nuclear power plants, seems to have reached a size limit, as few investors are willing to add increments of 1000 MW or above. Instead of the scaling effect, multiple unit configurations may provide savings by allowing sharing of balance of plant equipment and support infrastructure. Typically, about 15 % savings in investment cost per MW can be achieved for combined cycle gas turbines and big steam power plants from a twin unit arrangement versus a single unit [3].

Operation and maintenance (O&M) costs

The fixed share of O&M is calculated as cost per generating capacity per year (€/MW/year), where the generating capacity is the one defined at the beginning of this chapter and stated in the tables. It includes all costs, which are independent of how many hours the plant is operated, e.g. administration, operational staff, payments for O&M service agreements, network or system charges, property tax, and insurance. Any necessary reinvestments to keep the plant 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 of the plants may be mentioned in a note if data are available.

The variable O&M costs (€/MWh) include consumption of auxiliary materials (water, lubricants, fuel additives), treatment and disposal of residuals, spare parts and output related repair and maintenance (however not costs covered by guarantees and insurances).

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.

Fuel costs are not included.

Auxiliary electricity consumption is included for heat only 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 noticed that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Start-up costs

The O&M costs stated in this catalogue includes start-up costs and takes into account a typical number of start-ups and shut-downs. Therefore, the start-up costs should not be specifically included in more general analyses. They should only be used in detailed dynamic analyses of the hour-by-hour load of the technology.

Start-up costs, are stated in costs per MW of generating capacity per start up (€/MW/startup), if relevant. They reflect the direct and indirect costs during a start-up and the subsequent shut down.

The direct start-up costs include fuel consumption, e.g. fuel which is required for heating up boilers and which does not yield usable energy, electricity consumption, and variable O&M costs corresponding to full load during the start-up period.

The indirect costs include the theoretical value loss corresponding to the lifetime reduction for one start up. For instance, during the heating-up, thermal and pressure variations will cause fatigue damage to components, and corrosion may increase in some areas due to e.g. condensation.

An assumption regarding the typical amount of start-ups is made for each technology in order to calculate the O&M costs. This assumption is specified in the notes. The following table shows the assumed number of start-ups per year included in the O&M costs for some technologies.

	Assumed number of start-ups per year
Coal CHP	15
Natural gas CHP (except gas engines)	30
Gas Engines	100
Wood pellet CHP	15
Heat only boilers	50
Municipal solid-waste / biogas stand alone	5
Geothermal heat	5
Heat pumps	30
Electric boilers	100

The stated O&M costs may be corrected to represent a different number of start-ups than the one presented in the table by using the stated start-up costs with the following formula:

$$O\&M_{new} = O\&M_{old} - \left(Startup\ cost * n_{startup}^{old}\right) + \left(Startup\ cost * n_{startup}^{new}\right)$$

where $n_{startup}^{old}$ is the number of start-ups specified in the notes for the specific technology and $n_{startup}^{new}$ is the desired number of start-ups.

Technology specific data

Additional data is specified in this section, depending on the technology.

Definitions

The steam process in a CHP (co-generation of heat and power) plant can be of different types:

1. **Condensation**: All steam flows all the way through the steam turbine and is fed into a condenser, which is cooled by water at ambient temperature. A condensing steam turbine produces only electricity, no heat.
2. **Back-pressure**: All steam flows all the way through the steam turbine and is fed into a condenser, which is cooled by the return stream from a district heating network or an industrial process heating network. The condensation takes place at elevated temperatures enabling utilization of the produced heat. A back-pressure turbine produces electricity and heat, at an almost constant ratio.
3. **Extraction**: Works in the same way as condensation, but steam can be extracted from the turbine to produce heat (equivalent to back-pressure). This enables flexible operation where the electricity to heat ratio may be varied.

References

Numerous reference documents are mentioned in each of the technology chapters. The references mentioned below are for Chapter 1 only.

[1] Forudsætninger for samfundsøkonomiske analyser på energiområdet (Generic data to be used for socio-economic analyses in the energy sector), Danish Energy Agency, May 2009.

[2] Economy of Scale in Power Plants, August 1977 issue of Power Engineering Magazine.

[3] Projected Costs of Generating Electricity, International Energy Agency, 2010.

[4] Projected Costs of Generating Electricity, International Energy Agency, 2015.

[5] Konvergensprogram Danmark 2015, Social- og Indenrigsministeriet, March 2015.

[6] Energy Technology Perspectives, International Energy Agency, 2012.

[7] International Energy Agency. Available at: http://www.iea.org/. Accessed: 11/03/2016.

01 Advanced Pulverized Fuel Power Plant (for qualitative description go to previous catalogue)

This chapter is under review.

Until then the qualitative description and the datasheet for large CHP combusting wood pellets and natural gas please look at the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

The datasheet for large coal fired "Advanced Pulverized Fuel Power Plant" has been updated in 2017 and can be found here below. A note (in Danish) documenting the updating can be found at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Author: Ea Energy Analyses

Publication date

November 2017

Amendments after publication date

Date	Ref.	Description
November 2017	01 Advanced Pulverized Fuel Power Plant	Datasheet for Advanced Pulverized Fuel Power Plant - Coal CHP included

01 Advanced Pulverized Fuel Power Plant - Coal CHP

Technology	Steam turbine, pulverized coal fired, advanced steam process					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	400 - 700					
Electricity efficiency, condensation mode, net (%)	44-48	46-51	52	52-55	C	8;7;9;11
Cb coefficient (50°C/100°C)	0.75	0.84	1.01		A	
Cv coefficient (50°C/100°C)	0.15	0.15	0.15			1
Availability (%)	95	95	95		E	7
Technical lifetime (years)	40	40	40	40	F	6
Construction time (years)	4.5	4.5	4.5			2;3;3
Environment						
SO_2 (degree of desulphuring, %)	97	97	97	97	B	5
NO_X (g per GJ fuel)	38	35	35	35	B	12;5;5;5
CH4 (g per GJ fuel)	1.5	1.5	1.5	1.5		13;5;5;5
N2O (g per GJ fuel)	0.8	0.8	0.8	0.8		13;5;5;5
Financial data						
Nominal investment (M€/MW)	1.93	1.9	1.86	1.78	J	17,18,19,20,21,22
Fixed O&M (€/MW/year)	31,500	31,000	30,355	29,105	J	17,18,19,20,21,22
Variable O&M (€/MWh)	3.0	2.9	2.8	2.7	J	17,18,19,20.21,22
Regulation ability						
Primary load support (% per 30 seconds)	5	5	5	5	D	14
Secondary load support (% per minute)	4	4	4	4	D	14
Minimum load (% of full load)	18	15	15	10		10+14

References:

1 Elsam, November 2003
2 Elsam's and Elkraft's update of the Danish Energy Agency's 'Teknologidata for el- og varmeproduktionsanlæg', December 1997
3 Eltra, September 2003
5 Danish Energy Agency, 2009.
6 "Projected costs of generating electricity", International Energy Agency (IEA), 2005.
7 "Energy technology perspectives 2008", International Energy Agency, 2008.
8 Danish Energy Agency, 2008. Measured data (1994-2006) from newest power plants in Denmark.
9 Own estimate by Danish Energy Agency and Energinet.dk, 2011.
10 Energinet.dk, 2009

11 www.ad700.dk

12 "En opdateret analyse af Danmarks muligheder for at reducere emissionerne af NOx" (Updated analysis of Denmark's options to reduce NOx emissions; in Danish), Danish Environmental Protection Agency, 2009.

13 National Environmental Research Institute, Denmark, 2009 (data from 2007).

14 DONG Energy, 2009.

15 "UK Electricity Generation Costs Update", Mott MacDonald, June 2010.

16 "The Costs of CO2 Capture, Transport and Storage", Zero Emissions Platform (ZEP), July 2011

17 The IEA World Energy Outlook 2014 coal fired Ultra-supercritical power plants in Europe. Values used are the projection for 2020.

18 The IEA Projected Cost of Generating Electricity 2015 for coal fired power plants. Here both the 'world median' is used, and data from recently commissioned plants in the Netherlands. The three units in the Netherlands are chosen because of the proximity to Denmark, because the socio-economic parameters (labour cost etc) are assumed to be similar and because the units are new (all from 2015).

19 EIA Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants 2013 for pulverizes coal fired advanced single units.[1]

20 Aggregated data from different projects on existing units that Ea Energy Analyses have been working on since 2010. Data is used for estimating O&M costs.

21 IEA(2016),Energy Technology Perspectives

22 E.S. Rubin et al. / Energy Policy 86 (2015) page 198–218, A review of learning rates for electricity supply technologies

Notes:

A The Cb values have been calculated from the electricity efficiencies in condensation mode, the Cv values and a total efficiency (electricity plus heat) in full back-pressure mode of 90%. Cf. Annex 1.

B The data for SO2 and NOx emissions assume flue gas desulphurisation (wet gypsum) and DeNOx equipment of the "high dust" SCR type.

C Supercritical in 2010 and ultra-supercritical from 2020.

D Please refer to section 'Regulation ability' in the above qualitative description.

E Outage rates are generally about 5% for plants that are 10-20 years old. Unless the plant is refurbished, the rate increases to 20% for plants that are 40 years old (ref. 7)

F The lifespan is often quite long (up to 60 years). For this to happen, refurbishment is required (ref. 7).

J It is assumed that the cost is falling by 0.2 % p.a.

Defaltor 2011-2015	1.059

02 Life Time Extensions of Coal Power Plants

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Author: Ea Energy Analyses

Publication date

August 2016

Amendments after publication date

Date	Ref.	Description

Qualitative description

Brief technology description

Large coal power plants have been a major source of combined electricity and heat generation in Denmark for the last decades. When a plant has been in operation for 25 years or more, the reliability of its components and systems will likely decrease leading to reduced availability and/or increased O&M costs. Therefore, based on experience, it will usually be necessary and beneficial to carry out a larger package of work that addresses repairs, renovation, and replacement of selected components and systems depending on their actual condition. Often also, improvement of environmental performance may be required, e.g. by improving the flue gas cleaning performance. This 'Life Time Extension' (LTE) is done with the purpose of restoring the plant to come close to its original conditions in terms of availability, efficiency and O&M costs. The exact scope and extent of such a campaign though, shall be tailored to the actual plant in question and will depend on its design, previous records of operation, earlier major works carried out, etc. Also, the expected/desired future operation of the plant is taken into account. Whether or not to extend the life of a power plant is therefore not a simple decision, but involves complex economic and technical factors [1].

In this technology catalogue it is assumed that the life time extension

- takes place after approx. 25 years of normal operation, during which
- the maintenance of the plant has been carried out as planned, and
- enables the plant to be operated with the availability rate close to that of the original new plant
- within the originally expected O&M budget,
- for an extended life time of approx. 15-20 years

It may be convenient to carry out all necessary works in one campaign, to reduce the overall down time, or to distribute the work over several years. For this case it is assumed that all work is done in one campaign. It is expected that the original plant comply with the environmental legislation at the time of the LTE. The costs of bringing it up to date prior to the LTE are therefore not taken into account.

The LTE described here does not take specific measures to increase the efficiency, emissions level standards, or regulation abilities of the plant. Such required or desirable improvements may follow as a consequence without further investments, or may be possible at a reduced investment when major overhauls and component replacements are carried out anyhow.

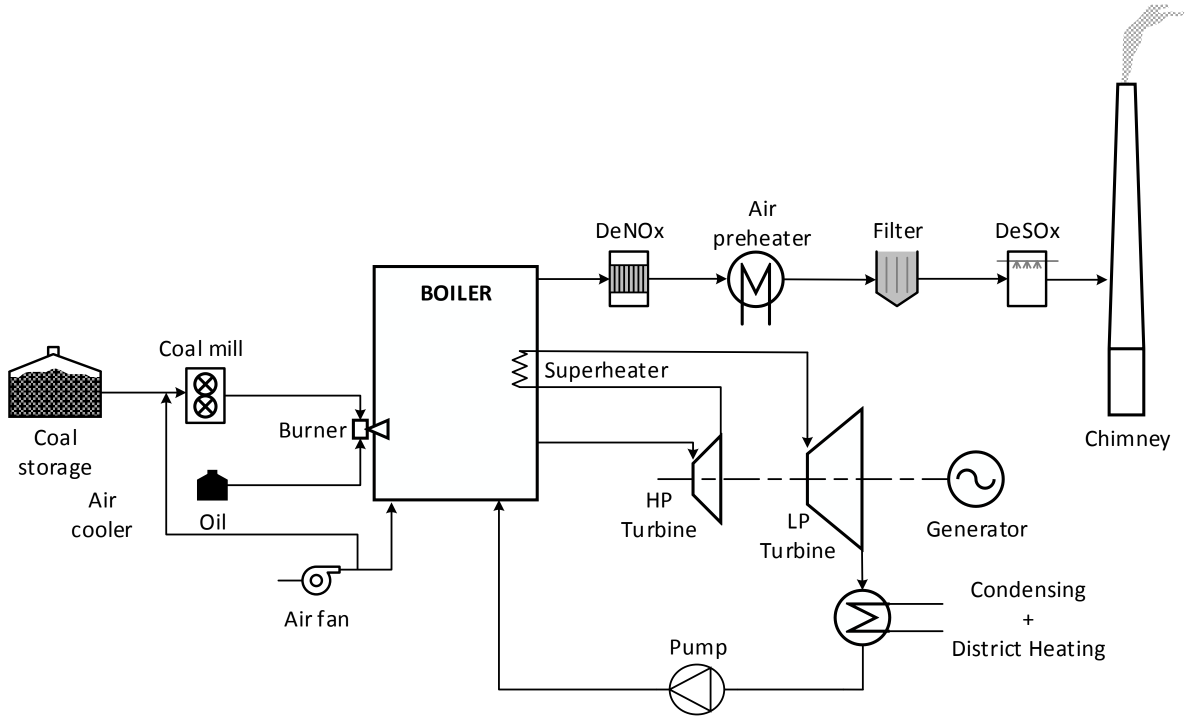


Figure 1: Sketch of the main elements of a large coal fired CHP plant.

In connection with the LTE the plant will be out of operation for a period, typically 6-9 months.

The LTE will typically involve considerable project costs for planning and management since it requires establishing a project organisation for engineering, purchase, construction management, test, and commissioning.

The distribution of works and costs involved with a LTE of and existing coal fired plant could typically be as follows, however depending widely on the actual scope [1]

Main elements can be:

- Revision of electrical systems
- Instrumentation and control systems replacement
- Pulverizers upgrade or replacement (fuel supply and disposal)
- Boiler upgrade,
- Turbine refurbishment (possibly generator refurbishment)
- Water systems (heat exchanges for condensers and district heating)

- Buildings
- Flue gas cleaning.

At top of that, there is a relatively large share of project- and unexpected costs (see figure 2). The basis for deciding which works to include in the LTE is an understanding of the plant's condition, which can be obtained using diagnostic systems and making a detailed remaining life assessment [2].

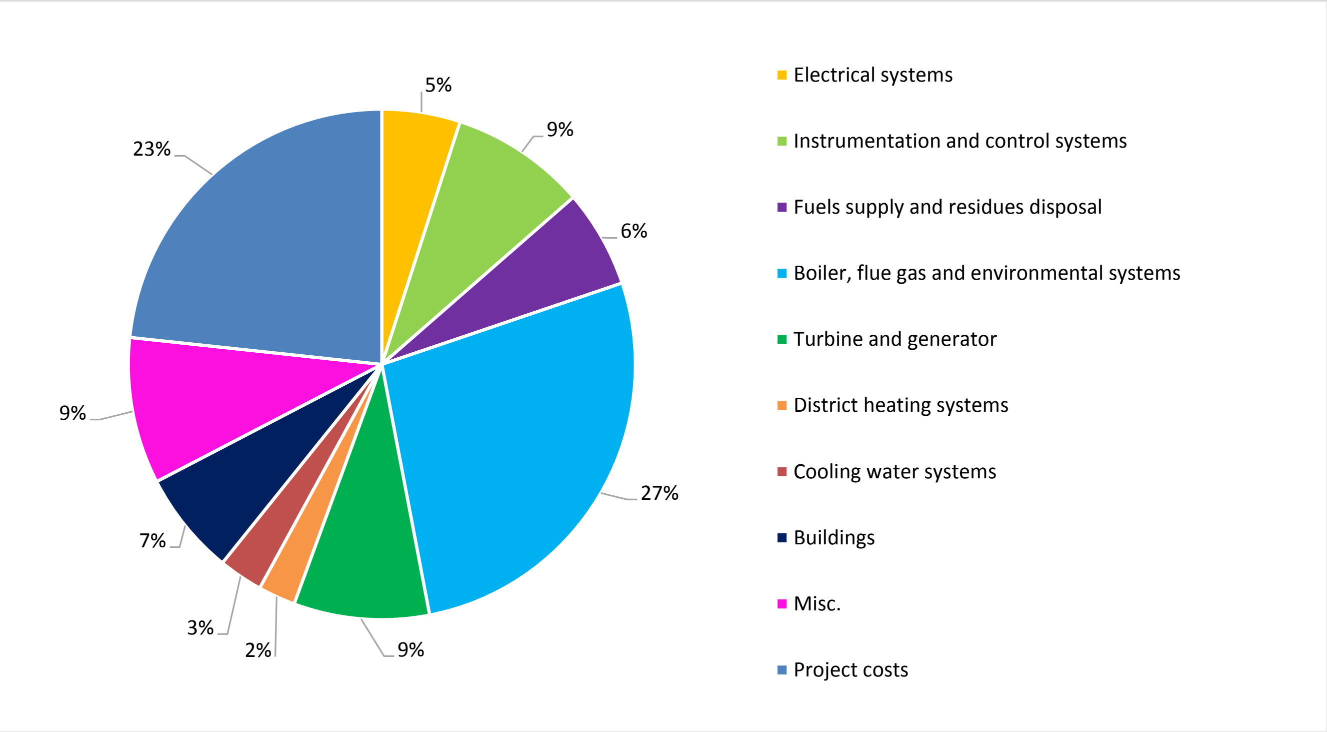


Figure 2: Diagram showing an example of the share of investment cost for an LTE project.

Life time extension of existing plants is also relevant when rebuilding to other fuels e.g. biomass as discussed in chapter 03 on conversion of power plants.

Input

Primary fuels are coal. Oil and/or natural gas are typically used for auxiliary start-up burners.

Output

The output is electricity and possibly heat for use in district heating systems.

Typical capacities

The capacity range considered is 200-400 MW_e.

Space requirement

The space requirements are not considered to change due to LTE.

Regulation ability and other power system services

The regulation abilities of coal fired power plants, e.g. start-up time and ramp rates may improve in connection with LTE due to implementation of better control systems [2]. This effect is, however, not possible to quantify on a general level. In general, start-up times and -costs are not considered to change due to LTE.

Advantages/disadvantages

Advantages

Life time extension of existing large coal fired power plants offers a relatively quick and easy solution to keep existing capacity in operation, since the costs are typically several times lower than investments in new capacity. Typical Danish power plants of age 20-25 years have quite high efficiencies and environmental performance compared with today's standard, so the difference in comparison to a new plant may not be crucial. The overall difference in efficiency compared to a new plant will be 3-5% points.

Disadvantages

One disadvantage is that the original performance data of the plant are difficult to alter significantly. Also, the future operation of coal fired plants is challenged by their environmental effects (especially CO_2 emissions), which may be deemed politically unacceptable on a medium to longer term.

Environment

The lifetime extension is not in itself expected to change the environmental performance characteristics beyond the maximum allowed emission values at the time of LTE, that probably are more stringent than the original requirements. If advantageous or required, such further improvements may be implemented in connection with LTE campaign.

Research and development perspectives

It is not anticipated that there will be a considerable further development in the technology relevant for life time extension of Danish large coal fired power plants. However, with the large number of coal power plants running world-wide, it is expected that LTE methods will generally improve.

Examples of market standard technology

The life time extension (LTE) of DONG Energy's Studstrupværket blok 3, 350 MW, 2012-2013 is one of the most recent Danish examples [3]. There have only been few recent LTE projects in Denmark.

Uncertainty

The investment costs of a LTE presented in the table are connected with relatively large uncertainties. The main reasons for this are the differences among the existing power plants in terms of design, technical condition, previous works carried out, etc. Also, some uncertainty is expected related to general variations of prices and markets in the energy sector, e.g. raw materials like steel and copper, and the supply situation in the construction sector.

Additional remarks

NIL

Data sheets

The following datasheet shows the technical, environmental and financial data for the specific technology. For more explanation, see the section about Quantitative description in the Introduction chapter. The columns "uncertainty" indicates the uncertainty or range of the parameter. The uncertainties only apply to the row, and cannot be read vertically, i.e. the lower uncertainty of the investment cost does not apply to the lower uncertainty of the capacity

Technology	Life time extension of coal power plant									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	300	300	300		200	400	200	400		
Electricity efficiency (condensation mode for extraction plants), net (%), name plate	+0	+0	+0		-1	+1			EF	7
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	+0	+0	+0		-1	+1			EF	7
Cb coefficient (50°C/100°C)	+0	+0	+0		+0	+0			AF	7
Cv coefficient (50°C/100°C)	+0	+0	+0		+0	+0			AF	7
Forced outage (%)	+0	+0	+0		+0	+0			AF	7
Planned outage (weeks per year)	+0	+0	+0		+0	+0			AF	7
Technical lifetime (years)	15	15	15							4, 5, 6, 7
Construction time (years)	0.5	0.5	0.5							7
Space requirement (1000m2/MW)	+0	+0	+0		+0	+0			AF	
Regulation ability										
Primary regulation (% per 30 seconds)	+0	+0	+0		+0	+0			AF	7
Secondary regulation (% per minute)	+0	+0	+0		+0	+0			AF	7
Minimum load (% of full load)	+0	+0	+0		+0	+0			AF	7
Warm start-up time (hours)	+0	+0	+0		+0	+0			AF	7
Cold start-up time (hours)	+0	+0	+0		+0	+0			AF	7
Environment										
SO_2 (degree of desulphuring, %)	+0	+0	+0		+0	+0			AFG	8
NO_X (g per GJ fuel)	+0	+0	+0		+0	+0			AFG	8
CH4 (g per GJ fuel)	+0	+0	+0		+0	+0			AFG	8
N2O (g per GJ fuel)	+0	+0	+0		+0	+0			AFG	8
Financial data										
Nominal investment (M€/MW)	0.24	0.24	0.24		0.15	0.34			CF	4, 5, 6, 7
- of which equipment	-	-	-		-	-				
- of which installation	-	-	-		-	-				
Fixed O&M (€/MW/year)	+0	+0	+0		+0	+8000			ABF	7
Variable O&M (€/MWh)	+0	+0	+0		+0	+0			ADF	7

Notes:

A Values will generally be similar to those of the plant prior to Life Time Extension (LTE).

B Values will depend on those of the plant prior to LTE, however the average fixed O&M cost may increase slightly for the extension period compared with the original life time to accommodate the necessary reinvestments during the extended life time.

C Investment costs will vary largely, depending on the necessary scope of work. The indicated range represents typical cases where 20-25 years Danish coal power CHP plants have been life time extended to obtain additional 15 years life time (based mainly on budgetted values).

D Variable O&M costs will in general be similar or a bit smaller to those of the plant prior to LTE. The reason for the small improvement is when you compare it to just before the LTE. When compared to the average over the lifetime the O&M costs will be similar.

E Values will generally be similar to those of the plant prior to LTE. Average efficiencies over the lifetime will be similar to the plant prior to LTE, but the efficiencies just after the LTE will be better than that of the plant just before the LTE.
F Values for year 2050 are not considered relevant since new coal fired power plants are not expected to be built
G It is assumed that plant emissions prior to the LTE are within the legal limits.

References

[1] Electricity Generation Costs, Department of Energy and Climate Change (UK), Dec 2013 [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf.

[2] R. Ambrosini, Life extension of coal-fired power plants, IEA, Dec 2005.

[3] AFTALE MELLEM DONG Energy Power A/S OG Aarhus Kommune VEDR. Betaling af omkostninger til levetidsforlængelse af Studstrupværkets produktionsblok 3 og fællesanlæg, Århus Kommune, April 2012. [Online]. Available: http://www.aarhus.dk/~/media/eDoc/C/1/2/C125711F0048D96EC12579C1004C66F3attach2.pdf

[4] Projected Costs of Generating electricity edition 2015, IEA, NEA and OECD, 2015

[5] Baggrundsnotat omhandlende metode for Energinet.dk's forventninger til kraftværksudviklingen i Danmark, Energinet.dk, 27. august 2014 (Background note concerning method for Energinet.dk's expectations for power plant development in Denmark , Energinet.dk , August 27, 2014).

[6] Studstrupværket kører videre på kul frem til 2015, Ingeniøren, 10. maj 2012, (Studstrupværket continues to run on coal until 2015, Engineer , May 10, 2012).

[7] Ea Energy Analysis, based on experience from various commercial projects.

[8] It is assumed by Ea Energy Analyses that plants emissions prior to the LTE is within the legal limits.

03 Rebuilding Large Coal Power Plants to Biomass

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Author: Ea Energy Analyses

Publication date

August 2016

Amendments after publication date

Date	Ref.	Description

Qualitative description

Brief technology description

Existing coal power plants may be rebuilt for biomass combustion, mainly in order to reduce CO_2 emissions without discarding existing generating capacity. The conversion to biomass in existing pulverized coal fired power plants may be done partly by co-firing a fraction of biomass together with the coal, or by converting the plant fully to biomass. The data and descriptions in this chapter only consider the full conversion options.

The power plants for rebuilding are assumed to be of age approximately 25 years meaning that a life time extension will be necessary in any case. Thus, the expected costs of lifetime extension are included for those parts of the plant that remain in operation after the rebuilding. It is further assumed that the rebuilt power plant will have a technical life time of 15 years, i.e. the O&M costs will cover the necessary refurbishments in this period.

The necessary works and associated costs for life time extension and rebuilding of existing power plants will in any case vary over a large span since the original power plants are all unique in terms of technical design and condition.

Coal power plants can be modified for biomass in a number of ways. Here the following three concepts are considered:

a) Wood pellets, existing boiler
b) Wood chips, new boiler
c) Wood chips, existing boiler

These options will determine the requirements for the necessary technical modifications and replacements of the fuel handling equipment, boiler systems etc. of the plants.

<u>a) Wood pellets</u>

The easiest and cheapest (concerning the investment costs) solution is to convert the fuel from coal to wood pellets, which is a fuel with the most similar characteristics to coal, meaning that the same boiler can be used. Pellets is a homogeneous and pre-dried fuel of various standardized qualities, produced from biomass material such as wood, wood residues, other energy crops or residues of agricultural production, etc., typically produced abroad and transported to the power plants in large vessels. The pellets have controlled water content, typically below 10% [1]. The energy consumption in the production of the pellets is around 10% of the energy content of the finished product [2], whereas the energy consumption for transportation depends on e.g. the type of ship, the distance and whether or not the ship is returning empty or with cargo. Shipping of pellets from Canada consume around 4% of the energy content in the finished product (efficient ship and full cargo), whereas transportation from the Baltic countries consume approximately 1.5% of the energy content of the finished product [3].

The figure below shows a principle sketch of the plant and which elements are expected to be added, replaced, or refurbished. Among these are:

- New storage silos and transport systems for the pellets
- Coal mills, to be modified and with extended capacity due to lower calorific value
- Larger fans for pneumatic transport systems
- New burners
- Boiler modifications , e.g. soot blowers to avoid deposits
- Other life time extensions, as relevant

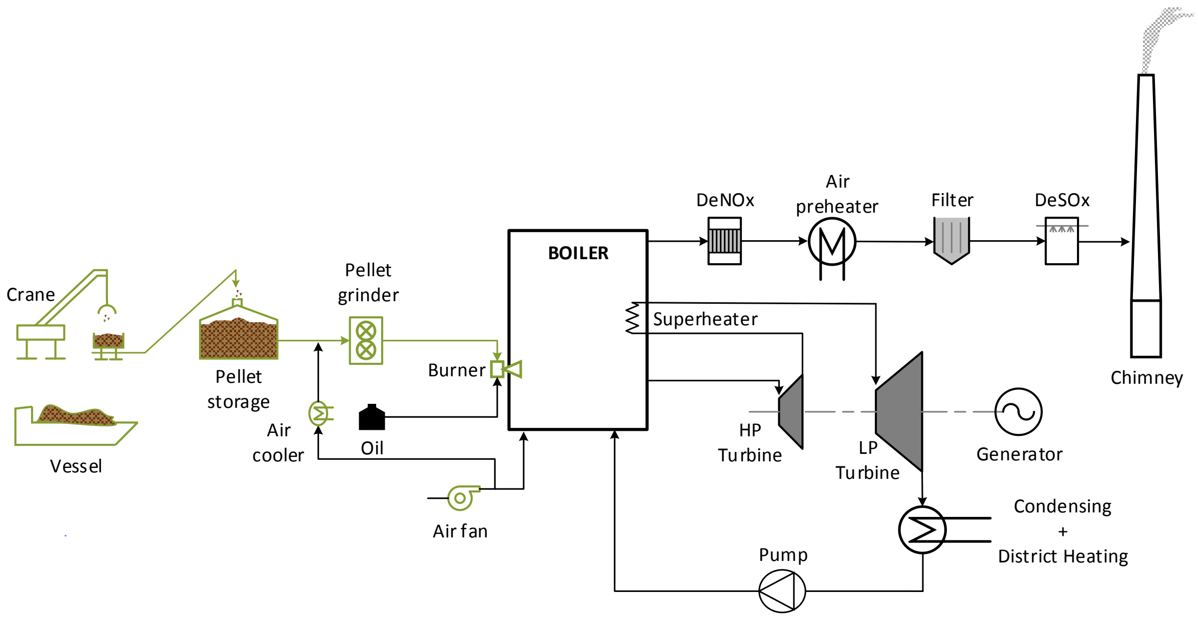


Figure 1: Sketch of a CHP plant converted to firing with wood pellets. The green elements indicate the equipment that needs to be added, replaced or refurbished.

The existing boilers, flue gas systems, and steam systems can be kept in operation with minor modifications done in connection with the life time extension. It should be considered to by-pass the desulphurization plant as the sulphur content in wood is much lower than in coal. This has been done on Amagerværket Unit 1 to attain higher efficiency. In such cases boiler efficiency and steam data will probably only be marginally affected. Since cold air is used for the fuel feeding less combustion air is heated in the air preheater, and subsequently the heat extracted from flue gas is less than in the original plant resulting in a minor reduction of the boiler efficiency. Application of flue gas condensation is not relevant due to the low water content of the pellets. In the boiler, increased formation of ash and slag deposits, e.g. corrosive chlorines, may normally be expected when shifting from coal to wood firing. This may be remedied by use of steam soot blowers. To improve the chemical processes and avoid deposits and dust formation, an amount of coal or fly ash from coal can be added to the boiler. The lower calorific value of wood compared with coal increases the necessary fuel amounts to approximately double volume. Storage of pellets requires new covered storage facilities. Therefore expansions of harbor facilities and land use for storage may be required. The possible additional costs for this are not considered.

It is here assumed that the boiler can be reused. In case existing boiler steam parameters are outdated or the boiler is worn out it can be beneficial to replace the boiler completely as done on Amagerværket Unit 1.

b) Wood chips, new boiler

Conversion of the fuel type from coal to wood chips requires major changes and is more time consuming and costly than conversion to pellets. However, this could be counterbalanced by a lower fuel price. One option for converting to wood chips is to install an entire new boiler. Wood chips are a less homogeneous fuel than pellets, with large variations in quality and size. Its water content is high, typically from 20% and up to more than 50%, and it may as well contain fractions of soil. The chipping can take place in the forest where smaller branches and treetops can also be used. Due to the low energy density and high water content wood chips are less suitable for transport over long distances and are most often locally sourced. However, logs can be transported by boat and chopped at the destination site.

The need for boiler replacement is due to the inability of the coal dust fired boiler to be adapted to the larger and inhomogeneous wood chips. For larger units > 200 MWth it is assumed that a circulating fluid bed (CFB) type furnace will be chosen (a chapter on large biomass circulating fluidized bed combustion systems (CFBC) will soon be included in the catalog), whereas bubbling fluid bed (BFB) and grate fired boilers are typically preferred for smaller units up to 150 MWth, but not feasible above this size due to physical limitations. For existing larger plants it is an option though, to build more than one grate fired boiler in parallel when converting to biomass. The data given here are based on the CFB type boiler. Due to the high water content in the fuel the boiler system will be equipped with flue gas condensation for increasing the heat output. The condensation will normally use the district heating return water, but further energy may be recovered by applying heat pumps (not considered in the data sheet).

The amount of condensate water is high due to the fuel's high moisture content. Therefore water treatment costs can be considerable.

Flue gas cleaning and dust filters need to be provided. Due to the lower combustion temperature in CFB the creation of NOx is lower than in other boilers [4, 5]. Still some kind of DeNOx plant probably is required. SCR (selective catalytic reduction) will probably be necessary to achieve the NOx emission limit value in the upcoming European standards [1]. A low duct tail end SCR can be integrated with flue gas cleaning [2]. Due to low sulfur content of woodchips, DeSOx is normally not required.

Further, the plant needs to be supplemented by a system for storage and handling of the wood chips, which can normally be stored outdoors. As for wood pellets expansions of harbor facilities and land use for storage may be required, but the possible additional costs for this are not considered here.

The figure below shows a principle sketch of the plant and which elements are expected to be added, replaced or refurbished. Among these are:

- New storage and transport systems for the wood chips
- New CFB boiler and air fans
- New high pressure turbine due to lower steam pressure. CFB boiler can also be made as super critical with high steam parameters
- New flue gas system, filters and condensation scrubber and probably also SCR
- Other life time extensions, as relevant

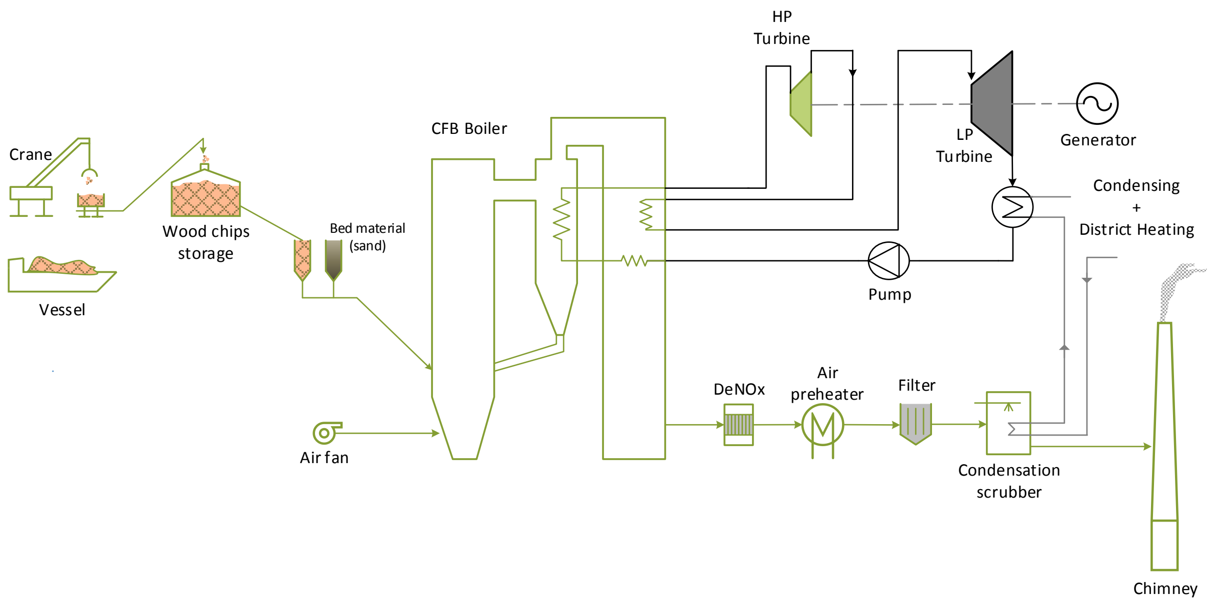


Figure 2: Sketch of a CHP plant converted to firing with wood chips with a new CFB boiler. The green elements indicate the equipment that needs to be added, replaced or refurbished.

<u>c) Wood chips, existing boiler</u>

[1] LCP BREF (140 mg NOx/Nm3 @ 6% O2 for plant above 100 MWth)

Another option for converting to wood chips is to reuse the existing boiler but install a plant for processing the chips into dry and fine grained matter, i.e. comparable to the fuel obtained by grinding wood pellets.

Thus, the existing boilers, flue gas systems, and steam systems can be kept in operation with minor modifications done in connection with the life time extension.

The water content of the wood chips must be lowered to usually below 10%, which may be achieved by adding a separate wood chip fired furnace or by using heat from the boiler flue gas. Before the drying the wood chips must be ground down to smaller sizes e.g. in hammer mills, depending on the quality of the raw material. After the drying the final grinding takes place for the fuel to be suitable for the dust-type burners.

Due to the large fuel volumes the storage and preparation plant may constitute a considerable extension of the existing plant. In the cost estimates, no potential expansions of harbor facilities and land use for storage are considered.

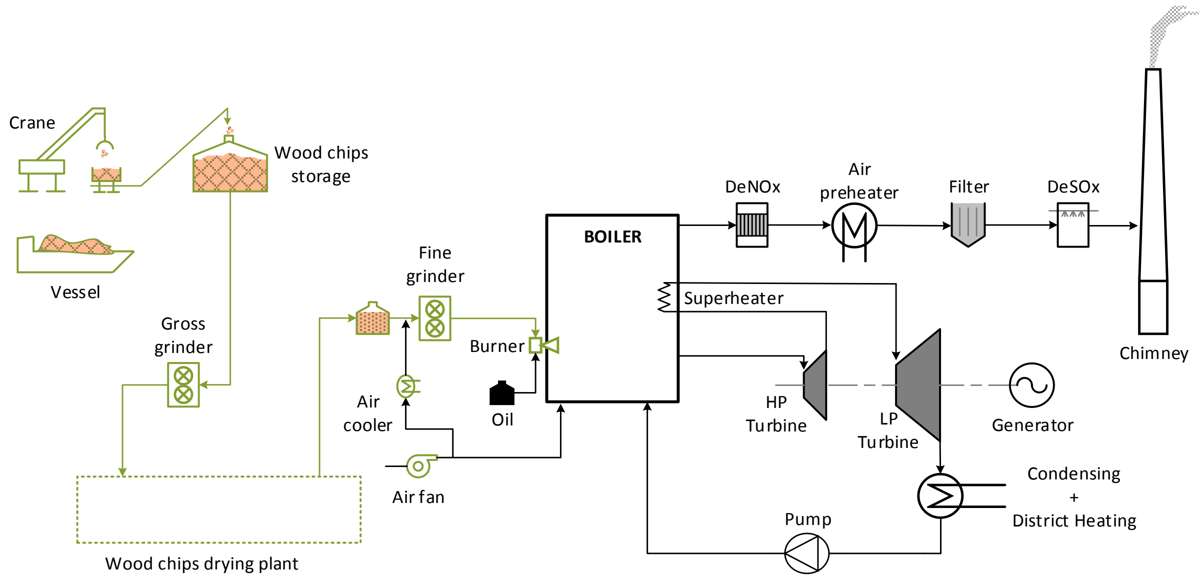


Figure 3: Sketch of a CHP plant converted to firing with wood chips with its existing boiler. The green elements indicate the equipment that needs to be added, replaced or refurbished.

As an alternative to converting the wood chips into pulverized fuel quality the boiler can be modified by installing a grate below the boiler. In such case the heat input on the grate is typically smaller than the original heat input and the plant is down rated accordingly.

Input

Primary fuels are biomass in the form of either a) dried and compressed wood pellets, or b) and c) Wood chips.

Output

The output is electricity and heat for use in district heating systems.

Typical capacities

The capacity range considered is in the range of 200-400 MW_e.

Regulation ability and other power system services

The regulation abilities will in most cases not change much, in case existing boilers of coal fired plants are rebuilt to biomass firing.

The regulation abilities of coal fired power plants with respect to primary and secondary load support are described in the Technology Catalogue item 01. The start-up times from cold state to initial generation for pulverized fuel (PF) and CFB boilers normally vary between 8 and 15 hours the higher end represent the CFB boilers. Typically, a power output of 25% of full capacity can be reached after 3 hours following the initial start-up time during which oil- or gas burners are used [6].

Start-up costs

The direct start-up costs include the fuel consumption for heating up boilers (which is not utilised for energy production), the electricity consumption, and other costs related to operation. The costs of a start-up also depend on the type of fuel used in the start-up period. As for a conventional plant it is normal to use oil or gas to pre-heat the boiler in a biomass converted plant, before the primary fuel is inserted. Thus, the direct start-up costs will not change much due to the shift of fuel from coal to biomass, assuming that fossil fuel could still be used for start-up purpose.

The indirect costs are the lost value corresponding to the lifetime reduction for one start up. For instance, during the heating-up, thermal and pressure variations will cause fatigue damage to components, and corrosion may increase in some areas due to e.g. condensation. This will depend on the initial plant.

Advantages/disadvantages

In general, rebuilding of coal fired power plants to biomass combustion is a relatively fast and cost effective way to reduce the use of fossil fuels (coal). Compared to building entire new units, investments are likely to be significantly lower. Also, the outage periods is likely to be shorter than if an entire new plant should be built at the same location as the one that is assumed rebuild. However, in case of building a new boiler and HP turbine, the advantage in time may not be significant.

One of the disadvantages is that the performance data will be more or less locked by those of the old plant, for instance the efficiencies will depend largely on the allowable steam temperature and pressure. The original plants may be 20-30 years old and therefore not fully live up to the standards of present technology regarding efficiencies etc. Compared to coal, the chemistry of wood combustion causes increased challenges with ash and slag formation and corrosion in the boiler. This makes it necessary to reduce the boiler and steam temperature slightly, and thereby the plant's electrical efficiency is typically also lowered a few percent.

The three rebuilding options have various advantages and disadvantages compared to each other. The use of pre-fabricated wood pellets offers a quick solution for rebuilding older coal power plant with less investment than the other options. On the other hand, the fuel costs are higher.

Wood chips are a cheaper fuel than wood pellets. However, in case of both replacing the boiler and building a fuel drying and processing plant, the investment is higher.

When installing a new boiler for combustion of wood chips, which have a relatively high water content, a higher heat efficiency can be obtained when recovering the condensation heat from the flue gas, though with a somewhat lower electric efficiency. Still, the overall fuel efficiencies may be higher and even above 100% (LHV).

In the case of a CFB-type boiler, and possibly also with converted boilers, the steam pressure is often lower than in the original plant and therefore the high pressure turbine has to be replaced with a new one. However a number of CFB suppliers are able to offer also super critical boilers. Otherwise, the pressure drop over the high pressure turbine will condense the steam too much, and the low pressure turbine will get steam that is too "wet" and will eventually break faster than it should.

It is common to add coal ashes or coal in the combustion of biomass to prevent slag formation and corrosion in the boiler, this will most likely make the ashes unsuitable for spreading in the environment. At the same time, the recycling of the ashes for use in concrete products, which is normal practice with coal ashes, is questionable with wood ashes due to its high alkali content. The ashes from firing with coal or biomass can be used for producing synthetic gypsum.

Environment

The environmental issues when using biomass as a fuel in rebuilt coal power plants are generally similar to those of new biomass plants. Central issues are emission of particulate matter, NO_x emissions and condensate water. Existing plant configuration often results in higher cost for flue gas cleaning than for new plants.

Another environmental issue is heavy metals in ashes. The ashes from biomass combustion contain minerals that are valuable in agriculture and forestry, and may be recycled. This is subject to regulation involving chemical analysis and controlling concentrations of heavy metals. Especially the cadmium and lead concentrations in the ashes will limit the amounts that can be spread over a certain area per year.

There are several specific health and safety issues connected with the transportation, handling and storage of wood pellets and chips. These involve e.g. the risk of suffocation, self-ignition, explosion, and formation of poisonous molds in storages and transport systems.

Research and development perspectives

Among the areas for further research activities within wood firing is the emission control and handling of residues.

Improvements in operation and maintenance may be gained when further experience is obtained, e.g. in process and emissions control, reduced corrosion rates, material selection for use in boilers, etc. In a wider perspective, a major area for discussion and development is the issue of sustainability connected with the sourcing of the wood material for fueling rebuilt power plants.

Examples of Market Standard technology

Conversion to wood pellets:

DONG Energy Avedøreværket Unit 1, 254 MW_e, ongoing, expected completed in 2016.

DONG Energy has converted several other power plant units to biomass, for example Skærbækværket in 2015-2017 and Herningværket in 2002 and 2009. [7].

GDF Suez plant, Poland, 205 MW_e 2012.

HOFOR Amagerværket Unit 1 pulverized fuel plant converted to wood pellets and a small fraction of straw pellets in 2009.

Prediction of performance in the future

As the technologies for rebuilding power plants have reached a mature stage, only incremental improvements of processes and equipment can be expected. These are largely driven by the emission limitation requirements and therefore not likely to lead to significant cost reductions.

Specific operation and maintenance issues with large biomass units can still be improved along with further experience being gained, and this knowledge can be utilized for converted coal units as well.

In principle, rebuilding will only be interesting as long as existing coal power plants are available, which offer financially interesting investments in competition with other electricity generation technologies.

Uncertainty

The relatively large uncertainty intervals in the investment costs for the rebuilding options reflect mainly the following, in order of magnitude:

- The existing power plants are quite different in terms of design, technical condition size etc. This will widely influence the necessary works for life time extension and adding of new equipment in connection with rebuilding projects.
- There is some uncertainty expected related to general variations of prices and markets in the energy sector, e.g. raw materials like steel and copper, and the supply situation in the construction sector.

Data sheets

The following datasheet shows the technical, environmental and financial data for the specific technology. For more explanation see the section about Quantitative description in the Guideline chapter. The boxes “uncertainty” indicate the uncertainty or range of the parameter. The uncertainty only applies to the row, and cannot be read vertically, i.e. the lower uncertainty of the investment cost does not apply to the lower uncertainty of the capacity.

Technology	Rebuilding power plants from coal to biomass a) Wood pellets									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	300				200	400				
Electricity efficiency (condensation mode for extraction plants), net (%), name plate	-1	-1	-1		-0	-2			ABC	10
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	-1	-1	-1		-0	-2			ABC	10
Cb coefficient (50°C/100°C)	-0,02	-0,02	-0,02		-0	-0,05			ABC	10
Cv coefficient (50°C/100°C)	+0	+0	+0		-0.01	+0,01			AC	10
Forced outage (%)	+0	+0	+0		-1	+1			A	10
Planned outage (weeks per year)	+0	+0	+0		+0	+0			A	10
Technical lifetime (years)	15	15	15						C	10
Construction time (years)	2	2	2		1.5	2.5			CH	10
Space requirement (1000m2/MW)	+0	+0	+0		+0	+0			AD	
Regulation ability										
Primary regulation (% per 30 seconds)	+0	+0	+0		+0	+0			A	10
Secondary regulation (% per minute)	+0	+0	+0		+0	+0			A	10
Minimum load (% of full load)	+0	+0	+0		+0	+0			A	10
Warm start-up time (hours)	+0	+0	+0		+0	+0			A	10
Cold start-up time (hours)	+0	+0	+0		+0	+0			A	10
Environment										
SO_2 (degree of desulphuring, %)	-	-	-		-	-				
NO_X (g per GJ fuel)	38	35	35		19	53			G	
CH4 (g per GJ fuel)	3.1	3.1	3.1		3.1	3.1			G	
N2O (g per GJ fuel)	0.8	0.8	0.8		0.8	0.8			G	
Financial data										
Nominal investment (M€/MW)	0.57	0.56	0.55		0.4	1.1			CE	10/11/12
- of which equipment	-	-	-		-	-				
- of which installation	-	-	-		-	-				
Fixed O&M (€/MW/year)	+8600	+8600	+8600		+5700	+11400			AF	10
Variable O&M (€/MWh)	+0	+0	+0		+0	+1			AF	10

Notes:

A Value depend on the original plant. Value indicate the estimated change from the original value (unit is the same as the paramter).

B Typically the electricity efficiency will be 1-2 % point lower than that of the plant prior to conversion. The thermal efficiency is typically unchanged, thus the Cb value decreases, meaning more heat is produced compared to electricity.

C Values for year 2050 are not considered relevant since it is assumed that all coal fired plants in Denmark have been rebuilt or decommissioned.

D Some additional under roof space (or silos) will be required for storage of pellets compared to coal (estimated 50%-100% extra m3 storage). But not more floor space (m2).

E	The nominal investment assumes that the original plant is aged and therefore include investment for a general life time extension campaign
F	The variable O&M costs will be similar to those of the original plant, however fixed O&M costs are likely to increase by 10-20%
G	Assumed the same emission values from the datasheet of new biomass plants (wood chips). See references and notes in the datasheet '09 Biomass CHP, Steam Turbine - Large steam turbine, Woodchips'.
H	From financing and permits are at hand, to commission of the plant.

Technology	Rebuilding power plants from coal to biomass b) Wood chips, new boiler									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	300				200	400				
Electricity efficiency (condensation mode for extraction plants), net (%), name plate	-1	-1	-1		-0	-2			AB	10
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	-1	-1	-1		-0	-2			AB	10
Cb coefficient (50°C/100°C)	-0,07	-0,07	-0,07		-0.02	-0,1			AB	10
Cv coefficient (50°C/100°C)	+0	+0	+0		-0.01	+0,01			A	10
Forced outage (%)	+0	+0	+0		-1	+1			A	10
Planned outage (weeks per year)	+0	+0	+0		+0	+0			A	10
Technical lifetime (years)	15	15	15						C	10
Construction time (years)	2.5	2.5	2.5		2	3			CH	10
Space requirement (1000m2/MW)	+0,03	+0,03	+0,03		+0,02	+0,05			AD	10
Regulation ability										
Primary regulation (% per 30 seconds)	-2	-0	-0		-0	-5			AI	10
Secondary regulation (% per minute)	-2	-0	-0		-0	-5			AI	10
Minimum load (% of full load)	+0,05	+0,05	+0		+0	+0,1			A	10
Warm start-up time (hours)	+0,5	+0,5	+0		+0	+2			AI	10
Cold start-up time (hours)	+1	+1	+1		+0	+2			AI	10
Environment										
SO_2 (degree of desulphuring, %)	-	-	-		-	-				
NO_X (g per GJ fuel)	55	35	35		19	53			G	
CH4 (g per GJ fuel)	0.5	0.5	0.5		0	0.5			G	
N2O (g per GJ fuel)	5	5	5		2	20			G	
Financial data										
Nominal investment (M€/MW)	1.6	1.6	1.6		1.3	2.1			CE	10/12
- of which equipment	-	-	-		-	-				
- of which installation	-	-	-		-	-				
Fixed O&M (€/MW/year)	+8600	+8600	+8600		+5700	+11400			F	10
Variable O&M (€/MWh)	+1	+1	+1		+0.5	+2			F	10

Notes:

A Value depend on the original plant.

B Typically the electricity efficiency will be 1-2 % point lower than that of the plant prior to conversion. The thermal efficiency will typically increase to around 105%, thus the Cb value decreases, meaning more heat is produced compared to electricity. This is mainly due to implementation of exhaust gas condenser.

C Values for year 2050 are not considered relevant since it is assumed that all coal fired plants in Denmark have been rebuilt or decommissioned.

D Some additional space will be required for storage of chips (estimated 50%-100% extra).

E The nominal investment assumes that the original plant is aged and therefore include investment for a general life time extension campaign

F The fixed O&M costs are likely to increase by 10-20%, whereas the variable O&M costs are likely to increase approx. 50%.

G Emission values from the datasheet of new CFB biomass plants. See references and notes in the datasheet 'Large Biomass Circulating Fluidized Bed Combustion Systems (CFBC) for wood'.

H From financing and permits are at hand, to commission of the plant.

I The regulation time of the boiler will often increase, due to slower burning of chips compared to pulverized fuel. Depending of the other thermal limitations in the cycle (e.g. in the turbines) this will have no change or an increase in the regulation time.

Technology	Rebuilding power plants from coal to biomass c) Wood chips, existing boiler									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	300				200	400				
Electricity efficiency (condensation mode for extraction plants), net (%), name plate	-3	-3	-3		-2	-4			AB	10
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	-3	-3	-3		-2	-4			AB	10
Cb coefficient (50°C/100°C)	-0,07	-0,07	-0,07		-0.02	-0,1			AB	10
Cv coefficient (50°C/100°C)	+0	+0	+0		-0.01	+0,01			A	10
Forced outage (%)	+0	+0	+0		-1	+1			A	10
Planned outage (weeks per year)	+0	+0	+0		+0	+0			A	10
Technical lifetime (years)	15	15	15						C	10
Construction time (years)	2	2	2		1.5	2.5			CH	10
Space requirement (1000m2/MW)	+0,04	+0,04	+0,04		+0,03	+0,06			AD	10
Regulation ability										
Primary regulation (% per 30 seconds)	+0	+0	+0		+0	+0			A	10
Secondary regulation (% per minute)	+0	+0	+0		+0	+0			A	10
Minimum load (% of full load)	+0	+0	+0		+0	+0			A	10
Warm start-up time (hours)	+0	+0	+0		+0	+0			A	10
Cold start-up time (hours)	+0	+0	+0		+0	+0			A	10
Environment										
SO_2 (degree of desulphuring, %)	-	-	-		-	-				
NO_X (g per GJ fuel)	38	35	35		19	53			G	
CH4 (g per GJ fuel)	3.1	3.1	3.1		3.1	3.1			G	
N2O (g per GJ fuel)	0.8	0.8	0.8		0.8	0.8			G	
Financial data										
Nominal investment (M€/MW)	1.6	1.6	1.6		1.3	2.1			CE	10
- of which equipment	-	-	-		-	-				
- of which installation	-	-	-		-	-				
Fixed O&M (€/MW/year)	+26000	+26000	+26000		+20000	+30000			F	10
Variable O&M (€/MWh)	+1	+1	+1		+0.5	+2			F	10

Notes:

A Value depend on the original plant.

B Typically the electricity efficiency will be 3-4 % point lower than that of the plant prior to conversion. The thermal efficiency is increased to approximately 100% because of flue gas condensation in drying process, thus the Cb value decreases, meaning more heat is produced compared to electricity.

C Values for year 2050 are not considered relevant since it is assumed that all coal fired plants in Denmark have been rebuilt or decommissioned.

D Some additional space will be required for storage of chips (estimated 50%-100% extra) and for the drying plant.

E	The nominal investment assumes that the original plant is aged and therefore include investment for a general life time extension campaign
F	Both variable and fixed O&M costs are likely to increase by 40-50% from the original plant.
G	Assumed the same emission values from the datasheet of new biomass plants (wood chips). See references and notes in the datasheet '09 Biomass CHP, Steam Turbine - Large steam turbine, Woodchips'.
H	From financing and permits are at hand, to commission of the plant.

References

[1] Biomass pelleting, European Biomass Industry Association, 2015. http://www.eubia.org/index.php/about-biomass/biomass-pelleting

[2] Status overview of torrefaction technologies – IEA Bioenergy Task 32, Koppejan et. al, 2012.

[3] Analysis of biomass prices – future Danish prices for straw, wood chips and wood pellets, Ea Energy Analyses for Danish Energy Agency, 2013.

[4] Circulating fluidised bed technology - clean, efficient & fuel-flexible, Alstom, 2013. http://alstomenergy.gepower.com/Global/Power/Resources/Documents/Brochures/circulating-fluidised-bed-boiler-technology-coal-oil-power-epslanguage=en-GB.pdf

[5] Dansk Gasteknisk Center A/S, 2013.

[6] Assessment of startup period at coal-fired electric generating units, EPA 2013.

[7] DONG Energy Power plans and experience in Biomass, Presentation Jesper Staal. https://www.essent.eu/content/Images/90684_04_DONG%20plans%20in%20biomass_Jesper%20Staal.pdf

[8] Recirkulering af aske i skov -tekniske, økonomiske og økologiske aspekter, I. Callesen, S. Skov og N. Heding, Arbejdsrapport Skov & Landskab nr. 7-2004.

[9] Informed by BWE A/S, Dec. 2015.

[10] Ea Energy Analysis, based on experience from various commercial projects.

[11] Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012, UK Department of Energy and Climate Change, July 2012.

[12] A strategy for converting coal fueled power plants to biomass, Future Metrics, September 2014

04 Gas Turbine, Simple-Cycle

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Author: Dansk Gasteknisk Center

Publication date

August 2016

Amendments after publication date

Date	Ref.	Description

Qualitative description

Brief technology description

The major components of a simple-cycle (or open-cycle) gas turbine power unit are: a gas turbine, a gear (when needed) and a generator. For cogeneration (combined heat and power production), a flue gas heat exchanger (hot water or steam) is also installed, see the diagram below.

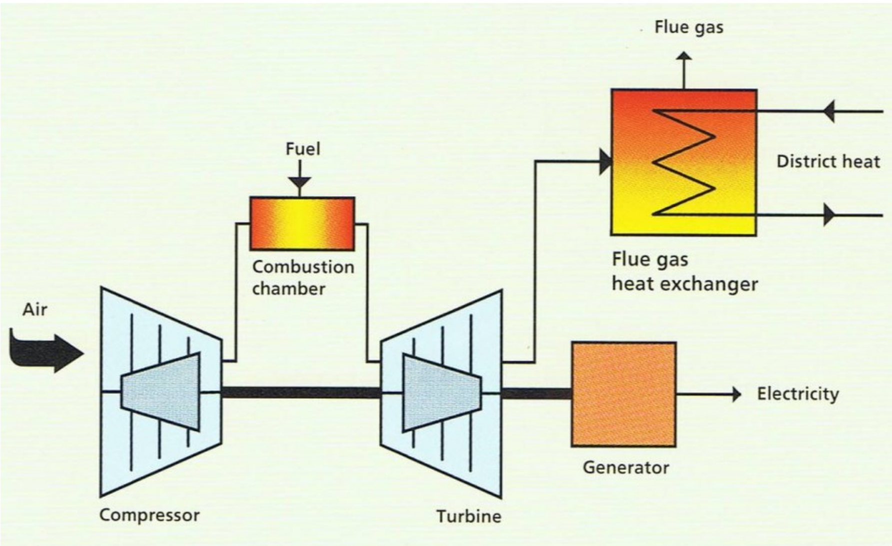


Figure 1 Diagram of a simple cycle plant designed for combined heat and power production.

If applying heat pumps for extra cooling of the exhaust gas, even higher total fuel efficiency can be reached. Depending on priorities, the flue gas heat pumps can be electrical or absorption type.

Simple cycle gas turbines can be used for preheating the feed water of steam power plants. This is the case at the Danish Avedøre 2 power station.

There are in general two types of gas turbines;

1. industrial turbines (also called heavy duty)

2. aero-derivative turbine

Industrial gas turbines differ from aero-derivative turbines in the way that the frames, bearings and blading are of heavier construction. Additionally, industrial gas turbines have longer intervals between services compared to the aero-derivatives.

Aero-derivative turbines benefit from higher efficiency than industrial ones and the most service-demanding module of the aero-derivative gas turbine can normally be replaced in a couple of days, thus keeping a high availability.

Gas turbines can be equipped with compressor intercoolers where the compressed air is cooled to reduce the power needed for compression. The use of integrated recuperators (preheating of the combustion air) to increase efficiency can also be made by using air/air heat exchangers - at the expense of an increased exhaust pressure loss. Gas turbine plants can have direct steam injection in the burner to increase power output through expansion in the turbine section (Cheng Cycle). Direct steam injection is not common for turbines in Denmark

Small (radial) gas turbines below 100 kWe are now on the market, the so-called micro-turbines. These are often equipped with preheating of combustion air based on heat from gas turbine exhaust (integrated recuperator) to achieve reasonable electrical efficiency (25 - 30 %).

Input

Typical fuels are natural gas and light oil. Some gas turbines can be fuelled with other fuels, such as LPG, biogas etc., and some gas turbines are available in dual-fuel versions (gas/oil).

Gas fired gas turbines need an input pressure of the fuel (gas) of 20-60 bar, dependent on the gas turbine compression ratio, i.e. the entry pressure in the combustion chamber. Typically, aero derivative gas turbines need higher fuel (gas) pressure than industrial types.

Output

Electricity and heat (optional). All heat output is from the exhaust gas and is extracted by a flue gas heat exchanger (heat recovery boiler).

The heat output is usually either as steam or hot water.

Typical capacities

Simple-cycle gas turbines are available in the 30 kWe – 450 MWe range [1].

The enclosed data tables cover large scale (40 – 125 MW), medium and small scale (5 - 40 MW) installations. Data on micro gas turbines (0.03 – 0.100 MW) is also presented.

All data are for gas turbines operating in simple cycle cogeneration mode without flue gas condensation, if no additional notes are made.

Regulation ability and other power system services

A simple-cycle gas turbine can be started and stopped within minutes, supplying power during peak demand. Because they are less power efficient than combined cycle plants, they are in most places used as peak or reserve power plants, which operate anywhere from several hours per day to a few dozen hours per year.

However, every start/stop has a measurable influence on service costs and maintenance intervals. As a rule-of-thumb, a start costs 10 hours in technical life expectancy [5].

The flue gas heat exchanger (heat recovery boiler) may lead to some constraints on start-up gradients. This can be solved by including a flue gas bypass.

Gas turbines are able to operate at part load. This reduces the electrical efficiency and at lower loads the emission of e.g. NOx and CO will increase. The increase in NOx emissions with decreasing load places a regulatory limitation on the regulation ability. This can be solved in part by adding de-NOx units.

The heat produced from cooling of the exhaust gas can be either hot water (for district heating or low-temperature process needs) or steam for process needs. Variations in steam production may be achieved by varying the gas turbine load, by supplementary firing in the heat recovery boiler or via a bypass stack.

To operate a simple cycle gas turbine of a cogeneration plant in power-only mode, the exhaust gas is directed to a bypass stack.

Most simple cycle gas turbine plants installations for CHP include short time heat storage. This leads to more flexibility in production planning.

Advantages/disadvantages

Advantages

Simple-cycle gas turbine plants have short start-up/shut-down time, if needed. For normal operation, a hot start will take some 10 - 15 minutes [5,6]. Construction times for gas turbine based simple cycle plants are shorter than steam turbine plants [6].

Disadvantages

Concerning larger units above 15 MW, the combined cycle technology has so far been more attractive than simple cycle gas turbine, when applied in cogeneration plants for district heating [3]. Steam from other sources (e.g. waste fired boilers) can be led to the steam turbine part as well. Hence, the lack of a steam turbine can be considered a disadvantage for large-scale simple cycle gas turbines.

Environment

Gas turbines have continuous combustion with non-cooled walls. This means a very complete combustion and low levels of emissions (other than NOx). Developments focusing on the combustors have led to low NOx levels as stated elsewhere. To lower the emission of NOx further, post-treatment of the exhaust gas can be applied, e.g. with SCR catalyst systems.

Research and development perspectives

Increased efficiency for simple-cycle gas turbine configurations has also been reached through inter-cooling and recuperators. Research into humidification (water injection) of intake air processes (HAT) is expected to lead to increased efficiency due to higher mass flow through the turbine.

Additionally continuous development for less polluting combustion is taking place. Low-NOx combustion technology is assumed. Water or steam injection in the burner section may reduce the NOx emission, but also the total efficiency and thereby possibly the financial viability. The trend is more towards dry low-NOx combustion, which increases the specific cost of the gas turbine [3]

Examples of market standard technology

The best technology on the marked today is a medium size gas turbines with integrated recuperator that can reach approx. 38 % electrical efficiency (5 MWe unit).

Prediction of performance and costs

Gas turbine technology is a well-proven commercial technology with numerous power generating installations worldwide, making simple cycle gas turbines a category 4 technology. Technological improvements are continuously being made; new materials, new surface treatments or improved production methods can lead to higher electrical efficiency, improved lifetime and less service needs.

Developments now also focus on broader gas quality acceptance during operation and improved dynamic performance.

The efficiency of the simple-cycle turbine can be increased, if inlet temperatures to the turbine section can be increased. Therefore development of ceramic materials that can withstand high temperatures used in the hot parts of the gas turbine is taking place.

However, the expectations for the gas turbine market in Denmark are limited, since gas turbines are currently predominantly used in the reserve power market. This means that no significant reductions in investment and/or operation/maintenance costs are expected to be seen in the years to come. In a longer perspective, gas turbines may become relevant for green gas based power production.

Uncertainty

Uncertainty stated in the tables both covers differences related to the power span covered in the actual table and differences in the various products (manufacturer, quality level, extra equipment, service contract guarantees etc.) on the market.

A span for upper and lower product values is given for the year 2020 situation. No sources are available for the 2050 situation. Hence the values have been estimated by the authors.

Additional remarks

Figures for service and maintenance costs are usually based on generated electricity. Service contract may also be on this basis; pricing may be influenced by the number of starts/stops.

Data sheets

Technology	Gas turbine, simple cycle (large)									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	40 - 125								F	
Electricity efficiency (condensation mode for extraction plants), net (%)	41	42	43	45	38	42	40	44		6, 12
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	39	40	41	43	36	40	38	42		6, 11
Cb coefficient (50°C/100°C)	0.95	0.96	1	1	0.8	1.2	0.8	1.2		6, 12
Cv coefficient (50°C/100°C)	-	-	-	-	-	-	-	-	J	
Forced outage (%)	2	2	2	2	2	3	2	3		6
Planned outage (weeks per year)	3	3	2.5	2.5	2	3.5	1.5	3		6
Technical lifetime (years)	25	25	25	25	25	>25	25	>25	E	6, 7
Construction time (years)	1.5	1.5	1.5	1.5	1	2	1	2		6
Space requirement (1000m2/MW)	0.02	0.02	0.02	0.02	0.015	0.03	0.015	0.03	G	7
Plant Dynamic Capabilities										
Primary regulation (% per 30 seconds)	0	0	0	0	0	0	0	0	I	
Secondary regulation (% per minute)	20	20	20	20	20	50	20	50	C	6
Minimum load (% of full load)	25	23	20	20	20	25	20	25	A	6
Warm start-up time (hours)	0.25	0.23	0.2	0.2	0.1	0.5	0.1	0.4		5, 6, 8
Cold start-up time (hours)	0.5	0.5	0.5	0.5	0.4	1	0.4	1		5, 6, 8
Environment										
SO_2 (degree of desulphuring, %)	0	0	0	0	0	0	0	0		
NO_X (g per GJ fuel)	20	15	10	10	10	30	7.5	20	D	7, 9
CH4 (g per GJ fuel)	1.5	1.5	1.5	1.5	1	8	1	8	G	9
N2O (g per GJ fuel)	1.0	1.0	1.0	1.0	0.7	1.2	0.7	1.2	G	9
Financial data										
Nominal investment (M€/MW)	0.6	0.59	0.56	0.52	0.4	0.9	0.35	0.85		6, 10
- of which equipment	NA	NA	NA	NA	NA	NA	NA	NA	K	
- of which installation	NA	NA	NA	NA	NA	NA	NA	NA	K	
Fixed O&M (€/MW/year)	20000	19500	18600	18000	NA	NA	NA	NA	B	6
Variable O&M (€/MWh)	4.5	4.4	4.2	4	4	6	3	5		6

Technology	Gas turbine, simple cycle (small and medium scale plant)									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	5 - 40								F	
Electricity efficiency (condensation mode for extraction plants), net (%)	36	37	39	40	32	40	34	42	G, H	6, 12
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	34	35	37	38	30	38	32	40		6, 11
Cb coefficient (50^{o}C/100^{o}C)	0.71	0.73	0.8	0.8	0.61	0.8	0.7	0.9		6, 12
Cv coefficient (50^{o}C/100^{o}C)	-	-	-	-	-	-	-	-	J	
Forced outage (%)	2	2	2	2	2	3	2	3		6
Planned outage (weeks per year)	3	2.8	2.5	2.5	2	3.5	1.5	3		6
Technical lifetime (years)	25	25	25	25	25	>25	25	>25	E	6, 7
Construction time (years)	1.5	1.5	1.5	1.5	1	1.5	1	1.5		6
Space requirement (1000m2/MW)	0.04	0.04	0.04	0.04	0.03	0.07	0.03	0.07	G	7
Plant Dynamic Capabilities										
Primary regulation (% per 30 seconds)	0	0	0	0	0	0	0	0	I	
Secondary regulation (% per minute)	20	20	20	20	20	50	20	50	C	6
Minimum load (% of full load)	25	23	20	20	20	25	20	25	A	6
Warm start-up time (hours)	0.25	0.23	0.2	0.2	0.1	0.5	0.1	0.4		5, 6, 8
Cold start-up time (hours)	0.5	0.5	0.5	0.5	0.4	1	0.4	1		5, 6, 8
Environment										
SO_2 (degree of desulphuring, %)	0	0	0	0	0	0	0	0		
NO_X (g per GJ fuel)	20	15	10	10	10	30	8	20	D	7, 9
CH4 (g per GJ fuel)	1.5	1.5	1.5	1.5	1	8	1	8		9
N2O (g per GJ fuel)	1.0	1.0	1.0	1	0.7	1.2	0.7	1.2		9
Financial data										
Nominal investment (M€/MW)	0.75	0.73	0.70	0.68	0.6	1	0.55	0.95		6, 10
- of which equipment	NA	NA	NA	NA	NA	NA	NA	NA	K	
- of which installation	NA	NA	NA	NA	NA	NA	NA	NA	K	
Fixed O&M (€/MW/year)	20000	19500	18600	18000	NA	NA	NA	NA	B	6
Variable O&M (€/MWh)	5.5	5.4	5.1	4.6	5	7	4	6		6

Technology	Gas turbine, simple cycle (micro)									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	0.015 - 0.200									
Electricity efficiency (condensation mode for extraction plants), net (%)	30	30	30	30	23	32	25	35	M	7
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	28	28	28	28	21	29	23	33		
Cb coefficient (50°C/100°C)	0.6	0.6	0.6	0.6	0.4	0.85	0.4	0.85		7, 13
Cv coefficient (50°C/100°C)	-	-	-	-	-	-	-	-	J	
Forced outage (%)	5	5	5	5	NA	NA	NA	NA		
Planned outage (weeks per year)	NA	NA	NA	NA	NA	NA	NA	NA		
Technical lifetime (years)	15	15	15	15	10	20	10	20	L	
Construction time (years)	0.5	0.5	0.5	0.5	0.3	0.8	0.2	0.7	L	13
Space requirement (1000m2/MW)	0.06	0.06	0.06	0.06	0.05	0.15	0.05	0.15		7
Plant Dynamic Capabilities										
Primary regulation (% per 30 seconds)	0	0	0	0	0	0	0	0		
Secondary regulation (% per minute)	0	0	0	0	0	0	0	0		
Minimum load (% of full load)	40	40	40	40	30	50	25	50	L	7, 13
Warm start-up time (hours)	0.25	0.25	0.25	0.25	NA	NA	NA	(NA)		
Cold start-up time (hours)	0.5	0.5	0.5	0.5	NA	NA	NA	(NA)		
Environment										
SO_2 (degree of desulphuring, %)	0	0	0	0	0	0	0	0		13
NO_X (g per GJ fuel)	10	10	10	10	6	15	6	15		7, 13
CH4 (g per GJ fuel)	6	6	6	6	NA	NA	NA	NA		13
N2O (g per GJ fuel)	NA	NA	NA	NA	NA	NA	NA	NA		13
Financial data										
Nominal investment (M€/MW)	1.2	1.2	1.1	1.0	NA	NA	NA	NA		13, 14
- of which equipment	0.85	0.85	0.8	0.7	NA	NA	NA	NA		13, 14
- of which installation	0.35	0.35	0.3	0.3	NA	NA	NA	NA		13, 14
Fixed O&M (€/MW/year)	NA	NA	NA	NA	NA	NA	NA	NA		
Variable O&M (€/MWh)	15	15	14	13	10	15	8	15		13

Notes:

A Very low efficiency at low loads and often increased Nox emisison

B Insurance excluded, unknown. Daily start assumed

C Power related

D Based on Dry Low NOx (DLN) techniques

E Technical- and design life most often > 25 years

F Electrical output

G Combined with DGC assumptions, CHP configuration

H GT's (5 MWe) are available including internal recuperator; the electrical nominal efficiency is then 37 % (LCV basis)

I No data available, no known use

J Not relevant for this CHP configuration

K No data available

L DGC Estimate

M Air preheating by internal recuperation included

References

[1] Major Gas Turbine Suppliers product information available on the Web, 2015 (Online).

[2] Diesel & Gas Turbine World Wide Catalogue, Brookfield, US (annual publication).

[3] Cogeneration and On-site Power Production, Ltd., Penwell International.

[4] Opportunities for Micropower and Fuel Cell/Gas Turbine Hybrid Systems in Industrial Applications, A. D. Little, US, 2000.

[5] Danish Gas Technology Centre, Analysis on gas engine and gas turbine dynamics, 2013.

[6] Wärtsila Technical Journal in detail 02-2014.

[7] Data specs from manufacturers, 2015 (Web).

[8] Danish Gas Technology Centre, Analysis and discussion with manufacturers, April 2013.

[9] Danish Gas Technology Centre, Environmental survey, 2012.

[10] Smart Power Generation - The future of electricity production, J. Klimstra & M. Hotakainen, 2011.

[11] IEA: Projected cost of generating electricity, 2010.

[12] COWI 2015 input.

[13] The Omes Project results, 2005.

[14] WBDG-Publication, B. L. Capehart, Microtubines, 2014.

05 Gas Turbine Combined-Cycle

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Energinet.dk: Rune Grandal, rdg@energinet.dk
Author: Dansk Gasteknisk Center

Publication date

August 2016

Amendments after publication date

Date	Ref.	Description
January 2018	05 Combined cycle gas turbine	Additional references have been included

Qualitative description

Brief technology description

Main components of combined-cycle gas turbine (CC-GT) plants include: a gas turbine, a steam turbine, a gear (if needed), a generator, and a heat recovery steam generator (HRSG)/flue gas heat exchanger, see the diagram below.

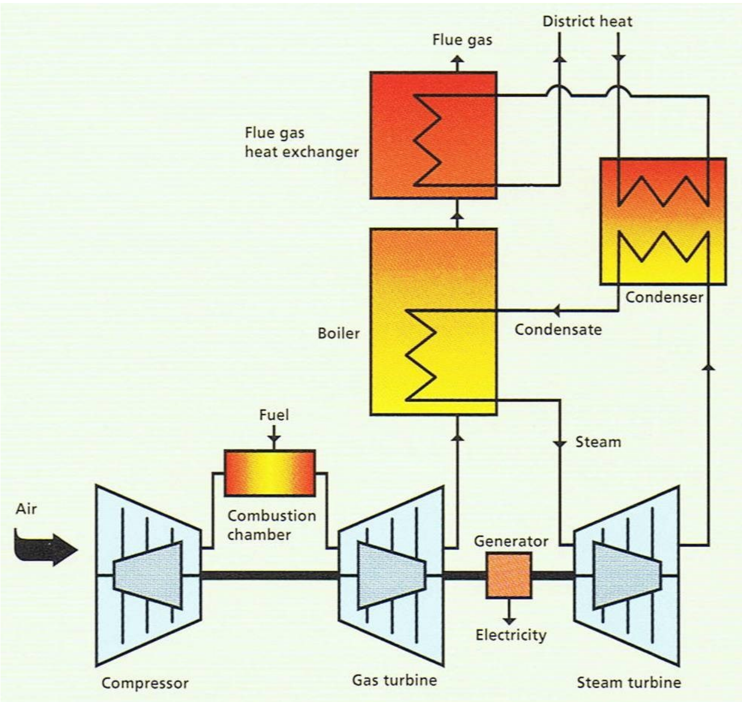


Figure 1 Diagram showing an example of a CC-GT plant designed for combined heat and power production.

The gas turbine and the steam turbine are shown driving a shared generator. In real plants, the two turbines might drive separate generators. Where the single-shaft configuration contributes with higher reliability, the multi-shaft has a slightly better overall performance.

The condenser is cooled by the return water from the district heating network. Since this water is afterwards heated by the flue gas from the gas turbine, the condensation temperature can be fairly low.

The overall energy efficiency depends on the flue gas stack temperature, while the electricity efficiency depends, besides the technical characteristics and the ambient conditions, on the district heating flow temperature. However, some plants do not have the option to sell district heating, and the condenser is therefore cooled by a sea/river/lake or a cooling tower.

If applying heat pumps for extra cooling of the exhaust gas, even higher total fuel efficiency can be reached. Depending on priorities, the flue gas heat pumps can be electrical or absorption type.

The heat recovery steam generator (HRSG) is defined through the number of pressure levels, each producing steam for the steam turbine. Small, medium and large scale units usually have one or two steam pressure stages whereas very large units may have three steam pressure stages. Steam is fed to the turbine both at the inlet and at a later stage between the two adjacent steam turbine sections; this is one of the special features of steam turbines in CC-GT.

Plants being able to shift between condensation mode (power only) and back-pressure mode (power and district heat) include a so-called extraction steam turbine. Such turbines are not available in small sizes, and dual-mode plants are therefore only feasible in large scale.

The power generated by the gas turbine is typically two to three times the power generated by the steam turbine. An extraction steam turbine shifting from full condensation mode at sea temperature to full back-pressure mode at district heat return temperature will typically lose about 10% of its electricity generation capacity. For example, a 40 MW gas turbine combined with a 20 MW steam turbine (condensation mode), loses 2 MW, (10% of 20 MW) or 3% of the total generating capacity (60 MW).

Input

Typical fuels are natural gas and light oil. Some gas turbines can be fuelled with other fuels, such as LPG, biogas etc., and some gas turbines are available in dual-fuel versions (gas/oil).

Gas fired gas turbines need a fuel gas pressure of 20-60 bar, typically aero-derivative gas turbines need higher pressure than industrial gas turbines.

Additional steam from other sources may be fed to the steam turbine section.

Output

Electricity and heat. The heat is most often supplied as hot water.

Typical capacities

The enclosed datasheets cover large scale CC-GT (100 – 400 MW with extraction steam turbine) and medium scale (10 – 100 MW with back pressure steam turbine).

Most CC-GT units has an electric power of > 40 MWe

Regulation ability and other power system services

CC-GT units are to some extent able to operate at part load. This will reduce the electrical efficiency and often increase the NOx emission.

If the steam turbine is not running, the gas turbine can still be operated by directing the hot flue gasses through a boiler designed for high temperature or into a bypass stack.

The larger gas turbines for CC-GT installations are usually equipped with variable inlet guide vanes, which will improve the part-load efficiencies in the 85-100 % load range, thus making the part-load efficiencies comparable with conventional steam power plants in this load range. Another means to improve part-load efficiencies is to split the total generation capacity into several CC-GTs. However, this will generally lead to a lower full load efficiency compared to one larger unit.

The NOx emission is generally increased during part load operation.

Some suppliers have developed CC-GT system designs enabling short start up both regarding the electrical output and the steam circuit as well.

Most CC-GT plants installations include a short time heat storage. This leads to more flexibility in production planning.

Advantages/disadvantages

Advantages

Large gas turbine based combined-cycle units are world leading with regard to electricity production efficiency among fuel based power production.

Smaller CC-GT units have lower electrical efficiencies compared to larger units. Units below 20 MWe are few and will face close competition with single-cycle gas turbines and reciprocating engines.

Gas fired CC-GTs are characterized by low capital costs, high electricity efficiencies, short construction times and short start-up times.

Disadvantages

The economies of scale are substantial, i.e. the specific cost of plants below 200 MWe increases as capacity decreases.

The high air/fuel ratio for gas turbines leads to lower overall efficiency for a given flue gas cooling temperature compared to steam cycles and cogeneration based on internal combustion engines.

Environment

Gas turbines have continuous combustion with non-cooled walls in the combustion chamber. This means a very complete combustion and low levels of emissions (except for NO_x). Developments focusing on the combustor(s) have led to low NO_x levels.

Flue gas post-treatment can consist of SCR catalyst systems etc.

Research and development perspectives

Continuous research is done concerning higher inlet temperature at first turbine blades to achieve higher electricity efficiency. This research is focused on materials and/or cooling of blades.

Continuous development for less polluting combustion is taking place. Increasing the turbine inlet temperature may increase the NOx production. To keep a low NOx emission different options are at hand or are being developed, i.e. dry low-NOx burners, catalytic burners etc.

Development to achieve shorter time for service is also being done.

Examples of market standard technology

Large CC-GT units have demonstrated an electrical efficiency of 60 % (LHV reference). Systems are now being offered and built with an electrical efficiency close to 62 %. The units are large units with an output in the 500 – 600 MWe [3].

In 2009, Eon opened one of the most efficient power plants in Europe, the CHP plant Öresundsverket in Malmö, Sweden. The 440 MW CC-GT has an electrical efficiency of 58% and an overall fuel efficiency in full cogeneration mode of 90%. The total investment figure for the project was €300 million [12].

Prediction of performance and costs

Gas turbine based combined cycle plants are a well-proven, widespread and available technology, making CC-GT a category 4 technology. Improvements are still being made primarily on the gas and steam turbines used. Developments for faster load response and dynamic capabilities are now also in focus. In [13] examples is given for a large (>250 MWe) CC-GT plant with full GT power in less than 15 minutes and approx. 70 % power supply from the steam turbine. Full steam turbine power is achieved in less than one hour.

The expected market in Denmark is limited and declining for the time being. This means that no significant reductions in investment and/or operation/maintenance cost is expected in the years to come. In a longer perspective, gas turbines or gas turbine combined cycle plants may become relevant for green gas based balancing power.

Uncertainty

Uncertainty stated in the tables both covers differences related to the power span covered in the actual table and differences between the various products (manufacturer, quality level, extra equipment, service contract guarantees etc.) on the market.

A span for upper and lower product values is given for the year 2020 situation. No sources are available for the 2050 situation. Hence the values have been estimated by the authors.

Additional remarks

The main rotating parts (the gas turbine, steam turbine and the generator) tend to account for around 45-50% of the investment costs (EPC price), the heat recovery steam generator, condenser and cooling system for around 20%, the balance of plant components for around 15%, the civil works for around 15% and the remainder being miscellaneous other items [10].

Data sheets

Technology	Gas turbine, combined cycle (steam extraction)									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	100 - 500								F	
Electricity efficiency (condensation mode for extraction plants), net (%),	58	59	61	63	55	61	58	65		5
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	55	56	58	60	52	58	55	62		5, 9
Cb coefficient (50°C/100°C)	1.7	1.8	2	2.2	1.5	2.2	1.5	2.4		
Cv coefficient (50°C/100°C)	0.15	0.15	0.15	0.15	N.A	N.A	N.A	N.A	J	
Forced outage (%)	3	3	3	3	2	4	2	4		5
Planned outage (weeks per year)	2.5	2.3	2	2	2	4	2	4		5
Technical lifetime (years)	25	25	25	25	25	>25	25	>25	E	5, 3
Construction time (years)	2.5	2.5	2.5	2.5	2	3	2	3		5
Space requirement (1000m2/MW)	0.02	0.02	0.02	0.02	0.015	0.03	0.015	0.03	G	3
Plant Dynamic Capabilities										
Primary regulation (% per 30 seconds)	-	-	-	-	-	-	-	-	K	
Secondary regulation (% per minute)	15	15	15	15	5	15	5	15		5, 3, 11
Minimum load (% of full load)	40	40	40	40	30	50	30	50	A	5, 3, 11
Warm start-up time (hours)	1	1	1	1	0.5	1.5	0.5	1.5	H	5, 6, 1, 11
Cold start-up time (hours)	2.5	2.5	2.5	2	2	5	1.5	5		5, 6, 1, 11
Environment										
SO_2 (degree of desulphuring, %)	0	0	0	0	0	0	0	0		
NO_X (g per GJ fuel)	20	15	10	8	10	30	5	15	D	3, 7
CH4 (g per GJ fuel)	1.5	1.5	1.5	1.5	1	8	1	8	G	7
N2O (g per GJ fuel)	1	1	1	1	0.7	1.2	0.7	1.2	G	7
Financial data										
Nominal investment (M€/MW)	0.9	0.88	0.83	0.8	0.8	1.2	0.7	1.1		5, 8
- of which equipment	0.7	0.68	0.64	0.61	0.65	1.02	0.6	0.95		10

- of which installation	0.2	0.20	0.19	0.19	0.15	0.18	0.1	0.15		10
Fixed O&M (€/MW/year)	30000	29300	27800	26000	25000	35000	20000	30000	B	5
Variable O&M (€/MWh)	4.5	4.4	4.2	4	3	7	3	7		5

Technology	Gas turbine, combined cycle (back-pressure)									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	10 -100								F	
Electricity efficiency (condensation mode for extraction plants), net (%),	50	51	53	55	42	55	45	58		5
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	47	48	50	52	39	52	42	55		5, 9
Cb coefficient (50^{o}C/100^{o}C)	1.2	1.3	1.4	1.55	0.9	1.6	1.1	1.7		
Cv coefficient (50^{o}C/100^{o}C)	-	-	-	-	-	-	-	-	L	
Forced outage (%)	3	3	3	3	2	4	2	4		5
Planned outage (weeks per year)	2.5	2.3	2	2	2	4	1.5	4		5
Technical lifetime (years)	25	25	25	25	25	>25	25	>25	E	5, 3
Construction time (years)	2.5	2	2	2	2	3	2	3		5
Space requirement (1000m2/MW)	0.025	0.025	0.025	0.025	0.019	0.038	0.019	0.038	G	3
Plant Dynamic Capabilities										
Primary regulation (% per 30 seconds)	-	-	-	-	-	-	-	-	I	
Secondary regulation (% per minute)	15	15	15	15	5	15	5	15	C, M	5, 3, 11
Minimum load (% of full load)	40	40	40	40	30	50	30	50	A	5, 3, 11
Warm start-up time (hours)	1	1	1	1	0.5	1.5	0.5	1.5	H	5, 6, 1, 11
Cold start-up time (hours)	2.5	2.5	2.5	2	2	5	1.5	5		5, 6, 1, 11
Environment										
SO_2 (degree of desulphuring, %)	0	0	0	0	0	0	0	0		
NO_X (g per GJ fuel)	20	15	10	8	10	30	5	15	D	3, 7
CH4 (g per GJ fuel)	1.5	1.5	1.5	1.5	1	8	1	8	G	7
N2O (g per GJ fuel)	1	1	1	1	0.7	1.2	0.7	1.2	G	7
Financial data										
Nominal investment (M€/MW)	1.3	1.3	1.2	1.1	1.1	1.8	0.9	1.6		5, 9
- of which equipment	1	1.0	0.9	0.8	0.8	1.4	0.65	1.25		10
- of which installation	0.3	0.3	0.3	0.3	0.3	0.4	0.25	0.35		10
Fixed O&M (€/MW/year)	30000	29300	27800	26000	25000	35000	20000	30000	B	5
Variable O&M (€/MWh)	4.5	4.4	4.2	4	3	7	3	7		5

Notes:

A Low efficiency at low loads and often increased NOx emission

B Limited availability of data

C Power related

D Based on Dry Low NOx (DLN) techniques

E Technical- and design life most often > 25 years

F Electrical output

G CHP configuration, Including DGC assumptions

H Manufacturers says down to 30 minute

I No data available

J Data on Cv from the 2012 version roughly adjusted for higher electricity efficiency

K No known use

L No Relevance for Back Pressure Lay Out

M Upward regulation is typically 10 - 15 %/min, while downward regulation is > 30 % /min

References

[1] Danish Gas Technology Centre, Analysis on Gas Engine and Gas Turbine Dynamics, 2013.

[2] Major Gas Turbine Suppliers product information available on the Web, 2015 [Online].

[3] Data specs from manufacturers (Web), 2015.

[4] Opportunities for Micropower and Fuel Cell/Gas Turbine Hybrid Systems in Industrial Applications, A. D. Little, US, 2000.

[5] Wärtsila Technical Journal in detail 02-2014.

[6] Danish Gas Technology Centre, Analysis and discussion with manufacturers, April 2013.

[7] Danish Gas Technology Centre, Environmental survey, 2012.

[8] Smart Power Generation - The future of electricity production, J. Klimstra & M. Hotakainen, 2011.

[9] IEA: Projected cost of generating electricity, 2010.

[10] UK Electricity Generation Costs Update, M.M. Donald, June 2010.

[11] Siemens: Data on GT-CC, 2010.

[12] EuroHeat&Power, vol. 6, III/2009

[13] Siemens Flex-Plant™ CC-GT concepts, presentations 2013

06 Gas Engines

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Energinet.dk: Rune Grandal, rdg@energinet.dk
Author: Dansk Gasteknisk Center

Publication date

August 2016

Amendments after publication date

Date	Ref.	Description
January 2018	06 Gas engines	Reference sheet have been updated

Qualitative description

Brief technology description

A gas engine for co-generation of heat and power drives an electricity generator for the power production. Electrical efficiency up to 45- 48 % can be achieved. The engine cooling water (engine cooling, lube oil and turbocharger intercooling) and the hot exhaust gas can be used for heat generation, e.g. for district heating or low-pressure steam.

In district heating systems with low return temperatures both sensible and latent heat in the exhaust gas can be recovered by using a condensing cooler as the final cooling of the flue gasses and a total efficiency of approx. 96-98% can be reached. If applying heat pumps for extra cooling of the exhaust gas system, 5-7% higher total efficiency can be reached. The flue gas heat pumps can be electrical or absorption type.

Two combustion concepts are available for spark ignition engines; lean-burn and stoichiometric combustion engines. Lean-burn engines have a high air/fuel-ratio. The combustion temperature and hence the NOx emission is thereby reduced. The engines can be equipped with oxidation catalysts for CO-reduction.

In stoichiometric combustion engines, the amount of air is just sufficient for (theoretically) complete combustion. For this technology, the NOx emission must be reduced in a 3-way catalyst. Only few of such engines are used for combined heat and power production in Denmark. These engines are usually in the lowest power range (< 150 kWe).

Pre-chamber lean-burn combustion system is a common technology for engines with a bore size typically larger than 200 mm. This technology helps to maximize electrical efficiency and increases combustion stability along with low NOx emissions.

Another ignition technology is used in dual-fuel engines. A dual-fuel engine (diesel-gas) with pilot oil injection is a gas engine that - instead of spark plugs - uses a small amount of light oil (1 - 6%) to ignite the air-gas mix by compression (as in a diesel engine). Dual fuel engines can often operate on diesel oil alone as well as on gas with pilot oil for ignition.

More than 800 gas engines for combined heat and power production are installed in Denmark [4].

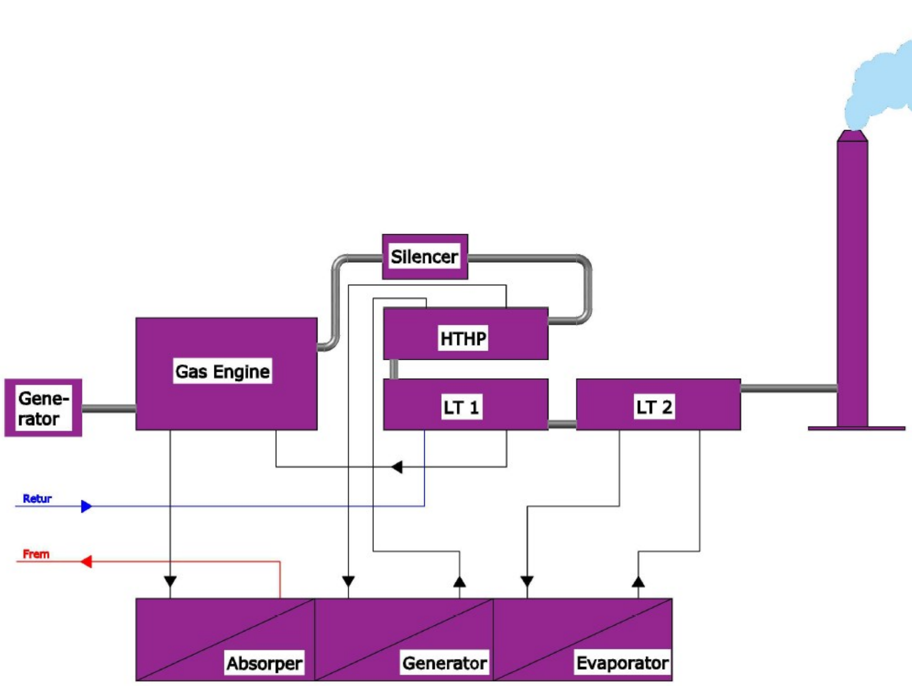


Figure 1 A gas engine based cogeneration unit with heat recovery boilers and an absorption heat pump to obtain a high heat production and highest possible overall efficiency. The heat pump is steam driven [9].

Input

Gas, e.g. natural gas, biogas, landfill gas, special gas and syngas (from thermal gasification) can be input to gas engines. Multi-fuel engines are also on the market, and installations are in service in Denmark and abroad.

In recent years, engines have been developed to use gasses with increasingly lower heating values.

Output

Electricity and heat (district heat; low-pressure steam; industrial drying processes; absorption cooling) are output of the gas engine.

Typical capacities

5 kW_e - 10 MW_e per engine.

Regulation ability and other power system services

Gas engines can start faster than most other electricity production technologies. For many engines 5-15 minutes are needed. Large gas engines have been successfully developed and tested for start to full electrical load in less than one minute. Engines have been developed for fuel switch during operation [7].

Part load is possible with only slightly decreased electric efficiency. The dual-fuel engines have the least decrease of efficiency at part load. Gas engines have better part load characteristics than gas turbines.

To operate a gas engine in power-only mode, the exhaust gas can be emitted directly to the atmosphere without heat extraction (but with de-NOx if required), whereas engine heat (about 50% of total heat) must be removed by a cooler. Approximately 10% of O&M costs can be saved in power-only mode [7].

Most gas engine based CHP plants installations include a short time heat storage. This leads to more flexibility in production planning.

Advantages/disadvantages

Advantages

Gas engines are known and proven technology making it a highly reliable technology.

Gas engines can operate on moderate gas pressures. Gas engines can be supplied by a gas pressure of less than 1 bar(g). The pre-chamber lean-burn technology often requires a pressure for the pre-chambers of approx. 4 bar(g).

Disadvantages

Gas engines cannot be used to produce considerable amounts of high-pressure steam, as approx. 50 % of the waste heat is released at lower temperatures.

Environment

Spark ignition engines comply with national regulations within EU by using catalyst and/or lean-burn technology to reduce the NOx emission.

The content of other air pollutants than NOx in the flue gas from a gas engine is generally low.

Research and development perspectives

Multi-fuel or flexible fuel operation has been introduced, and R&D efforts are continuously put into this. Engines with almost instantaneous shift from gas to diesel and vice versa have been developed and demonstrated.

Short start-up, fast load response and other grid services are becoming more important as more fluctuating power sources are supplying power grids. Gas engines have a potential for supplying such services, and R&D efforts are put into this.

R&D in further emission reduction is continuously taking place; biogas and other such gasses may lead to new catalytic post treatment solutions.

Examples of market standard technology

Best available technology from an efficiency point of view will be a large gas engine with approx. 48-50 % electrical efficiency and a total fuel efficiency of some 106% if fitted with an absorption heat pump using the outlet flue gas as heat source.

Engine based cogeneration units can be fitted with a small low pressure steam turbine for extra power generation.

From a grid service point of view (power balancing and backup) engines with a start to full electrical load in less than one minute is the best available technology.

Prediction of performance and costs

Cogeneration based on gas engines is a proven and commercial technology in Denmark and abroad. Development still takes place mostly related to advanced control and diagnostic systems, making gas engines a category 4 technology. Development also takes place related to efficiency improvements, auxiliary equipment as heat pumps and/or heat driven cooling systems (tri-generation).

Gas engines are now being developed for wider acceptance of various fuel compositions. This includes operation on upgraded biogas.

Even higher electrical production efficiency can be reached by including small low pressure steam turbines to the shaft. This is being tested and supplied to some larger gas engine makes; it improves the mechanical/electrical efficiency by 2-4 percentage points.

A number of gas engine based cogeneration plants have increased their heat output and the total overall efficiency by including heat driven absorption heat pumps in the cogeneration system configuration. The outlet flue gas can be cooled to a temperature less than the available cooling water, and total efficiencies up to approx. 106% have been achieved.

For shorter start-up time services, new designs/solutions on the water side are needed to avoid sudden temperature disturbances in the heat supply.

The expected market in Denmark is limited and declining as well as the annual operation hours. This means that no significant reductions in investment and/or operation/maintenance cost are expected to be seen in the years to come.

Uncertainty

Uncertainty stated in the tables both covers differences related to the power span covered in the actual table and differences between the various products (manufacturer, quality level, extra equipment, service contract guarantees etc.) on the market.

A span for upper and lower product values is given for the year 2020 situation. No sources are available for the 2050 situation. Hence the values have been estimated by the authors.

Additional remarks

The information given in tables is for gas fired (n-gas and biogas) engines only. The natural gas basis is the natural gas supplied in Denmark according to regulations. The biogas basis is a methane/CO2 mixture (digestion of manure and/or industrial organic waste).

Data sheets

Technology	06 Spark ignition engine, natural gas									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	1 -10 MWe									
Electricity efficiency (condensation mode for extraction plants), net (%)	46	47	48	50	40	48	44	52	A	3, 4
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	44	45	47	48	38	46	42	50	A	3, 4, 7
Cb coefficient (50°C/100°C)	0,9	0,95	0,99	1,04	0,65	1,02	0,65	1,15		3, 4, 7
Cv coefficient (50°C/100°C)	-	-	-	-	-	-	-	-	G	
Forced outage (%)	3	3	3	3	2	5	2	5		5, 6
Planned outage (weeks per year)	0,8	0,8	0,8	0,8	N.A	N.A	N.A	N.A	H	5, 6
Technical lifetime (years)	25	25	25	25	25	>25	25	>25	D	4, 5, 7
Construction time (years)	1	1	1	1	0,5	1,5	0,5	1,5	B	3, 6
Space requirement (1000m2/MW)	0,04	0,04	0,035	0,03	0,03	0,05	0,025	0,04		
Plant Dynamic Capabilities										
Primary regulation (% per 30 seconds)	25	30	35	50	10	40	25	100		12
Secondary regulation (% per minute)	25	30	40	50	20	100	25	100	C	6, 12, 13
Minimum load (% of full load)	50	50	50	50	30	50	25	50		6
Warm start-up time (hours)	0,05	0,05	0,05	0,05	0,015	0,15	0,015	0,15	C	6, 10
Cold start-up time (hours)	0,3	0,3	0,3	0,3	0,2	0,4	0,2	0,4	E	6, 10
Environment										
SO_2 (degree of desulphuring, %)	0	0	0	0	0	0	0	0		4
NO_X (g per GJ fuel)	75	60	60	60	50	100	50	100		4
CH4 (g per GJ fuel)	315	315	280	250	300	400	250	350		4
N2O (g per GJ fuel)	0,6	0,6	0,6	0,6	N.A	N.A	N.A	N.A	H	
Financial data										
Nominal investment (M€/MW)	1	0,95	0,9	0,85	0,9	1,1	0,8	1,1		3, 5, 11
- of which equipment	0,65	0,6	0,55	0,55	N.A	N.A	N.A	N.A	H	3, 5
- of which installation	0,35	0,35	0,35	0,3	N.A	N.A	N.A	N.A	H	3, 5
Fixed O&M (€/MW/year)	10000	9750	9300	8500	7000	20000	6000	15000	F	5
Variable O&M (€/MWh)	5,4	5,4	5,1	4,9	4	12	4	10	F	3, 5, 11

Technology	06 Spark ignition engine, biogas									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	1-10 MWe									
Electricity efficiency (condensation mode for extraction plants), net (%),	42	43	45	47	38	44	42	48	A	3, 4
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	40	41	43	45	36	42	40	46	A	3, 4, 7
Cb coefficient (50°C/100°C)	0,82	0,86	0,92	1	0,59	0,96	0,75	1,1		3, 4, 7
Cv coefficient (50°C/100°C)	-	-	-	-	-	-	-	-	G	
Forced outage (%)	3	3	3	3	2	5	2	5		5, 6
Planned outage (weeks per year)	1	1	1	1	N.A	N.A	N.A	N.A	H	5, 6
Technical lifetime (years)	25	25	25	25	25	>25	25	>25	D	4, 5, 7
Construction time (years)	1	1	1	1	0,5	1,5	0,5	1,5	B	3, 6
Space requirement (1000m2/MW)	0,04	0,04	0,035	0,03	0,03	0,05	0,025	0,05		
Plant Dynamic Capabilities										
Primary regulation (% per 30 seconds)	25	30	40	50	10	40	25	100	J	8
Secondary regulation (% per minute)	25	30	40	50	20	100	25	100	C	6, 8, 13
Minimum load (% of full load)	50	50	50	50	30	50	25	50		6
Warm start-up time (hours)	0,05	0,05	0,05	0,05	0,015	0,15	0,015	0,15	C	6, 10
Cold start-up time (hours)	0,3	0,3	0,3	0,3	0,2	0,4	0,2	0,4	E	6, 10
Environment										
SO_2 (degree of desulphuring, %)	(I)	(I)	(I)	(I)	0	99,9	0	99,9	K	8
NO_X (g per GJ fuel)	100	100	100	100	90	120	90	120		4
CH4 (g per GJ fuel)	300	300	300	300	300	400	300	400		4
N2O (g per GJ fuel)	1,0	1,0	1,0	1,0	N.A	N.A	N.A	N.A	J	
Financial data										
Nominal investment (M€/MW)	1	0,95	0,9	0,85	0,8	1,2	0,8	1,2		3, 5, 11
- of which equipment	0,65	0,6	0,55	0,55	N.A	N.A	N.A	N.A		3, 5
- of which installation	0,35	0,35	0,35	0,3	N.A	N.A	N.A	N.A		3, 5
Fixed O&M (€/MW/year)	10000	9750	9300	8500	7000	20000	6000	15000	F	5
Variable O&M (€/MWh)	8	7,5	7	6	6	13	4	12	F	3, 5, 11

Notes:

A Ref 1, 2 and 3 is used for 2015 values for 3 - 10 MWe engine, 1 MWe engine 4-5 % points less. Ref 4 & 5 is used for predictions for the future years.

B The construction time given is for a medium size installation; small installations can be erected in a shorter period

C Engines have been build and demonstrated for short start up < 1 minute for full electrical load. This includes large engines

D Technical- and design life most often > 25 years

E For a medium size engine; small engines with less thermal mass might be faster

F When operating 4000 hours a year

G Only relevant for steam based CHP

H No data available

I DGC estimate for years 2030, 2050

J No known use, data from n-gas engines

K Sulphur is removed in the biogas processing, according to manufactures spec. Lower values for biogas from waste water

References

[1] Cogeneration and On-site Power Production, Ltd., Penwell International.

[2] Opportunities for Micropower and Fuel Cell/Gas Turbine Hybrid Systems in Industrial Applications, A. D. Little, US, 2000.

[3] ASUE BHKW Kenndata 2014/2015.

[4] DGC statistics, Efficiency and emission test reports.

[5] DGC analysis, The gas fired cogeneration sector, Bilagsrapport 9, Energiforligsanalyse 2013.

[6] Features and parameters of various power plant technologies, Wartsila In Detail 02-2014 etc.

[7] Dansk Fjernvarme and FDKV reports from CHP installations, the Dansk Fjernvarme information is from a 2012 survey for an earlier version of the report.

[8] Ongoing Sulpur research project at DGC (MUDP).

[9] AEA.dk

[10] Danish Gas Technology Centre, Analysis on gas engine and gas turbine dynamics, 2013.

[11] Blockheizkraftwerke 2013, M. Buller et al, GWF Gas Erdgas, Juni 2014.

[12] Suppliers association information etc.

[13] MAN Turbo Presentation of Gas Engine with fuel switch, 2012

07 CO_2 Capture and Storage (go to previous catalogue)

There are no plans to update this chapter.
For now please look at the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

08 Waste to Energy CHP Plant (updated datasheet available)

For technical descriptions of the technologies go to previous catalogue. In this catalogue a common qualitative description of the the technology sheets of biomass and waste fired plants (chapter 08, 09, 42 and 43) are presented in chapter 99 in this publication.

The specific chapter for *Waste to Energy CHP Plant* is under review. The old version (2012/2015) is found in the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

Data sheets WtE CHP, small

Notes and references are commen for all the datasheets and can be found below the last data sheet.

Technology	**Small Waste to Energy CHP, Back pressure turbine, 35 MW feed**									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	7,9	7,9	8,2	8,3	7,3	8,5	7,3	9,1	A, B	
Incineration capacity (Fuel input) (tonnes/h)	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	A, B	
Electricity efficiency, net (%), name plate	22,6	22,6	23,5	23,7	20,9	24,3	20,9	25,9	A, B,C	
Electricity efficiency, net (%), annual average	21,4	21,4	22,3	22,5	18,8	23,1	18,8	24,6	A, B,C	
Heat efficiency, net (%), name plate	78,5	78,5	77,8	78,6	75,5	82,8	72,3	84,5	A, B	
Heat efficiency, net (%), annual average	79,6	79,6	79,0	79,8	77,6	84,1	74,4	85,8	A, B, C	
Additional heat potential with heat pumps (% of thermal input)	4,1	4,1	4,0	3,8	2,0	5,1	1,9	5,1	A, B, D	
Cb coefficient (40°C/80°C)	0,29	0,29	0,30	0,30	0,27	0,31	0,27	0,33	A, B	
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	A, B	
Forced outage (%)	1	1	1	1	1	1	1	1		1
Planned outage (weeks per year)	3,5	3,3	3,0	2,5	2,8	3,8	1,8	3,1	E	1
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	2,5	2,5	2,5	2,5	2	3	1,5	3		1
Space requirement	2,5	2,5	2,4	2,4	2,2	2,9	1,8	3,0		1

(1000 m2/MWe)										
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA	F	
Secondary regulation (% per minute)	10	10	10	10	10	10	10	10	F, G	
Minimum load (% of full load)	20	20	20	20	20	20	20	20	F, G	
Warm start-up time (hours)	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	F, G	
Cold start-up time (hours)	2	2	2	2	2	2	2	2	F, G	
Environment										
SO_2 (degree of desulphuring, %)	99,8	99,8	99,8	99,8	99,0	99,9	99,5	99,9	H	1
NO_X (g per GJ fuel)	90	67	56	22	11	84	5	56	I	2;3
CH4 (g per GJ fuel)	0,3	0,1	0,1	0,1	0	0,1	0	0,1		2
N2O (g per GJ fuel)	1,2	1	1	1	1	3	0	1	J	2
Particles (g per GJ fuel)	0,3	0,3	0,3	0,3	0,1	2	0,1	1	J	2
Financial data										
Nominal investment (M€/MWe)	10,7	10,5	9,6	8,8	8,9	12,3	6,4	11,0	N	1
- of which equipment	6,7	6,5	6,0	5,6	5,5	7,7	4,0	6,9	N	1
- of which installation	4,1	4,0	3,6	3,2	3,4	4,5	2,4	4,1	M	1
Fixed O&M (€/MWe/year)	427.800	413.600	372.400	329.500	380.500	446.700	276.500	375.600	L	1
Variable O&M (€/MWh_e)	25,6	25,6	24,6	24,4	21,7	29,4	18,3	30,5	K	1
Technology specific data										
Steam reheat	None	None	None	None	None	None	None	None		
Flue gas condensation	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes		
Combustion air humidification	No	No	No	No	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	3,08	2,36	2,25	2,09	2,01	2,77	1,52	2,60	N	1
- of which equipment	1,92	1,47	1,40	1,32	1,25	1,75	0,95	1,64	N	1
- of which installation	1,17	0,89	0,85	0,77	0,76	1,03	0,58	0,96	M	1
Fixed O&M (€/MW input/year)	96.500	93.400	87.400	78.100	79.400	108.500	57.700	97.300	L	1
Variable O&M (€/MWh input)	5,8	5,8	5,8	5,8	4,9	6,6	4,3	7,2	K	1
Nominal investment (€/(tonne/year))	891	869	827	770	739	1.021	561	957	N	1
Fixed O&M (€/tonne)	36	34	32	29	29	40	21	36	L	1;4
Variable O&M (€/tonne)	17	17	17	17	14	20	13	21	K	1;4

Data sheets WtE CHP, medium

Technology	Medium Waste to Energy CHP, Back pressure turbine, 80 MW feed									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	18,4	18,4	18,9	19,5	17,0	20,0	17,0	21,4	A, B	
Incineration capacity (Fuel input) (tonnes/h)	27,2	27,2	27,2	27,2	27,2	27,2	27,2	27,2	A, B	
Electricity efficiency, net (%), name plate	23,0	23,0	23,6	24,4	21	25	21	27	A, B,C	
Electricity efficiency, net (%), annual average	21,9	21,9	22,4	23,2	19	24	19	25	A, B,C	
Heat efficiency, net (%), name plate	78,0	78,0	77,7	77,3	75	83	71	85	A, B	
Heat efficiency, net (%), annual average	79,1	79,1	78,9	78,6	77	84	73	86	A, B, C	
Additional heat potential with heat pumps (% of thermal input)	4,1	4,1	4,0	3,7	2	5	2	5	A, B, D	
Cb coefficient (40°C/80°C)	0,30	0,30	0,30	0,32	0,27	0,32	0,27	0,35	A, B	
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	A, B	
Forced outage (%)	1	1	1	1	1	1	1	1		1
Planned outage (weeks per year)	3,0	2,9	2,6	2,1	2,4	3,3	1,6	2,6	E	1
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	2,5	2,5	2,5	2,5	2,0	3,0	1,5	3,0		1
Space requirement (1000 m2/MWe)	1,6	1,6	1,6	1,5	1,4	1,9	1,2	1,9		1
Primary regulation (% per 30 seconds)	5	5	5	5	5	5	5	5	F	
Secondary regulation (% per minute)	10	10	10	10	10	10	10	10,0	F, G	
Minimum load (% of full load)	20	20	20	20	20	20	20	20,0	F, G	
Warm start-up time (hours)	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	F, G	
Cold start-up time (hours)	2	2	2	2	2	2	2	2	F, G	
Environment										
SO_2 (degree of desulphuring, %)	99,8	99,8	99,8	99,8	99,0	99,9	99,5	99,9	H	1
NO_X (g per GJ fuel)	90	56	45	11	11	84	5	56	I	2;3
CH4 (g per GJ fuel)	0,3	0,1	0,1	0,1	0	0,1	0	0,1		2
N2O (g per GJ fuel)	1,2	1	1	1	1	3	0	1	J	2
Particles (g per GJ fuel)	0,3	0,3	0,3	0,3	0,1	2	0,1	1	J	2
Financial data										
Nominal investment (M€/MWe)	9,3	9,1	8,7	7,6	7,7	10,7	5,5	9,5	N	1
- of which equipment	5,7	5,5	5,4	4,7	4,7	6,6	3,4	5,8	N	1
- of which installation	3,7	3,6	3,3	2,9	3	4,1	2,2	3,6	M	1
Fixed O&M (€/MWe/year)	300.700	264.800	246.700	210.600	244.200	284.600	178.000	239.500	L	1
Variable O&M (€/MWh_e)	25	25	24,5	23,7	21,3	28,8	17,7	29,6	K	1
Technology specific data										

Steam reheat	None	None	None	None	None	None	None	None		
Flue gas condensation	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes		
Combustion air humidification	No	No	No	No	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	2,15	2,10	2,05	1,86	1,78	2,46	1,35	2,31	N	1
- of which equipment	1,31	1,28	1,26	1,15	1,08	1,52	0,82	1,42	N	1
- of which installation	0,84	0,82	0,78	0,71	0,70	0,95	0,53	0,88	M	1
Fixed O&M (€/MW input/year)	69.300	61.000	58.200	51.400	51.900	71.200	37.800	64.000	L	1
Variable O&M (€/MWh input)	5,8	5,8	5,8	5,8	4,9	6,6	4,3	7,2	K	1
Nominal investment (€/(tonne/year))	792	773	753	683	657	907	499	849	N	1
Fixed O&M (€/tonne)	26	22	21	19	19	26	14	24	L	1;4
Variable O&M (€/tonne)	17	17	17	17	14	20	13	21	K	1;4

Data sheets WtE CHP, large

Technology	Large Waste to Energy CHP, Back pressure turbine, 220 MW feed									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	51,2	51,2	52,5	54,4	47,2	55,7	47,2	59,8	A, B	
Incineration capacity (Fuel input) (tonnes/h)	74,7	74,7	74,7	74,7	74,7	74,7	74,7	74,7	A, B	
Electricity efficiency, net (%), name plate	23,3	23,3	23,9	24,7	21	25	21	27	A, B	
Electricity efficiency, net (%), annual average	22,1	22,1	22,7	23,5	19	24	19	26	A, B,C	
Heat efficiency, net (%), name plate	78,1	78,1	77,8	77,4	75	83	71	85	A, B	
Heat efficiency, net (%), annual average	79,3	79,3	79,0	78,7	77	84	73	86	A, B, C	
Additional heat potential with heat pumps (% of thermal input)	4,1	4,1	4,0	3,7	2	5	2	5	A, B, D	
Cb coefficient (40°C/80°C)	0,30	0,30	0,31	0,32	0,27	0,32	0,28	0,35	A, B	
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	A, B	
Forced outage (%)	1	1	1	1	1	1	1	1		1
Planned outage (weeks per year)	2,5	2,4	2,2	1,8	2,0	2,7	1,3	2,2	E	1
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	3,0	3,0	3,0	3,0	2,5	3,5	2,0	3,5		1
Space requirement (1000 m2/MWe)	0,8	0,8	0,8	0,7	0,7	0,9	0,6	0,9		1
Primary regulation (% per 30 seconds)	5	5	5	5	5	5	5	5	F	
Secondary regulation (% per minute)	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	F, G	
Minimum load (% of full load)	20,0	20,0	20,0	20,0	20,0	20,0	20,0	20,0	F, G	
Warm start-up time (hours)	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	F, G	
Cold start-up time (hours)	2	2	2	2	2	2	2	2	F, G	
Environment										
SO_2 (degree of desulphuring, %)	99,8	99,8	99,8	99,8	99,0	99,9	99,5	99,9	H	1

NO_X (g per GJ fuel)	90	56	17	11	11	84	5	56	I	2;3
CH4 (g per GJ fuel)	0,3	0,1	0,1	0,1	0,0	0,1	0,0	0,1		2
N2O (g per GJ fuel)	1,2	1,0	1,0	1,0	1,0	3,0	0,0	1,0	J	2
Particles (g per GJ fuel)	0,3	0,3	0,3	0,3	0,1	2,0	0,1	1,0	J	2
Financial data										
Nominal investment (M€/MWe)	8,0	7,8	7,4	6,5	6,7	9,2	4,8	8,1	N	1
- of which equipment	4,8	4,7	4,6	4,0	4,0	5,6	2,9	5,0	N	1
- of which installation	3,2	3,1	2,9	2,5	2,6	3,6	1,9	3,2	M	1
Fixed O&M (€/MWe/year)	231.700	188.300	175.600	149.600	173.900	202.400	126.500	169.300	L	1
Variable O&M (€/MWh_e)	24,8	24,8	24,2	23,3	21,1	28,5	17,5	29,2	K	1
Technology specific data										
Steam reheat	None	None	None	None	None	None	None	None		
Flue gas condensation	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes		
Combustion air humidification	No	No	No	No	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	1,87	1,83	1,78	1,61	1,55	2,14	1,18	2,00	N	1
- of which equipment	1,13	1,10	1,09	0,99	0,94	1,31	0,71	1,22	N	1
- of which installation	0,74	0,72	0,69	0,62	0,62	0,83	0,47	0,78	M	1
Fixed O&M (€/MW input/year)	54.000	43.900	41.900	37.000	37.300	51.300	27.100	46.000	L	1
Variable O&M (€/MWh input)	5,8	5,8	5,8	5,8	4,9	6,6	4,3	7,2	K	1
Nominal investment (€/(tonne/year))	689	672	654	593	571	788	434	738	N	1
Fixed O&M (€/tonne)	20	16	15	14	14	19	10	17	L	1;4
Variable O&M (€/tonne)	17	17	17	17	14	20	13	21	K	1;4

Notes:

Notes common for all the waste technology data sheets

A Assumed lower heating value 10.6 MJ/kg, waste input 74.7 tph = tonnes per hour (incineration capacity) divided in two, equally sized furnace/boiler units , corresponding to thermal input of 2x110 MW. One common turbine/generator set is foreseen. Live steam pressure in base case 50 bara, temperature 425 °C of 2015 and 2020, increasing to 440 °C and 450 °C, in 2030 and 2050, respectively. Efficiencies refer to lower heating value.

B With flue gas condensation (condensation through heat exchange with DH-water, only) and a back-pressure turbine/condenser system optimised for DH return temperature 40°C and flow 80°C.

C Annual average heat output is higher than nameplate because the total efficiency is constant, and the annual average electricity generation is lower than nameplate electricity output. The parasitic electricity consumption has been subtracted in the listed electricity efficiencies.

D Additional heat potential for heat pump is the flue gas condensation potential remaining after the direct condensation stage (condensation by heat exchange with DH-water).

E Focus on availability and ambitions of 2 years' continuous operation is expected to gradually reduce planned outage.

F Regulation and start-up refer to electricity generation controlled by the turbine operation.The WtE facility would usually be operating at 100% thermal input, and the electricity output is controlled to the desired level by use of turbine by-pass, by which excess steam is used to produce DH-energy. Warm start-up time refers to 2 days down-time of the turbine.

G The combustion process and boiler may be regulated approx. 1% per minute considering extensive use of inconell (in stead of refractory, which may limit rate of change to 0.5% per minute). Minimum load is typically 70% of thermal input under which limit it may be difficult to comply with the requirement of min. 2 sec residence time of the flue gas at min. 850 °C after the last air injection. Below this limit it may also be a challenge to ensure sufficient superheating of the steam. Warm start-up of the combustion process is typically 8 hours and cold start-up is 8 hours.

H Assumed low SO2-emission 1 g/GJ in 2015 considering the use of flue gas condensation by wet scrubbing down-stream the flue gas treatment system. Sulphur content in fuel 270 g/GJ.

I Increased focus on NOx reduction is expected in the future, requiring use of SNCR technology to its utmost potential by 2030 (at 60 g/GJ) and use of the more effective catalytic SCR-technology by 2050. The SCR-technology entails additional investment.

J N2O is expected to be related primarily to the use of SNCR. This is why little N2O is expected when the SCR-deNOx technology is used (indicated by verly low NOx-level).

K Variable O&M cost includes consumables (for FGT etc.), disposal of residues, small share of staff-cost and maintenance cost. Electricity consumption is not included, and revenues from sale of electricity and heat are not included. Taxes are not included.

L Fixed O&M include amongst other things the major part of staffing and maintenance, analyses, research and development, accounting, insurances, fees, memberships, office. Not included are finance cost, depreciation and amortisation.

M Installation includes civils works (including waste bunker) and project cost considering LOT-based tendering.

N Assuming LOT-based tendering of electromechanic equipment.

References

References common for all the waste technology data sheet

1 Rambøll present work, range of WtE-projects

2 Emission factors of 2006: 102 g/GJ NOx, <8,3 g/GJ for SO2, <0,34 g/GJ for CH4, 1,2 g/GJ for N2O, cf.

Nielsen, M., Nielsen, O.-K. & Thomsen, M. 2010: Emissions from decentralised CHP plants 2007 - Energinet.dk Environmental project no. 07/1882. Project report 5 – Emission factors and emission inventory for decentralised CHP production. National Environmental Research Institute, Aarhus University. 113 pp. – NERI Technical report No. 786.

http://www.dmu.dk/Pub/FR786.pdf.

3 Environmental permit of recently constructed WtE-facility includes NOx limit value of 180 mg/Nm³ =100 g/GJ. Operation is expected well below limit value. Cf. Miljøstyrelsen, "Tillæg til miljøgodkendelse, Ny ovnlinje 5 på Nordforbrænding, Juni 2013," http://mst.dk/media/mst/Attachments/Tillgtilmiljgodkendelseovn5Juni2013.pdf

4 To scenarier for tilpasning af affaldsforbrændingskapaciteten i Danmark. EA Energianalyse 2014.

09 Biomass CHP, steam turbine, large, medium and small (updated datasheet available)

For technical descriptions of the technologies go to previous catalogue. In this catalogue a common qualitative description of the the technology sheets of biomass and waste fired plants (chapter 08, 09, 42 and 43) are presented in chapter 99 in this publication.

The specific chapter for *Biomass CHP, steam turbine* is under review. The old version (2012/2015) is found in the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

Data sheets Wood Chips CHP, small

Technology	Small Wood Chips CHP, 20 MW feed									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	2,9	2,9	2,9	2,8	2,8	2,9	2,7	2,9	A	
Electricity efficiency, net (%), name plate	14,3	14,3	14,3	14,0	14	14	14	14	A, H	1
Electricity efficiency, net (%), annual average	13,5	13,5	13,6	13,3	13	14	12	14	A, H	1
Heat efficiency, net (%), name plate	97,3	97,3	97,3	97,6	71	98	69	98	B, H	1
Heat efficiency, net (%), annual average	98,1	98,1	98,0	98,3	72	98	71	99	B, H	1
Additional heat potential with heat pumps (% of thermal input)	2,0	2,0	2,0	2,0	2	28	2	30	C	1
Cb coefficient (40°C/80°C)	0,15	0,15	0,15	0,14	0,14	0,15	0,14	0,15		
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	I	
Forced outage (%)	3	3	3	3	3	3	3	3		
Planned outage (weeks per year)	3,0	3,0	3,0	3,0	2,6	3,5	2,3	3,8		
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	1	1	1	1	0,5	1,5	0,5	1,5		1
Space requirement (1000 m2/MWe)	0,7	0,7	0,7	0,7	0,6	0,8	0,5	0,9		
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA		
Secondary regulation (% per minute)	10	10	10	10	10	10	10	10	D	1
Minimum load (% of full load)	20	20	20	20	20	20	20	20	D	1
Warm start-up time (hours)	0,25	0,25	0,25	0,25	0,25	0,25	0,25	0,25	G	1
Cold start-up time (hours)	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5		1
Environment										
SO_2 (degree of desulphuring, %)	98,0	98,0	98,0	98,0	94,9	99,0	98,0	99,0	F	1
NO_X (g per GJ fuel)	90	63	41	32	41	81	20	41	F	1
CH4 (g per GJ fuel)	16	11	8	4	4	16	2	16	F	1
N2O (g per GJ fuel)	1	1	1	1	1	3	0	1	F	1
Particles (g per GJ fuel)	2,0	0,3	0,3	0,3	0,1	2,0	0,1	1,0	F	1
Financial data										
Nominal investment (M€/MWe)	6,7	6,5	6,2	6,0	5,7	7,7	4,7	8,1	E, J, K	1
- of which equipment	4,1	4,0	3,8	3,8	3,5	4,8	2,9	5,2	K	
- of which installation	2,5	2,5	2,3	2,2	2,1	2,9	1,8	3,0	K	
Fixed O&M (€/MWe/year)	292.700	288.900	280.500	277.900	252.000	331.000	215.600	347.000		
Variable O&M (€/MWh_e)	7,8	7,8	7,7	7,9	6,6	8,9	5,9	9,8		
Technology specific data										
Steam reheat	None	None	None	None	None	None	None	None		
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes		

Nominal investment (M€/MW fuel input)	0,95	0,93	0,88	0,84	0,81	1,09	0,66	1,14	J, K	1
- of which equipment	0,59	0,58	0,55	0,53	0,50	0,68	0,41	0,72	K	
- of which installation	0,36	0,35	0,33	0,30	0,31	0,41	0,25	0,42	K	
Fixed O&M (€/MW input/year)	41.800	41.200	40.200	39.000	35.300	47.800	29.600	50.100		
Variable O&M (€/MWh input)	1,1	1,1	1,1	1,1	0,9	1,3	0,8	1,4		
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,020	0,020	0,019	0,017	0,017	0,023	0,014	0,023	K	

Notes:

A The plant is directly producing hot water for District Heating by burning fuel on a grate. The electric power is produced by an ORC module (Organic Rankine Cycle; Waste Heat Recovery - WHR). Refer for instance to the following link for further information about technology and suppliers: http://www.enova.no/upload_images/36AC689098414B05A7112FA2EE985BDA.pdf . This is low temperature and low efficiency electric power but at an affordable price.

B Boilers up to 20 MW fuel input for hot water production are more or less standardized products with a high degree of fuel flexibility (type of biomass, humidity etc.)

C There are plants of this type with up to 110 % efficiency using flue gas condensation with moist wood chips and close to 120 % efficiency with both flue gas condensation and absorption heat pumps activated. The colder the return temperature of the district heating, the higher the total efficiencyat direct condensation. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.
Secondary regulation normally relates to power production; for this type of plant it may not be of importance. Though, the load control of the heat production is important and most units will perform better than the figure shown. Also, minimum load could be substantially lower.

E Since electricity generation is only a secondary objective for minor heat producers, it may make more sense to relate the total investment only to the heat production capacity.

F It is to be expected that necessary DeNOx can be accomplished using SNCR, except where anticipated emission levels are below 40 g/GJ

G Warm start is starting with a glowing fuel layer on the grate.

H The total efficiency is the sum of electricity efficiency and heat efficiency, applicable for "name plate" and "annual average", respectively. The "annual average" electricity efficiency is lower than "name plate" due to turbine outages and other incidents. The resulting lost power production is recovered as heat. This is why "annual average" heat efficiency is higher than "name plate" heat. Efficiencies refer to lower heating value. The parasitic electricity consumption has been subtracted in the listed electricity efficiencies.

I Cv=1 describes turbine by-pass operation. During operation the turbine can be by-passed fully or partly for direct district heating production, at operator choice.

J Investment applies to a standard plant. There could be cost related to the actual project or site that adds to the total investment, e.g. additional fuel storage, facilities for chipping of logs, conditions for foundation and harbour facilities.
Financial data and Technological specific data are essentially the total cost either divided by the electric net capacity, i.e. corresponding to the indicated name plate efficiencies, or by the thermal input. This is to indicate that new plants may not fully take advantage of the technical capabilities for full electricity production capacity. The two cost for electricity and thermal input, respectively, are not to be added up!

K Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal model and evaluation based on either existing projects, supplier offers, or pre-project studies.

Data sheets Wood Chips CHP, medium

Technology	Medium Wood Chips CHP, 80 MW feed									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		

Generating capacity for one unit (MWe)	23,1	23,1	23,2	22,8	21,8	30,9	22,4	31,8	A	
Electricity efficiency, net (%), name plate	28,9	28,9	29,0	28,5	27	39	28	40	A, H, F	1
Electricity efficiency, net (%), annual average	27,4	27,4	27,5	27,0	25	37	25	38	A, H, F	1
Heat efficiency, net (%), name plate	82,1	82,1	81,9	82,5	46	84	43	83	B, H	1
Heat efficiency, net (%), annual average	83,5	83,5	83,4	83,9	49	86	46	85	B, H	1
Additional heat potential with heat pumps (% of thermal input)	2,0	2,0	2,0	2,0	2	28	2	30	C	1
Cb coefficient (40°C/80°C)	0,35	0,35	0,35	0,35	0,33	0,47	0,34	0,48		
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	I	
Forced outage (%)	3	3	3	3	3	3	3	3		
Planned outage (weeks per year)	3,0	3,0	3,0	3,0	2,6	3,5	2,3	3,8		
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	2,5	2,5	2,5	2,5	2	3	1,5	3		1
Space requirement (1000 m2/MWe)	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,3		
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA		
Secondary regulation (% per minute)	4	4	4	4	4	4	4	4	D	1
Minimum load (% of full load)	20	20	20	20	20	20	20	20		
Warm start-up time (hours)	2	2	2	2	2	2	2	2	E+G	1
Cold start-up time (hours)	8	8	8	8	8	8	8	8		1
Environment										
SO_2 (degree of desulphuring, %)	98,0	98,0	98,0	98,0	94,9	99,0	98,0	99,0	F	1
NO_X (g per GJ fuel)	90	72	41	24	41	81	20	41	F	1
CH4 (g per GJ fuel)	3	2	2	1	1	3	0	3	F	1
N2O (g per GJ fuel)	1	1	1	1	1	3	0	1	F	1
Particles (g per GJ fuel)	2,0	0,3	0,3	0,3	0,1	2,0	0,1	1,0	F	1
Financial data										
Nominal investment (M€/MWe)	3,7	3,6	3,5	3,3	3,1	4,3	2,5	4,5	J, K	1
- of which equipment	2,5	2,4	2,3	2,2	2,0	2,9	1,7	3,0	K	
- of which installation	1,2	1,2	1,1	1,1	1,0	1,4	0,9	1,5	K	
Fixed O&M (€/MWe/year)	158.400	153.600	144.000	132.800	133.400	137.000	101.400	123.000		
Variable O&M (€/MWh_e)	3,8	3,8	3,8	3,9	3,3	4,4	2,9	4,9		
Technology specific data										
Steam reheat	None	None	None	None	None	Yes	None	Yes		
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	1,08	1,05	1,00	0,94	0,88	1,24	0,72	1,28	J, K	1
- of which equipment	0,72	0,71	0,67	0,64	0,58	0,83	0,47	0,87	K	
- of which installation	0,36	0,35	0,33	0,30	0,30	0,41	0,25	0,41	K	
Fixed O&M (€/MW	45.800	44.369	41.766	37.793	37.323	51.473	28.349	48.834		

input/year)										
Variable O&M (€/MWh input)	1,1	1,1	1,1	1,1	0,9	1,3	0,8	1,4		
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,015	0,015	0,014	0,013	0,013	0,017	0,010	0,017	K	

Notes:

A The boiler in the plant is a grate fired boiler producing steam to be used in a subsequent back pressure steam turbine. Though a grate is reasonable flexible with respect to combusting different fuels the fuel feed system will be dependent on the type of fuel. It is to be expected that it is necessary with a specific DeNOx plant (SNCR might not be sufficient).

B Through a turbine by-pass all the produced steam energy is used for District Heat production.

C Plants of this type may achieve up to 110 % efficiency using flue gas condensation with moist wood chips and 115 % efficiency with both flue gas condensation and absorption heat pumps activated. The colder the return temperature of the district heating, the higher the total efficiency at direct condensation. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.

D Secondary regulation normally relates to power production; for this type of plant it may not be of importance since load will normally follow heat consumption.

E A limiting factor for the hot and cold start-up times is the size of the hot water tank (deaerator).

F It is to be expected that necessary DeNOx can be accomplished using SNCR, except where anticipated emission levels are below 40 g/GJ in which case SCR is used with slight adverse effect on electricity efficiency.

G Warm start is starting with a glowing fuel layer on the grate and a warm deaerator.

H The total efficiency is the sum of electricity efficiency and heat efficiency, applicable for "name plate" and "annual average", respectively. The "annual average" electricity efficiency is lower than "name plate" due to turbine outages and other incidents. The resulting lost power production is recovered as heat. This is why "annual average" heat efficiency is higher than "name plate" heat. Efficiencies refer to lower heating value. The parasitic electricity consumption has been subtracted in the listed electricity efficiencies.

I The Cv value does not exist for plants with a back pressure turbine or an ORC turbine

J Investment applies to a standard plant. There could be cost related to the actual project or site that adds to the total investment, e.g. additional fuel storage, facilities for chipping of logs, conditions for foundation and harbour facilities.
Financial data and Technological specific data are essentially the total cost either divided by the electric net capacity, i.e. corresponding to the indicated name plate efficiencies, or by the thermal input. This is to indicate that new plants may not fully take advantage of the technical capabilities for full electricity production capacity. The two cost for electricity and thermal input, respectively, are not to be added up!

K Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies.

Data sheets Wood Chips CHP, large

Technology	Large Wood Chips CHP, 600 MW feed									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	176,5	176,9	177,5	174,4	162,9	235,0	170,9	242,6	A	
Electricity efficiency, net (%), name plate	29,4	29,5	29,6	29,1	27	39	28	40	A, H	1
Electricity efficiency, net (%), annual average	27,9	28,0	28,1	27,6	24	37	26	38	A, H	1

Heat efficiency, net (%), name plate	82,0	82,2	82,0	82,6	45	84	43	83	B, H	1
Heat efficiency, net (%), annual average	83,5	83,6	83,5	84,0	47	86	46	85	B, H	1
Additional heat potential with heat pumps (% of thermal input)	2,0	1,9	1,9	1,9	2	30	2	30	C	1
Cb coefficient (40°C/80°C)	0,36	0,36	0,36	0,35	0,33	0,48	0,34	0,49		
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1		
Forced outage (%)	3	3	3	3	3	3	3	3		
Planned outage (weeks per year)	3,0	3,0	3,0	3,0	2,6	3,5	2,3	3,8		
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	5	5	5	5	4,5	5,5	4	5,5		1
Space requirement (1000 m2/MWe)	0,08	0,08	0,08	0,09	0,07	0,10	0,06	0,11		1
Primary regulation (% per 30 seconds)	2	2	2	2	2	2	2	2		
Secondary regulation (% per minute)	4	4	4	4	4	4	4	4	D	1
Minimum load (% of full load)	45	45	45	45	45	45	45	45		
Warm start-up time (hours)	2	2	2	2	2	2	2	2	E+G	1
Cold start-up time (hours)	12	12	12	12	12	12	12	12		1
Environment										
SO_2 (degree of desulphuring, %)	98,0	98,0	98,0	98,0	94,9	99,0	98,0	99,0	F	1
NO_X (g per GJ fuel)	30	24	20	12	12	30	8	20	F	1
CH4 (g per GJ fuel)	3	2	2	1	1	3	0	3	F	1
N2O (g per GJ fuel)	10	8	6	5	5	10	3	10	F	1
Particles (g per GJ fuel)	0,3	0,3	0,3	0,3	0,1	2,0	0,1	1,0	F	1
Financial data										
Nominal investment (M€/MWe)	3,5	3,4	3,2	3,0	2,9	4,1	2,4	4,2	J, K	1
- of which equipment	2,3	2,2	2,1	2,0	1,8	2,7	1,5	2,7	K	
- of which installation	1,2	1,2	1,1	1,0	1,0	1,4	0,9	1,4	K	
Fixed O&M (€/MWe/year)	100.500	97.600	92.300	86.300	86.600	89.600	67.200	81.300		
Variable O&M (€/MWh_e)	3,8	3,8	3,7	3,8	3,2	4,3	2,9	4,8		
Technology specific data										
Steam reheat	None	None	None	None	None	Yes	None	Yes		
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	1,03	1,00	0,95	0,88	0,85	1,20	0,70	1,21	J, K	1
- of which equipment	0,66	0,65	0,62	0,58	0,54	0,78	0,44	0,79	K	
- of which installation	0,36	0,35	0,34	0,30	0,31	0,42	0,25	0,42	K	
Fixed O&M (€/MW input/year)	29.500	28.800	27.300	25.100	24.300	33.900	19.100	32.900		
Variable O&M (€/MWh input)	1,1	1,1	1,1	1,1	0,9	1,3	0,8	1,4		
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,010	0,010	0,009	0,008	0,009	0,012	0,007	0,012	K	

Notes:

A The boiler in the plant is a circulating fluid bed boiler (CFB) producing steam to be used in a subsequent extraction steam turbine without steam re-heat.

B Through a turbine by-pass all the produced steam energy can be used for District Heat production.

C Plants of this type may achieve up to 110 % efficiency using flue gas condensation with moist wood chips and 115 % efficiency with both flue gas condensation and absorption heat pumps activated. The colder the return temperature of the district heating, the higher the total efficiency at direct condensation. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.

D Secondary regulation normally relates to power production; for this type of plant it may not be of importance since load will normally follow heat consumption.

E A limiting factor for the hot and cold start-up times is the size of the hot water tank (deaerator). Warm start-up time is particularly low for fluid bed types of plants.

F It is to be expected that the NOx level is low from the CFB, and that the necessary DeNOx can be accomplished using SNCR, except where anticipated emission levels are below 20 g/GJ, in which case SCR is used.

G Warm start is starting with a glowing bed and a warm deaerator.

H The total efficiency is the sum of electricity efficiency and heat efficiency, applicable for "name plate" and "annual average", respectively. The "annual average" electricity efficiency is lower than "name plate" due to turbine outages and other incidents. The resulting lost power production is recovered as heat. This is why "annual average" heat efficiency is higher than "name plate" heat. Efficiencies refer to lower heating value. The parasitic electricity consumption has been subtracted in the listed electricity efficiencies.

I Financial data and Technological specific data are essentially the total cost either divided by the electric net capacity or by the net heat capacity, i.e. corresponding to the indicated name plate efficiencies. This is to indicate that new plants may not fully take advantage of the technical capabilities for either full electricity production capacity or heat production capacity. The two cost for electricity and heat, respectively, are not to be added up!

J Investment applies to a standard plant. There could be cost related to the actual project or site that adds to the total investment, e.g. additional fuel storage, facilities for chipping of logs, conditions for foundation and harbour facilities.
Financial data and Technological specific data are essentially the total cost either divided by the electric net capacity, i.e. corresponding to the indicated name plate efficiencies, or by the thermal input. This is to indicate that new plants may not fully take advantage of the technical capabilities for full electricity production capacity. The two cost for electricity and thermal input, respectively, are not to be added up!

K Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies.

Data sheets Wood Pellets CHP, small

Technology	Small Wood Pellets CHP, 20 MW feed									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	3,0	3,0	3,0	3,0	2,9	3,0	2,9	3,0	A	
Electricity efficiency, net (%), name plate	15,1	15,1	14,9	14,9	15	15	15	15	A, H	1
Electricity efficiency, net (%), annual average	14,4	14,4	14,2	14,2	13	14	13	14	A, H	1
Heat efficiency, net (%), name plate	82,2	82,2	82,4	82,4	71	83	72	83	B, H	1
Heat efficiency, net (%), annual average	83,0	83,0	83,1	83,1	73	84	73	84	B, H	1
Additional heat potential with heat pumps (% of thermal input)	1,7	1,7	1,7	1,7	2	12	2	12	C	1

Cb coefficient (40°C/80°C)	0,18	0,18	0,18	0,18	0,18	0,19	0,18	0,18		
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	I	
Forced outage (%)	3	3	3	3	3	3	3	3		
Planned outage (weeks per year)	3,0	3,0	3,0	3,0	2,6	3,5	2,3	3,8		
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	1	1	1	1	0,5	1,5	0,5	1,5		1
Space requirement (1000 m2/MWe)	0,5	0,5	0,5	0,5	0,4	0,6	0,4	0,6		
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA		
Secondary regulation (% per minute)	10	10	10	10	10	10	10	10	D	1
Minimum load (% of full load)	20	20	20	20	20	20	20	20	D	1
Warm start-up time (hours)	0,25	0,25	0,25	0,25	0,25	0,25	0,25	0,25	G	1
Cold start-up time (hours)	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5		1
Environment										
SO_2 (degree of desulphuring, %)	98,3	98,3	98,3	98,3	95,6	99,1	98,3	99,1	F	1
NO_X (g per GJ fuel)	90	54	35	28	35	70	18	35	F	1
CH4 (g per GJ fuel)	0	0	0	0	0	0	0	0	F	1
N2O (g per GJ fuel)	1	1	1	1	1	3	0	1	F	1
Particles (g per GJ fuel)	2,0	0,3	0,3	0,3	0,1	2,0	0,1	1,0	F	1
Financial data										
Nominal investment (M€/MWe)	6,3	6,2	6,2	5,6	5,4	7,6	4,7	7,7	E,J,K	1
- of which equipment	4,1	4,0	4,1	3,8	3,5	5,0	3,2	5,1	K	
- of which installation	2,2	2,1	2,1	1,9	1,9	2,5	1,6	2,6	K	
Fixed O&M (€/MWe/year)	280.900	275.900	274.800	257.800	243.500	322.400	204.700	329.400		
Variable O&M (€/MWh_e)	3,4	3,4	3,4	3,4	2,9	3,9	2,6	4,3		
Technology specific data										
Steam reheat	None	None	None	None	None	None	None	None		
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	0,96	0,93	0,93	0,84	0,81	1,14	0,71	1,15	E,J,K	1
- of which equipment	0,63	0,61	0,62	0,56	0,53	0,76	0,47	0,76	K	
- of which installation	0,33	0,32	0,31	0,28	0,28	0,38	0,23	0,39	K	
Fixed O&M (€/MW input/year)	42.500	41.700	41.100	38.500	35.700	49.100	30.000	49.500		
Variable O&M (€/MWh input)	0,51	0,51	0,51	0,51	0,43	0,59	0,38	0,64		
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,004	0,004	0,004	0,003	0,003	0,005	0,003	0,005	K	

Notes:

A The plant is directly producing hot water for District Heating by burning fuel on a grate. The electric power is produced by an ORC module (Organic Rankine Cycle; Waste Heat Recovery - WHR). Refer for instance to the following link for further information about technology and suppliers: http://www.enova.no/upload_images/36AC689098414B05A7112FA2EE985BDA.pdf . This is low temperature and low efficiency electric power but at an affordable price.

B Boilers up to 20 MW fuel input for hot water production are more or less standardized products with a high degree of fuel flexibility (type of biomass, humidity etc.)
C There are plants of this type with up to 110 % efficiency using flue gas condensation with moist wood chips and close to 120 % efficiency with both flue gas condensation and absorption heat pumps activated. The colder the return temperature of the district heating, the higher the total efficiency at direct condensation. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.
D Secondary regulation normally relates to power production; for this type of plant it may not be of importance. Though, the load control of the heat production is important and most units will perform better than the figure shown. Also, minimum load could be substantially lower.
E Since electricity generation is only a secondary objective for minor heat producers, it may make more sense to relate the total investment only to the thermail input.
F It is anticipated that for the smaller units the supplier has a SNCR solutiuon to avoid NOx emissions sufficiently. Little SO2, CH4 and N2O are emitted when combusting wooddy biomass.
G Warm start is starting with a glowing fuel layer on the grate.
H The total efficiency is the sum of electricity efficiency and heat efficiency, applicable for "name plate" and "annual average", respectively. The "annual average" electricity efficiency is lower than "name plate" due to turbine outages and other incidents. The resulting lost power production is recovered as heat. This is why "annual average" heat efficiency is higher than "name plate" heat. Efficiencies refer to lower heating value. The parasitic electricity consumption has been subtracted in the listed electricity efficiencies.
I The Cv value does not exist for plants with a back pressure turbine or an ORC turbine
J Investment applies to a standard plant. There could be cost related to the actual project or site that adds to the total investment, e.g. additional fuel storage, facilities for chipping of logs, conditions for foundation and harbour facilities.
Financial data and Technological specific data are essentially the total cost either divided by the electric net capacity, i.e. corresponding to the indicated name plate efficiencies, or by the thermal input. This is to indicate that new plants may not fully take advantage of the technical capabilities for full electricity production capacity. The two cost for electricity and thermal input, respectively, are not to be added up!
K Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies.

Data sheets Wood Pellets CHP, medium

Technology	Medium Wood Pellets CHP, 80 MW feed									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	24,1	24,1	23,9	23,9	23,2	32,5	23,5	32,7	A	
Electricity efficiency, net (%), name plate	30,2	30,2	29,8	29,8	29	41	29	41	A, H, F	1
Electricity efficiency, net (%), annual average	28,6	28,6	28,3	28,3	26	39	26	39	A, H, F	1
Heat efficiency, net (%), name plate	66,5	66,5	66,8	66,8	44	69	44	68	A, H, F	1
Heat efficiency, net (%), annual average	68,0	68,0	68,3	68,3	47	71	47	70	B, H	1
Additional heat potential with heat pumps (% of thermal input)	1,7	1,7	1,7	1,7	2	12	2	12	C	1
Cb coefficient (40°C/80°C)	0,45	0,45	0,45	0,45	0,44	0,61	0,44	0,61		
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	I	
Forced outage (%)	3	3	3	3	3	3	3	3		
Planned outage (weeks per year)	3,0	3,0	3,0	3,0	2,6	3,5	2,3	3,8		
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	1	1	1	1	0,5	1,5	0,5	1,5		1

Space requirement (1000 m2/MWe)	0,2	0,2	0,2	0,2	0,2	0,2	0,1	0,2		
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA		
Secondary regulation (% per minute)	10	10	10	10	10	10	10	10	D	1
Minimum load (% of full load)	15	15	15	15	15	15	15	15		
Warm start-up time (hours)	0,25	0,25	0,25	0,25	0,25	0,25	0,25	0,25	E	1
Cold start-up time (hours)	8	8	8	8	8	8	8	8		1
Environment										
SO_2 (degree of desulphuring, %)	98,3	98,3	98,3	98,3	95,6	99,1	98,3	99,1	F	1
NO_X (g per GJ fuel)	78	62	35	21	35	70	18	35	F	1
CH4 (g per GJ fuel)	0	0	0	0	0	0	0	0	F	1
N2O (g per GJ fuel)	1	1	1	1	1	3	0	1	F	1
Particles (g per GJ fuel)	2,0	0,3	0,3	0,3	0,1	2,0	0,1	1,0	F	1
Financial data										
Nominal investment (M€/MWe)	3,2	3,1	3,1	2,8	2,6	3,7	2,2	3,8	J,K	1
- of which equipment	2,0	2,0	2,0	1,8	1,6	2,4	1,4	2,5	K	
- of which installation	1,1	1,1	1,1	1,0	1,0	1,3	0,8	1,3	K	
Fixed O&M (€/MWe/year)	130.800	127.100	123.300	110.800	110.600	110.700	85.800	104.200		
Variable O&M (€/MWh_e)	1,7	1,7	1,7	1,7	1,4	1,9	1,3	2,1		
Technology specific data										
Steam reheat	None	None	None	None	None	Yes	None	Yes		
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	0,95	0,93	0,91	0,83	0,77	1,12	0,66	1,13	J,K	1
- of which equipment	0,61	0,59	0,59	0,54	0,48	0,73	0,42	0,73	K	
- of which installation	0,34	0,33	0,32	0,29	0,29	0,40	0,24	0,40	K	
Fixed O&M (€/MW input/year)	39.500	38.300	36.800	33.100	32.100	45.000	25.200	42.700		
Variable O&M (€/MWh input)	0,51	0,51	0,51	0,51	0,43	0,59	0,38	0,64		
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,003	0,003	0,003	0,003	0,003	0,003	0,002	0,003	K	

Notes:

A The boiler in the plant is a suspension fired boiler producing steam to be used in a subsequent back pressure steam turbine. It is possible to pulverize wood pellets and use it for suspension firing but it has not been possible to find an appropriate reference.

B Through a turbine by-pass all the produced steam energy is used for District Heat production.

C Since wood pellets are relatively dry there is often only a minor efficiency advantage in using flue gas condensation. There is though an environmental advantage in having a scrubber in the flue gas stream. Direct condensation is assumed in all cases. Combustion air humidification is included except in lower range of 2020 and 2050. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.

D Secondary regulation normally relates to power production; for this type of plant it may not be of importance since load will normally follow heat consumption.

E A limiting factor for the hot and cold start-up times is the size of the hot water tank (deaerator).

F SNCR is assumed at NOx emissions at no less than 40 g/GJ. At lower NOx-levels it is chosen to include a tail-end SCR catalyst with slight adverse effect on electricity efficiency.
G Warm start is starting with a glowing fuel layer on the grate and a warm deaerator.
H The total efficiency is the sum of electricity efficiency and heat efficiency, applicable for "name plate" and "annual average", respectively. The "annual average" electricity efficiency is lower than "name plate" due to turbine outages and other incidents. The resulting lost power production is recovered as heat. This is why "annual average" heat efficiency is higher than "name plate" heat. Efficiencies refer to lower heating value. The parasitic electricity consumption has been subtracted in the listed electricity efficiencies.
I The Cv value does not exist for plants with a back pressure turbine or an ORC turbine
J Investment applies to a standard plant. There could be cost related to the actual project or site that adds to the total investment, e.g. additional fuel storage, facilities for chipping of logs, conditions for foundation and harbour facilities.
Financial data and Technological specific data are essentially the total cost either divided by the electric net capacity, i.e. corresponding to the indicated name plate efficiencies, or by the thermal input. This is to indicate that new plants may not fully take advantage of the technical capabilities for full electricity production capacity. The two cost for electricity and thermal input, respectively, are not to be added up!
K Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies.

Data sheets Wood Pellets CHP, large

Technology	**Large Wood Pellets CHP, 800 MW feed**									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	260,6	261,2	261,9	261,9	258,5	338,5	258,5	338,5	A	
Electricity efficiency, net (%), name plate	32,6	32,6	32,7	32,7	32	42	32	42	A, H	1
Electricity efficiency, net (%), annual average	30,9	31,0	31,1	31,1	29	40	29	40	A, H	1
Heat efficiency, net (%), name plate	63,8	63,9	63,8	63,8	43	64	43	64	B, H	1
Heat efficiency, net (%), annual average	65,4	65,5	65,4	65,4	47	66	47	66	B, H	1
Additional heat potential with heat pumps (% of thermal input)	1,7	1,7	1,7	1,7	2	12	2	12	C	1
Cb coefficient (40°C/80°C)	0,51	0,51	0,51	0,51	0,51	0,66	0,51	0,66		
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	I	
Forced outage (%)	3	3	3	3	3	3	3	3		
Planned outage (weeks per year)	3,0	3,0	3,0	3,0	2,6	3,5	2,3	3,8		
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	1	1	1	1	0,5	1,5	0,5	1,5		1
Space requirement (1000 m2/MWe)	0,1	0,1	0,1	0,1	0,1	0,1	0,0	0,1		
Primary regulation (% per 30 seconds)	2	2	2	2	2	2	2	2		
Secondary regulation (% per minute)	4	4	4	4	4	4	4	4	D	1
Minimum load (% of full load)	15	15	15	15	15	15	15	15		1
Warm start-up time (hours)	2	2	2	2	2	2	2	2	G	1
Cold start-up time (hours)	12	12	12	12	12	12	12	12	E	1
Environment										

SO_2 (degree of desulphuring, %)	98,3	98,3	98,3	98,3	95,6	99,1	98,3	99,1		1
NO_X (g per GJ fuel)	20	21	18	11	11	26	7	18	C+F	
CH4 (g per GJ fuel)	0	0	0	0	0	0	0	0		
N2O (g per GJ fuel)	1	1	1	1	1	3	0	1		
Particles (g per GJ fuel)	0,3	0,3	0,3	0,3	0,1	2,0	0,1	1,0		
Financial data										
Nominal investment (M€/MWe)	2,4	2,3	2,2	2,0	2,0	2,7	1,6	2,7	J,K	1
- of which equipment	1,3	1,3	1,2	1,1	1,1	1,5	0,9	1,5	K	
- of which installation	1,0	1,0	1,0	0,9	0,9	1,2	0,7	1,2	K	
Fixed O&M (€/MWe/year)	65.700	64.000	61.000	55.900	54.500	57.300	43.800	56.400		
Variable O&M (€/MWh_e)	1,6	1,6	1,6	1,6	1,3	1,8	1,2	1,9		
Technology specific data										
Steam reheat	None	None	None	None	None	Yes	None	Yes		
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	0,77	0,75	0,72	0,65	0,64	0,89	0,53	0,89	J,K	1
- of which equipment	0,43	0,42	0,40	0,36	0,35	0,49	0,29	0,50	K	
- of which installation	0,34	0,33	0,32	0,29	0,29	0,39	0,24	0,40	K	
Fixed O&M (€/MW input/year)	21.400	20.900	20.000	18.300	17.600	24.300	14.100	23.900		
Variable O&M (€/MWh input)	0,51	0,51	0,51	0,51	0,43	0,59	0,38	0,64		
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,003	0,002	0,002	0,002	0,002	0,003	0,002	0,003	K	

Notes:

A The boiler in the plant is a suspension fired boiler producing steam to be used in a subsequent steam turbine. Currently, the steam turbine is expected to be an extraction turbine with no re-heat. In some of the future scenarios it is assumed that the prices on electricity will allow for an increased electrical efficiency and subsequently re-heating of steam is introduced.

B Through a turbine by-pass all the produced steam energy can be used for District Heat production.

C Since wood pellets are relatively dry there is often only a minor efficiency advantage in using flue gas condensation. There is though an environmental advantage in having a scrubber in the flue gas stream. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.

D This is given by grid code (Energinet.dk)

E A limiting factor for the hot and cold start-up times is the size of the hot water tank (deaerator).

F This plant is equiped with an SCR catalyst for DeNOx and an electrostatic precipitator for catching dust/fly ash

G Warm start is starting with the steam system being pressurized.

H The total efficiency is the sum of electricity efficiency and heat efficiency, applicable for "name plate" and "annual average", respectively. The "annual average" electricity efficiency is lower than "name plate" due to turbine outages and other incidents. The resulting lost power production is recovered as heat. This is why "annual average" heat efficiency is higher than "name plate" heat. Efficiencies refer to lower heating value. The parasitic electricity consumption has been subtracted in the listed electricity efficiencies.

I The Cv value may vary according to the optimization of the plant. A modest value representing a choice with current power/heat prices is shown but an approximate BAT value is given as 'UPPER'

J Investment applies to a standard plant. There could be cost related to the actual project or site that adds to the total investment, e.g. additional fuel storage, facilities for chipping of logs, conditions for foundation and harbour facilities.
Financial data and Technological specific data are essentially the total cost either divided by the electric net capacity, i.e. corresponding to the indicated name plate efficiencies, or by the thermal input. This is to indicate

that new plants may not fully take advantage of the technical capabilities for full electricity production capacity. The two cost for electricity and thermal input, respectively, are not to be added up!

K Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies.

Data sheets Straw CHP, small

Technology	Small Straw CHP, 20 MW feed									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	3,0	3,0	3,0	3,0	3,0	3,0	2,9	3,0	A	
Electricity efficiency, net (%), name plate	15,0	15,0	15,0	14,8	15	15	15	15	A, H	1
Electricity efficiency, net (%), annual average	14,2	14,2	14,3	14,1	13	14	13	14	A, H	1
Heat efficiency, net (%), name plate	84,2	84,2	84,2	84,4	72	85	71	85	B, H	1
Heat efficiency, net (%), annual average	85,0	85,0	84,9	85,1	74	85	73	86	B, H	1
Additional heat potential with heat pumps (% of thermal input)	1,7	1,7	1,7	1,7	2	13	2	14	C	1
Cb coefficient (40°C/80°C)	0,18	0,18	0,18	0,18	0,18	0,18	0,17	0,18		
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	I	
Forced outage (%)	4	4	4	4	4	4	4	4		
Planned outage (weeks per year)	4,0	4,0	4,0	4,0	3,4	4,6	3,0	5,0		
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	1	1	1	1	0,5	1,5	0,5	1,5		1
Space requirement (1000 m2/MWe)	1,0	1,0	1,0	1,0	0,9	1,2	0,8	1,3		
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA		
Secondary regulation (% per minute)	10	10	10	10	10	10	10	10	D	1
Minimum load (% of full load)	50	50	50	50	50	50	50	50	D	1
Warm start-up time (hours)	0,25	0,25	0,25	0,25	0,25	0,25	0,25	0,25	G	1
Cold start-up time (hours)	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5		1
Environment										
SO_2 (degree of desulphuring, %)	95,5	96,4	99,1	99,8	90,9	99,8	95,5	99,9	F	1
NO_X (g per GJ fuel)	90	72	55	44	55	90	44	55	F	1
CH4 (g per GJ fuel)	16	11	8	4	4	16	2	16	F	1
N2O (g per GJ fuel)	1	1	1	1	1	3	0	1	F	1
Particles (g per GJ fuel)	2,0	0,3	0,3	0,3	0,1	2,0	0,1	1,0	F	1
Financial data										
Nominal investment (M€/MWe)	7,0	6,8	6,4	6,2	5,9	8,0	5,2	8,4	E,J,K	1
- of which equipment	3,9	3,8	3,6	3,6	3,3	4,5	3,0	4,9	K	
- of which installation	3,0	3,0	2,8	2,6	2,6	3,5	2,1	3,6	K	

Fixed O&M (€/MWe/year)	323.800	318.200	306.800	298.000	276.300	365.100	235.200	378.700	J	
Variable O&M (€/MWh_e)	4,0	4,0	4,0	4,0	3,4	4,6	3,0	5,1	J	
Technology specific data										
Steam reheat	None	None	None	None	None	None	None	None		
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	1,05	1,02	0,97	0,92	0,89	1,20	0,77	1,25	E,J,K	1
- of which equipment	0,59	0,58	0,55	0,53	0,50	0,68	0,45	0,72	K	
- of which installation	0,46	0,44	0,42	0,38	0,39	0,52	0,32	0,53	K	
Fixed O&M (€/MW input/year)	48.600	47.700	46.100	44.100	40.800	55.300	34.200	56.500	J	
Variable O&M (€/MWh input)	0,60	0,60	0,60	0,60	0,51	0,69	0,45	0,75	J	
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,080	0,078	0,074	0,067	0,068	0,092	0,056	0,093	K	

Notes:

A The plant is directly producing hot water for District Heating by burning fuel on a grate. The electric power is produced by an ORC module (Organic Rankine Cycle; Waste Heat Recovery - WHR). Refer for instance to the following link for further information about technology and suppliers: http://www.enova.no/upload_images/36AC689098414B05A7112FA2EE985BDA.pdf . This is low temperature and low efficiency electric power but at an affordable price.

B Boilers up to 20 MW fuel input for hot water production are more or less standardized products with a high degree of fuel flexibility (type of biomass, humidity etc.)

C Since straw is relatively dry there is often only a minor efficiency advantage in using flue gas condensation. There is though an environmental advantage in having a scrubber in the flue gas stream. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.

D Secondary regulation normally relates to power production; for this type of plant it may not be of importance. Though, the load control of the heat production is important and most units will perform better than the figure shown. Also, minimum load could be substantially lower.

E Since electricity generation is only a secondary objective for minor heat producers, it may make more sense to relate the total investment only to the heat production capacity.

F It is anticipated that for the smaller units the supplier has a SNCR solutiuon to limit NOx emissions. SO2, CH4 and N2O emissions are low when combusting biomass.

G Warm start is starting with a glowing fuel layer on the grate.

H The total efficiency is the sum of electricity efficiency and heat efficiency, applicable for "name plate" and "annual average", respectively. The "annual average" electricity efficiency is lower than "name plate" due to turbine outages and other incidents. The resulting lost power production is recovered as heat. This is why "annual average" heat efficiency is higher than "name plate" heat. Efficiencies refer to lower heating value. The parasitic electricity consumption has been subtracted in the listed electricity efficiencies.

I The Cv value does not exist for plants with a back pressure turbine or an ORC turbine

J Investment applies to a standard plant. There could be cost related to the actual project or site that adds to the total investment, e.g. additional fuel storage, facilities for chipping of logs, conditions for foundation and harbour facilities.
Financial data and Technological specific data are essentially the total cost either divided by the electric net capacity, i.e. corresponding to the indicated name plate efficiencies, or by the thermal input. This is to indicate that new plants may not fully take advantage of the technical capabilities for full electricity production capacity. The two cost for electricity and thermal input, respectively, are not to be added up!

K Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies. NOTICE: There are to our knowledge no references on ORC plants running on straw.

Data sheets Straw CHP, medium

Technology	Medium Straw CHP, 80 MW feed									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	24,8	24,4	24,5	24,5	23,5	25,1	24,1	25,2	A	
Electricity efficiency, net (%), name plate	31,0	30,5	30,6	30,6	29	31	30	32	A, H	1
Electricity efficiency, net (%), annual average	29,4	29,0	29,1	29,1	26	30	27	30	A, H	1
Heat efficiency, net (%), name plate	67,3	67,7	67,6	67,6	54	69	54	68	B, H	1
Heat efficiency, net (%), annual average	68,8	69,3	69,2	69,2	57	71	57	70	B, H	1
Additional heat potential with heat pumps (% of thermal input)	1,7	1,7	1,7	1,7	2	14	2	14	C	1
Cb coefficient (40°C/80°C)	0,46	0,45	0,45	0,45	0,43	0,46	0,45	0,47		
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	I	
Forced outage (%)	4	4	4	4	4	4	4	4		
Planned outage (weeks per year)	4,0	4,0	4,0	4,0	3,4	4,6	3,0	5,0		
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	2,5	2,5	2,5	2,5	2	3	1,5	3		1
Space requirement (1000 m2/MWe)	0,3	0,3	0,3	0,3	0,2	0,3	0,2	0,4		
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA		
Secondary regulation (% per minute)	4	4	4	4	4	4	4	4	D	1
Minimum load (% of full load)	40	40	40	40	40	40	40	40		
Warm start-up time (hours)	2	2	2	2	2	2	2	2	E	1
Cold start-up time (hours)	8	8	8	8	8	8	8	8		1
Environment										
SO_2 (degree of desulphuring, %)	95,5	96,4	99,1	99,8	90,9	99,8	95,5	99,9	F	1
NO_X (g per GJ fuel)	87	70	47	29	18	87	7	47	F	1
CH4 (g per GJ fuel)	0	0	0	0	0	0	0	0	F	1
N2O (g per GJ fuel)	1	1	1	1	1	3	0	1	F	1
Particles (g per GJ fuel)	2,0	0,3	0,3	0,3	0,1	2,0	0,1	1,0	F	1
Financial data										
Nominal investment (M€/MWe)	3,7	3,8	3,6	3,3	3,1	4,5	2,6	4,5	J,K	1
- of which equipment	2,3	2,3	2,2	2,0	1,8	2,7	1,6	2,8	J,K	1
- of which installation	1,5	1,5	1,4	1,3	1,3	1,7	1,0	1,7	J,K	1
Fixed O&M (€/MWe/year)	150.400	149.900	141.100	126.300	129.400	168.700	98.000	158.100	J	1
Variable O&M (€/MWh_e)	1,9	2,0	2,0	2,0	1,7	2,3	1,5	2,4	J	1
Technology specific data										
Steam reheat	None	None	None	None	None	None	None	None		
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes		

Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	1,16	1,16	1,10	1,00	0,95	1,36	0,81	1,37	J,K	1
- of which equipment	0,70	0,71	0,68	0,62	0,56	0,84	0,49	0,84	K	
- of which installation	0,46	0,45	0,42	0,38	0,39	0,53	0,32	0,53	K	
Fixed O&M (€/MW input/year)	46.600	45.800	43.200	38.700	38.000	53.000	29.600	49.900	J	
Variable O&M (€/MWh input)	0,60	0,60	0,60	0,60	0,51	0,69	0,45	0,75	J	
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,070	0,068	0,065	0,059	0,060	0,081	0,049	0,081	K	

Notes:

A The boiler in the plant is grate fired producing steam to be used in a subsequent back pressure steam turbine. Though a grate is reasonable flexible with respect to combusting different fuels the fuel feed system will be dependent on the type of fuel used.

B Through a turbine by-pass all the produced steam energy can be used for District Heat production.

C Since straw is relatively dry there is often only a minor efficiency advantage in using flue gas condensation. There is though an environmental advantage in having a scrubber in the flue gas stream. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.

D Secondary regulation normally relates to power production; for this type of plant it may not be of importance since load will normally follow heat consumption.

E A limiting factor for the hot and cold start-up times is the size of the hot water tank (deaerator).

F For NOx-emissions no lower than 40 g/GJ SNCR is assumed. It is probably necessary to include a tail-end SCR catalyst to fulfill expected BREF requirements, particularly after year 2030. This has slight adverse effect on the electricity efficiency.

G Warm start is starting with a glowing fuel layer on the grate and a warm deaerator.

H The total efficiency is the sum of electricity efficiency and heat efficiency, applicable for "name plate" and "annual average", respectively. The "annual average" electricity efficiency is lower than "name plate" due to turbine outages and other incidents. The resulting lost power production is recovered as heat. This is why "annual average" heat efficiency is higher than "name plate" heat. Efficiencies refer to lower heating value. The parasitic electricity consumption has been subtracted in the listed electricity efficiencies.

I The Cv value does not exist for plants with a back pressure turbine or an ORC turbine

J Investment applies to a standard plant. There could be cost related to the actual project or site that adds to the total investment, e.g. additional fuel storage, facilities for chipping of logs, conditions for foundation and harbour facilities.
Financial data and Technological specific data are essentially the total cost either divided by the electric net capacity, i.e. corresponding to the indicated name plate efficiencies, or by the thermal input. This is to indicate that new plants may not fully take advantage of the technical capabilities for full electricity production capacity. The two cost for electricity and thermal input, respectively, are not to be added up!

K Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies.

Data sheets Straw CHP, large

Technology	**Large Straw CHP, 132 MW feed**									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	40,7	40,7	40,9	40,9	39,1	53,4	40,3	54,5	A	

Electricity efficiency, net (%), name plate	30,9	30,9	30,9	30,9	30	40	30	41	A, H	1
Electricity efficiency, net (%), annual average	29,3	29,3	29,4	29,4	27	38	27	39	A, H	1
Heat efficiency, net (%), name plate	67,9	67,9	67,8	67,8	45	69	44	68	B, H	1
Heat efficiency, net (%), annual average	69,5	69,5	69,4	69,4	48	71	47	70	B, H	1
Additional heat potential with heat pumps (% of thermal input)	1,7	1,7	1,7	1,7	2	14	2	14	C	1
Cb coefficient (40°C/80°C)	0,45	0,45	0,46	0,46	0,44	0,60	0,45	0,61		
Cv coefficient (40°C/80°C)	1	1	1	1	1	1	1	1	I	
Forced outage (%)	3	3	3	3	3	3	3	3		
Planned outage (weeks per year)	3	3	3	3	2,6	3,5	2,3	3,8		
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	3	3	3	3	2,5	3,5	2	3,5		1
Space requirement (1000 m2/MWe)	0,2	0,2	0,2	0,2	0,2	0,3	0,2	0,3		
Primary regulation (% per 30 seconds)	2	2	2	2	2	2	2	2		
Secondary regulation (% per minute)	4	4	4	4	4	4	4	4	D	1
Minimum load (% of full load)	40	40	40	40	40	40	40	40		
Warm start-up time (hours)	2	2	2	2	2	2	2	2	E	1
Cold start-up time (hours)	8	8	8	8	8	8	8	8		1
Environment										
SO_2 (degree of desulphuring, %)	95,5	96,4	99,1	99,8	90,9	99,8	95,5	99,9	F	1
NO_X (g per GJ fuel)	84	67	36	18	18	84	7	36	F	1
CH4 (g per GJ fuel)	0	0	0	0	0	0	0	0	F	1
N2O (g per GJ fuel)	1	1	1	1	1	3	0	1	F	1
Particles (g per GJ fuel)	0,3	0,3	0,3	0,3	0,1	2,0	0,1	1,0	F	1
Financial data										
Nominal investment (M€/MWe)	3,5	3,5	3,3	3,0	2,9	4,1	2,4	4,1	J,K	1
- of which equipment	2,2	2,1	2,0	1,8	1,8	2,5	1,5	2,5	J,K	
- of which installation	1,4	1,3	1,3	1,1	1,2	1,6	0,9	1,6	J,K	
Fixed O&M (€/MWe/year)	128.700	124.900	117.300	104.700	109.600	110.400	81.500	101.600	J	
Variable O&M (€/MWh_e)	1,9	1,9	1,9	1,9	1,7	2,2	1,5	2,4	J	
Technology specific data										
Steam reheat	None	None	None	None	None	Yes	None	Yes		
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	1,09	1,07	1,01	0,92	0,90	1,25	0,74	1,26	J,K	1
- of which equipment	0,67	0,66	0,63	0,57	0,55	0,77	0,45	0,78	K	
- of which installation	0,42	0,41	0,39	0,35	0,36	0,48	0,29	0,48	K	
Fixed O&M (€/MW input/year)	39.700	38.500	36.300	32.400	32.500	44.600	24.900	41.900	J	
Variable O&M (€/MWh input)	0,60	0,60	0,60	0,60	0,51	0,69	0,45	0,75	J	
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,065	0,063	0,060	0,055	0,055	0,075	0,045	0,075	K	

Notes:

A The boiler in the plant is grate fired producing steam to be used in a subsequent back pressure steam turbine. Though a grate is reasonable flexible with respect to combusting different fuels the fuel feed system will be dependent on the type of fuel used.

B Through a turbine by-pass all the produced steam energy can be used for District Heat production.

C Since straw is relatively dry there is often only a minor efficiency advantage in using flue gas condensation. There is though an environmental advantage in having a scrubber in the flue gas stream. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.

D Secondary regulation normally relates to power production; for this type of plant it may not be of importance since load will normally follow heat consumption.

E A limiting factor for the hot and cold start-up times is the size of the hot water tank (deaerator).

F For NOx-emissions no lower than 40 g/GJ SNCR is assumed. It is probably necessary to include a tail-end SCR catalyst to fulfill expected BREF requirements, particularly after year 2030. This has slight adverse effect on the electricity efficiency.

G Warm start is starting with a glowing fuel layer on the grate and a warm deaerator.

H The total efficiency is the sum of electricity efficiency and heat efficiency, applicable for "name plate" and "annual average", respectively. The "annual average" electricity efficiency is lower than "name plate" due to turbine outages and other incidents. The resulting lost power production is recovered as heat. This is why "annual average" heat efficiency is higher than "name plate" heat. Efficiencies refer to lower heating value. The parasitic electricity consumption has been subtracted in the listed electricity efficiencies.

I The Cv value does not exist for plants with a back pressure turbine or an ORC turbine

J Investment applies to a standard plant. There could be cost related to the actual project or site that adds to the total investment, e.g. additional fuel storage, facilities for chipping of logs, conditions for foundation and harbour facilities.
Financial data and Technological specific data are essentially the total cost either divided by the electric net capacity, i.e. corresponding to the indicated name plate efficiencies, or by the thermal input. This is to indicate that new plants may not fully take advantage of the technical capabilities for full electricity production capacity. The two cost for electricity and thermal input, respectively, are not to be added up!

K Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies.

10 Stirling engines, gasified biomass (go to previous catalogue)

There are no plans to update this chapter.

For now please look at the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

11 Solid oxide fuel cell CHP (natural gas/biogas)

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Energinet: Rune Grandal, rdg@energinet.dk
Author: DTU Energy, Jonathan Hallinder, Eva Ravn Nielsen in cooperation with Ea Energy Analyses.
Adapted from "Technology Data for Hydrogen Technologies" (2016), prepared as part of the project "Analysis for Commercialization of Hydrogen Technologies" under the Danish Energy Technology Development and Demonstration Programme (EUDP).

Review: DGC

Publication date

March 2018

Amendments after publication date

Date	Ref.	Description
-	-	-
-	-	-

Qualitative description

Brief technology description

Solid oxide fuel cell based combined heat and power systems (SOFC-CHP), or SOFC Distributed Generation, typically use natural gas or biogas as fuel and, therefore, they can simply be connected to the gas grid like conventional natural gas boilers. Alternatively, SOFC-CHP can also utilise hydrogen and syngas or propane/LPG or diesel as fuel. A CHP system produces both electricity and heat. The electricity can be used directly at the production site, be fed into the electrical grid or in remote areas be the sole source of electricity substituting a diesel generator. The produced heat can either be used directly at the site or delivered to a district heating grid.

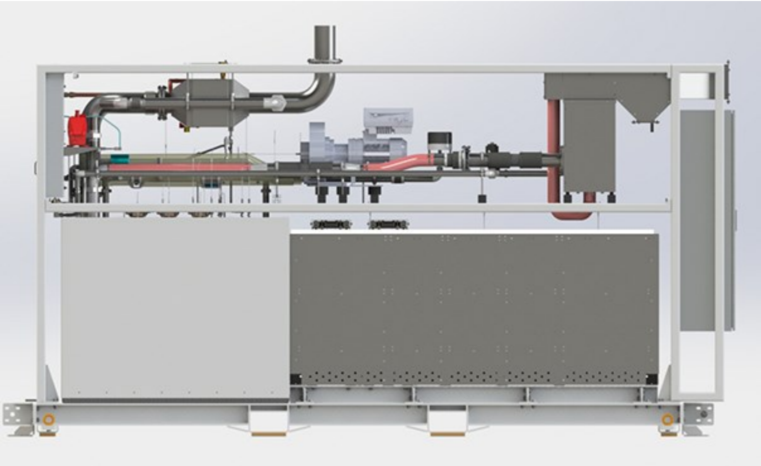


Figure 1: SOFC unit from Sunfire for combined heat and power for commercial use [9].

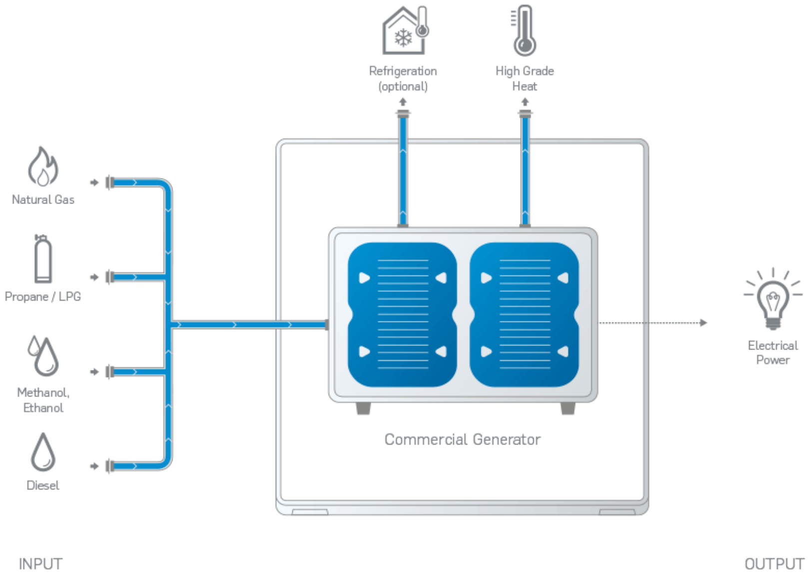


Figure 2: Schematic illustration of an SOFC unit for combined heat and power for commercial use from Sunfire illustrating the flexibility in input fuels [9].

Figure 3: C50 module from Convion with 50 kW. Systems up to 300 kW are being developed [10].

Input
Natural gas or biogas.

Output
Electricity and heat.

The product can be designed to meet the requirements for district heating, but the present early products focus mainly on providing power. The fuel cell is operated at very high temperatures (600-700 degree Celsius) allowing the surplus heat to be used for high temperature industrial processes.

In the data sheet CHP systems are only considered from 2020.

With minor adaption to the feeding system a SOFC unit may also be fuelled with ethanol and ammonia.

Typical capacities
Today, no large scale SOFC-CHP systems are available at the market, but they can be aligned with the sizes of pure distributed generation units used for baseload and backup, e.g. SOFC systems like systems provided by Bloom energy. These systems are today available in modules up to 250 kW_e power, but as mentioned above these modules can be clustered to achieve larger plants [1].

SOFC-CHP systems are also available in very small scale including mCHP plants for households.

Space requirement
23 m^2/MW_e (based on one Energy Server 5 + five UPM-571 modules from Bloom Energy [11] of 1.25 MW in total).

Regulation ability
The fuel cell CHP system can modulate, but the high temperature of reformer and fuel cell requires the hot part to be kept at a high temperature to facilitate modulating.

SOFC systems can be designed to regulate below 30% of nominal load without any significant loss of efficiency. The response time can be very short (a few seconds) when the system is in standby mode.

Advantages/disadvantages
The main advantages include:

- SOFC-CHP units produce both electricity and heat in cogeneration with higher electrical efficiency than for other cogeneration technologies in the same power range fuelled by natural gas or biogas.
- Decentralised cogeneration of electricity and heat minimises grid losses and the need for additional infrastructure investments.
- The required gas quality is less strict compared to gas engines. SOFC-CHP units are more flexible in relation to fuels and can run on different types of gasses (methane, syngas, hydrogen and biogas) without them being upgraded to SNG. This means that natural gas

fuelled SOFC-CHP can be operated from the natural gas grid even if the natural gas is exchanged with synthetic natural gas (SNG).
- Unlike conventional power plants, the produced CO_2 is not mixed with oxygen and nitrogen from the atmosphere. This makes it easier and more cost-efficient to capture and store the produced CO_2.

The main disadvantages include:

- Currently, lifetime of the stacks is relatively short. Some manufacturers do however report a stack life-time of about 6 years when operating in baseload. Several replacements of stacks may be relevant during the lifetime of the plant.
- Long start-up times from a cold start.

Environment
The emissions from natural gas fuelled SOFCs are relatively low compared to electricity produced at central power plants. Because there is no combustion of fuels (it is a chemical reaction), the emission of for example NO_x is lower than what is emitted from a traditional power plant. If biogas (fossil free gas) is used the operation of the plant can be considered carbon neutral. Today, the most common used material for the anode in SOFCs consist of nickel mixed with yttria-stabilized zirconia (YSZ). In the production and end of life disposal, the use of nickel is a concern as it is carcinogenic.

Research and development perspectives
SOFC-CHP units are still under development. The development is concentrated on reducing the costs of the units, increasing the lifetime and increasing the reliability.

In a later phase, the research and development activities may be concentrated on how to use the units in a smart grid context so that fuel cells can optimize their operation according to dynamic electricity prices.

BloomEnergy from USA is developing and has commercialized fuel cell systems for base load / backup power, meaning systems where only the power is used and the heat considered waste. Thus, they are not developing CHP systems they are the only player on the commercial market with SOFC systems in the adequate power range. A few other companies are getting close to realizing their first commercial SOFC CHP units, for example Mitsubishi ([1], [2]), Sunfire and Convion.

Figure 4: BloomEnergy SOFC system. The dashed region corresponds to ine 250 kW_e unit [1].

Examples of market standard technology

Large scale SOFC units for power supply can be purchased from BloomEnergy, Convion and Sunfire. The first two focus on providing power, whereas the latter focus on a reversible system that can alternate between providing power and providing hydrogen (SOFC/SOEC).

No CHP systems in the relevant power range are available; therefore, the Bloom Energy ES-5710 unit has been selected as the reference system. This system is a power producing system and does not utilise the produced heat.

Prediction of performance and costs

The technology is classified between Category 1: Research and development and Category 2: Pioneer phase, demonstration.

The typical generation capacity is expected to increase from around 2.5 MW in 2020 to around 20 MW in 2050, while the electrical efficiency is expected to increase to 60%. The investment costs of the SOFC CHP are projected to decrease from 3.3 M€$_{2015}$/MW in 2020 to 0.6 M€$_{2015}$/MW in 2050. The projection is based on Cost Study for Manufacturing of Solid Oxide Fuel Cell Power Systems, 2013, Pacific Northwest National Laboratory prepared for the U.S. Department of Energy [13]. In 2020, an annual production of 50 units is assumed, in 2030 a yearly production of 250 units is assumed, and in 2050, a production of 4000 units per year is assumed.

For comparison the Technology Roadmap - Hydrogen and Fuel Cells, 2015, International Energy Agency [12], estimates a cost reduction to around 1.8 M€$_{2015}$/MW between 2025 and 2035.

Uncertainty

The uncertainty related to the cost projection is very significant and is affected by challenges such as lifetime improvements, improved operational flexibility and reduction of investment costs as a result of mass production.

Economy of scale

-

Additional remarks

No additional remarks.

Data sheets

Technology	SOFC - CHP Natural Gas / Biogas									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Reference**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	0.25	2.5	10	20					A	3; *; *; *
Electricity efficiency (condensation mode for extraction plants), net (%), name plate	56	58	60	60						
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	56	58	60	60	52	60	56	62	B	3; *; *; *
Cb coefficient (50°C/100°C)	-	1.67	1.61	1.61					C, L	-; *; *; *
Cv coefficient (50°C/100°C)	-	-	-	-						
Forced outage (%)										
Planned outage (weeks per year)										
Technical lifetime (years)	15	20	20	20					D	6; 6; *; *
Construction time (years)	1	1	1	1						
Regulation ability										
Primary regulation (% per 30 seconds)										
Secondary regulation (% per minute)										
Minimum load (% of full load)	70	70	70	70						
Warm start-up time (hours)	0.025	0.025	0.025	0.025					E	
Cold start-up time (hours)	25	25	25	25					E	*; *; *; *
Environment										
SO_2 (degree of desulphuring, %)	100	100	100	100						3
NO_X (g per GJ fuel)	1.3	1.4	1.5	1.6						3
CH4 (g per GJ fuel)	1.25	1.25	1.25	1.25					F	7
N2O (g per GJ fuel)	NA	NA	NA	NA					F	*
Financial data										
Nominal investment (M€/MW)	8.3	3.3	2	0.8	2.7	5.8	0.4	1.3	G, H, I, J	8, 13
- of which equipment	6.64	2.3	1.2	0.464					G	
- of which installation	1.66	1.0	0.8	0.336					G	
Fixed O&M (€/MW/year)	415,000	165,000	100,000	40,000	135,000	290,000	20,000	65,000	K	8
Variable O&M (€/MWh)	-									
Startup cost (€/MW/startup)	-									

Notes:

A Installed systems consist of modules of app. 200 kWel power, these modules can be clustered into larger units. Today, often up to app. 2 MWel power and upwards. [5,8]

B The electrical efficiency (based on the lower heating value, LHV) of Bloom Energy's systems decreases from an initial value of 60 % to 52 % by the end-of life for the stacks. This gives an average electrical efficiency of 56 % for the life-time of a stack. Uncertainties represent the aforementioned interval.

C No CHP-systems in this power range are available, therefore, Bloom Energy ES-5710 unit has been chosen as the reference system. This system is a power producing system and does not take the produced heat into account. . The produced heat can be used as thermal storage, hot water production, heating or for feed in to the distributed heating system. High total efficiencies can be expected as the systems are compact and with a small surface area, leading to low heat losses and thereby high total system efficiency. Thus it is not unrealistic to assume a total efficiency above 90 % (thermal efficiency > 35 %) for this type of system.

D Values correspond to the durability for the whole plant; the stack may be exchanged several times during the life time of the plant.

E Start up from outdoor temperature or room temperature takes rather long time, this is mainly due to the large amount of ceramic material which require slow heating ramps. If the system is at operating temperature the stack can be started up quickly, assuming that gases are supplied and help systems are active. Also shut down can be performed quickly, not counting in the time required to cool the system.

F Value for SOFC microCHP systems used here, since SOFC-CHP's has the same operating principle.

G A bloom unit costs approximately 6600 euro per kWel. To this must the installation costs be added, which of course depends on the location and the size of the unit. Additional costs are also to cover for necessary modifications of the system, e.g. implementation of hot water storage and subsystems for exporting the heat from the unit to surrounding buildings or distributed heating grid.

H Start up from outdoor temperature or room temperature takes rather long time, this is mainly due to the large amount of ceramic material which require slow heating ramps. If the system is at operating temperature the stack can be started up quickly, assuming that gases are supplied and help systems are active. Also shut down can be performed quickly, not counting in the time required to cool the system.

I The best estimates for nominal investments in 2020, 2030 and 2050 are estimated from [9]. In 2020 an annual production of 50 units is assumed, in 2030 a yearly production of 250 units is assumed, and in 2050 a production of 4000 units per year is assumed.

J Estimation of uncertainties for investment costs are estimated from [9] with an annual production of 10/150 units in 2020 and 1000/10000 units in 2050

K Fixed O&M costs are estimated as 5% of the investment cost.

L The heat efficiency, which can be derived, depends on the return temperature of the cooling circuit and the size of the heat exchanger.

References

[1] BloomEnergy, www.bloomenergy.com, 2014-11-11,

[2] Technology, https://www.mhps.com/en/technology/index.html, 2014-11-14.

[3] BloomEnergy, *Product datasheet: ES-5710 Energy Saver*, November 2014: http://c0688662.cdn.cloudfiles.rackspacecloud.com/downloads_pdf_Bloomenergy_DataSheet_ES-5710.pdf.

[4] BloomEnergy, Product datasheet: ES-5700 Energy Saver, November 2014: http://c0688662.cdn.cloudfiles.rackspacecloud.com/downloads_pdf_Bloomenergy_DataSheet_ES-5700.pdf.

[5] Iskov H., Rasmussen N.B., Danish gas Technology centre, 2013, *"Update of technology data for energy plants: Fuel cells, electrolysis and technologies for bio-SNG"*.

[6] Fuel Cell and Hydrogen Joint Undertaking: *"Multi – Annual Work Plan 2014-2020"*, adopted 2014-06-30.

[7] http://www.asue.de, 2014-11-17.

[8] Bloom Energy Server, http://en.wikipedia.org/wiki/Bloom_Energy_Server, 2015-02-02.

[9] Cogeneration in public facilities - flexible and green, http://www.sunfire.de/en/applications/commercial, 2016-08-31.

[10] Convion product focus, http://convion.fi/products/

[11] UPM-571 Uninterruptible Power Module, http://www.bloomenergy.com/fuel-cell/upm-571-data-sheet/, 2016-08-31.

[12] International Energy Agency, 2015, Technology Roadmap - Hydrogen and Fuel Cells.

[13] Pacific Northwest National Laboratory, 2013, Cost Study for Manufacturing of Solid Oxide Fuel Cell Power Systems, prepared for the U.S. Department of Energy.

12 Low temperature proton exchange membrane fuel cell CHP (hydrogen)

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk

Energinet: Rune Grandal, rdg@energinet.dk

Author: Dantherm. Adaptation from *Technology Data for Hydrogen Technologies* by Ea Energy Analyses

Review: DGC

Publication date

March 2018

Amendments after publication date

Date	Ref.	Description
-	-	-
-	-	-

Qualitative description

Brief technology description

Fuel cells are electrochemical devices that convert fuel into electricity and heat. Generally, the conversion efficiency from fuel to electricity is high in a fuel cell and the technology is scalable without loss of efficiency. The proton exchange membrane (PEM) fuel cell consists of a cathode and an anode made of graphite and a proton-conducting polymer as the electrolyte as shown in Figure 1 [1].

Low temperature PEM fuel cells operate at temperatures below 100°C (typically around 80°C) since the membrane must be saturated by water.

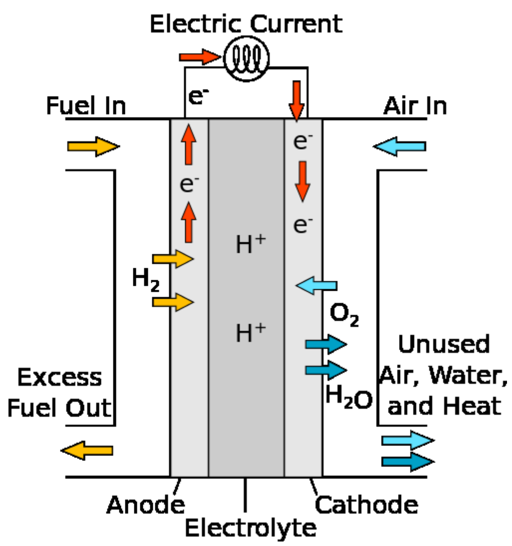


Figure 1: Diagram of a PEM-FC [2].

Today, the larger power and heat generating units FC-CHP are typically arranged for integration in conjunction with industrial processes where hydrogen is a waste gas from the industrial processes e.g. production of chloric gas. In many of the early units, only the electricity as output is used. In the future, the hydrogen used for the fuel cell may be produced from electrolysis based on fossil free electricity.

Additionally, the potential of the LT-PEM fuel cell for transport purposes and within the area of mCHP installations has been estimated to be significant [1].

Figure 2: A 50 kW LT-PEMFC CHP hydrogen unit from Dantherm Power.

Input
Hydrogen.

Output
Electricity and heat.

Typical capacities
The larger FC-CHP units are typical around 20 to 1,000 kW of electrical power.

Regulation ability
The technology has good part-load and transient properties. The regulation of PEM systems can be designed to achieve close to 0% nominal load without significant loss of efficiency. Furthermore, the start-up time of the technology is short and the fuel cells can start and operate at room temperature and has no problems with frequent thermal cycling (start/stop). Response time from cold start during hard frost is very short – down to a few seconds.

Advantages/disadvantages

The main advantages include:

- The PEM-FC utilises the scalability of the fuel cell technology to produce electricity locally with efficiencies equal to or higher than for conventional power plants.
- Larger FC-CHP units in the grid can support the grid companies in balancing the grid.
- The grid balancing property of the PEM-FC contributes to reduced additional investments in infrastructure e.g. cables.
- Hydrogen produced from excess electricity based on renewable sources can be stored in hydrogen storages and utilised in the PEM-FC in situations, where wind turbines, solar PV and other renewable technologies are not available.

The main disadvantages include:

- Relatively high production costs today due to expensive materials (platinum).
- The lifetime of the current technology needs to be improved.

Environment

If the hydrogen is produced from fossil free electricity, the operation of the LT-PEMFC is carbon neutral.

The exhaust gas does not contain NO_x and SO_2.

Research and development perspectives

The Danish research, development and demonstration program on fuel cell based CHP is of international level compared to similar programs in Germany, Japan, Korea and North America.
The fuel cell technology has shown high electrical efficiency above the efficiencies of competing power generation technologies. However, the fuel cell technology still needs to be matured on issues like lifetime and cost reduction. It is expected that the Danish fuel cell technology will mature to a commercial level within this decade.

Examples of market standard technology

Demonstration plants of 50 kW FC-CHP units were produced by Dantherm Power in 2010 and 2011 and delivered to South Africa and South Korea. A 1,000 kW unit from Nedstack was set in operation in 2011 in Arnhem, Holland; the Ballard Power Systems 1,000 kW unit has been in operations in California since 2012.

Prediction of performance and costs

Since the technology is still relatively immature, the technology is placed in Category 2: Pioneer phase, demonstration. This also means that there is significant uncertainty related to the projection of future costs, which relate to both overcoming technological challenges and the future market and demand for the technology.

In the Technology Data for Hydrogen Technologies [4], the investment costs are projected to decrease to 1.1 $M€_{2015}$/MW by 2030 and 0.8 $M€_{2015}$/MW by 2050. For comparison the IEA projects a decrease from 1.5 M€/MW in 2020 to 0.7 M€/MW in 2030 and 0.6 M€/MW by 2050, in its Technology Roadmap - Hydrogen and Fuel Cells, 2015.

The typical generation capacity is expected to increase from around 0.1 MW in 2020 to approximately 2 MW in 2050, while the electrical efficiency is expected to increase to 50%.

Uncertainty

The uncertainty related to the cost projection is significant and is affected by challenges such as lifetime improvements, introduction of cheaper materials and improved market share resulting in economy of scale synergies. The uncertainty of the cost projection in 2050 is estimated to be +/- 50%.

Economy of scale

-

Additional remarks

No additional remarks.

Data sheets

Technology	LT-PEMFC CHP hydrogen gas									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	0.05	0.1	1	2						1
Electricity efficiency (condensation mode for extraction plants), net (%), name plate	45	50	50	50						1
Electricity efficiency (condensation mode for extraction plants), net (%), annual average	45	50	50	50	45	52	46	53	A	1, 2
Cb coefficient (50°C/100°C)	-	1.25	1.25	1.25					D	
Cv coefficient (50°C/100°C)	-	-	-	-						
Forced outage (%)	0.1	0.1	0.1	0.1						
Planned outage (weeks per year)		0.1	0.1	0.1						
Technical lifetime (years)	10	10	10	10						1
Construction time (years)	1	1	1	1						
Regulation ability										
Primary regulation (% per 30 seconds)	50	25	2.5	1.25						
Secondary regulation (% per minute)										
Minimum load (% of full load)	10	10	10	10						
Warm start-up time (hours)	0.01	0.01	0.01	0.01						
Cold start-up time (hours)										
Environment										
SO_2 (degree of desulphuring, %)	100	100	100	100						
NO_X (g per GJ fuel)	0	0	0	0						
CH4 (g per GJ fuel)	0	0	0	0						
N2O (g per GJ fuel)	0	0	0	0						
Financial data										
Nominal investment (M€/MW)	1.9	1.3	1.1	0.8	1.1	1.6	0.5	0.9	B	3, 2
- of which equipment	1.6	1.0	0.8	0.6						3
- of which installation	0.3	0.3	0.3	0.2						3
Fixed O&M (€/MW/year)	95,000	65,000	55,000	40,000					C	
Variable O&M (€/MWh)										
Technology specific data										
Minimum load efficiency (%)	30	35	35	35						1

Notes:

A Uncertainties for efficiency based on [2]
B Estimation of uncertainties for nominal investment costs based on [2]
C Fixed O&M costs are estimated to 5% of the investment cost based on [2]
D The heat efficiency, which can be derived, depends on the return temperature of the cooling circuit and the size of the heat exchanger.

References

[14] Partnerskabet for brint og brændselsceller, *Fuel Cell Technologies,* http://www.hydrogennet.dk/358/, *visited 01.11.2016*.

[15] Wikipedia, Proton exchange membrane fuel cell, https://en.wikipedia.org/wiki/Proton_exchange_membrane_fuel_cell, visited 01.11.2016.

[16] International Energy Agency. 2015. *Technology Roadmap - Hydrogen and Fuel Cells.*

[17] Ea Energy Analyses et al. 2016, *Technology Data for Hydrogen Technologies*.

[18] Practical data and expert opinion from Dantherm Power

20 Wind Turbines onshore

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Author: Mads V. Sørensen / Per Nielsen (EMD)

Publication date

August 2016

Amendments after publication date

Date	Ref.	Description

Qualitative description

Brief technology description

The typical large onshore wind turbine being installed today is a horizontal-axis, three bladed, upwind, grid connected turbine using active pitch, variable speed and yaw control to optimize generation at varying wind speeds.

Wind turbines work by capturing the kinetic energy in the wind with the rotor blades and transferring it to the drive shaft. The drive shaft is connected either to a speed-increasing gearbox coupled with a medium- or high-speed generator, or to a low-speed, direct-drive generator. The generator converts the rotational energy of the shaft into electrical energy. In modern wind turbines, the pitch of the rotor blades is controlled to maximize power production at low wind speeds, and to maintain a constant power output and limit the mechanical stress and loads on the turbine at high wind speeds. A general description of the turbine technology and electrical system, using a geared turbine as an example, can be seen in figure 1.

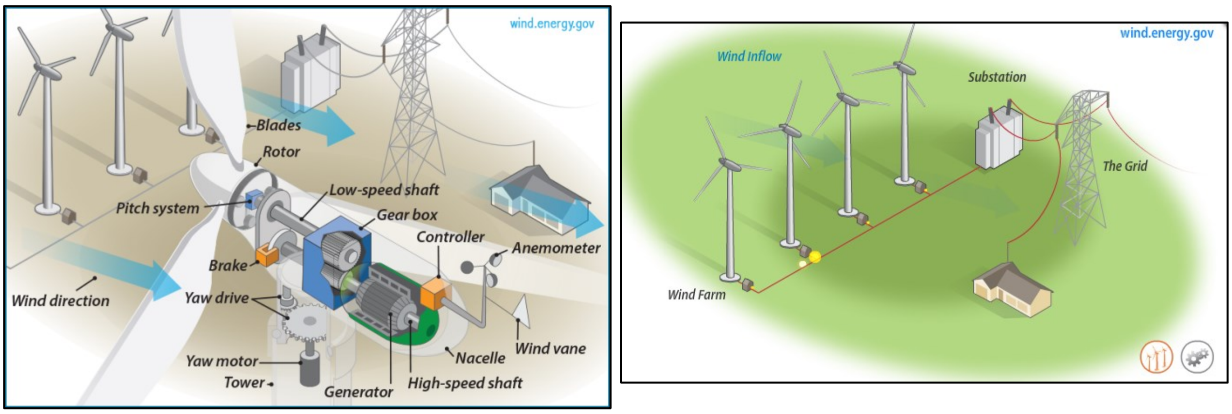


Figure 1: General turbine technology and electrical system.

Wind turbines are designed to operate within a wind speed range which is bounded by a low “cut-in” wind speed and a high “cut-out” wind speed. When the wind speed is below the cut-in speed the energy in the wind is too low to be utilized. When the wind reaches the cut-in speed, the turbine begins to operate and produce electricity. As the wind speed increases, the power output of the turbine increases, and at a certain wind speed the turbine reaches its rated power. At higher wind speeds, the blade pitch is controlled to maintain the rated power output. When the wind speed reaches the cut-out speed, the turbine is shut down or operated in a reduced power mode to prevent mechanical damage.

Onshore wind turbines can be installed as single turbines, clusters or in larger wind farms.

Commercial wind turbines are operated unattended, and are monitored and controlled by a supervisory control and data acquisition (SCADA) system.

Input

Input is wind.

Cut-in wind speed: 3 – 4 m/s.

Rated power generation wind speed: 10-12 m/s, depending on the specific power (defined as the ratio of the rated power to the swept rotor area).

Cut-out or transition to reduced power operation at wind speed: 25 m/s.

In the future, it is expected that manufacturers will apply a soft cut-out for high wind speeds (indicated with dashed red curve in figure 2) resulting in a final cut-out wind speed around 30 m/s.

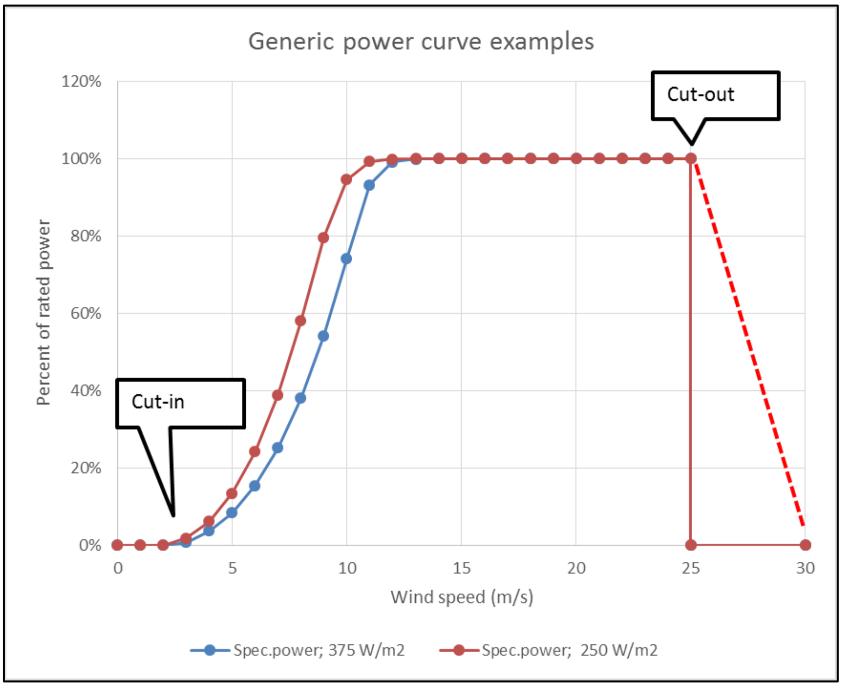


Figure 2: Turbine power curves (Information's from expert workshop held by DEA 27-4-2015)Specific power values refer to e.g. 3 MW with 124m rotor diameter (250 W/m^2) and 3 MW with 101 m rotor diameter (375 W/m^2)

The power in the wind is given by the formula P = ½*rho*A*u^3, where rho is the air density, A the swept area and u the wind speed. To calculate the net power output from a wind turbine, the result must be multiplied by C_p (Coefficient of power). C_p varies with wind speed and has a maximum of around 45%, which is typically reached at ~8 m/s, depending on the specific power.

Output

The output is electricity.

Typical modern onshore turbines located in Denmark have capacity factors in the range of 33%, corresponding to 2900 annual full load hours. Typical duration curves are presented in figure 3.

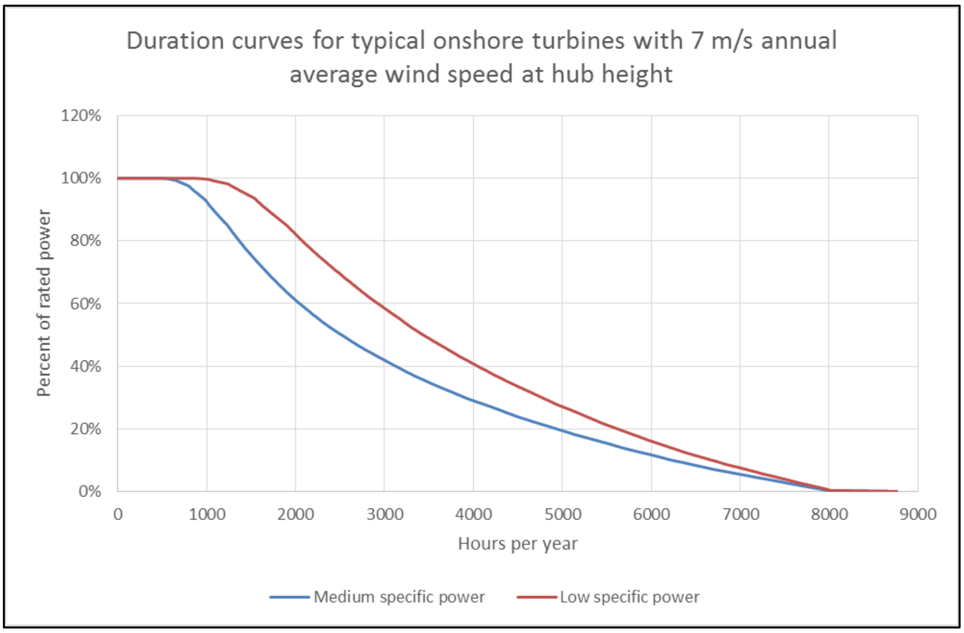


Figure 3: Duration curve for typical modern onshore wind turbines (> 2 MW) located in Denmark (DTU International Energy Report - Wind Energy, 2014). The two curves are based on the V117 3.3 MW (307 W/m^2) and V126 3.3 MW (265 W/m^2) wind turbines.

The annual energy output of a wind turbine is strongly dependent on the average wind speed at the turbine location. The average wind speed depends on the geographical location (with Northwestern Jutland being the windiest part of Denmark), the hub height, and the surface roughness. Hills and mountains also affect the wind flow, but as Denmark is very flat, the local wind conditions are normally dominated by the surface roughness. Also local obstacles like forest and for small turbines buildings and hedges reduce the wind speed like wakes from neighbor turbines reduces.

The surface roughness is normally classified according to the following table:

Roughness class	Roughness Length (m)[2]	Description
0	0.0002	Water
1	0.03	Open farmland
2	0.1	Partly open farmland with some settlements and trees
3	0.4	Forest, cities, farmland with many windbreaks

Table 1: Description of classification of surface roughness

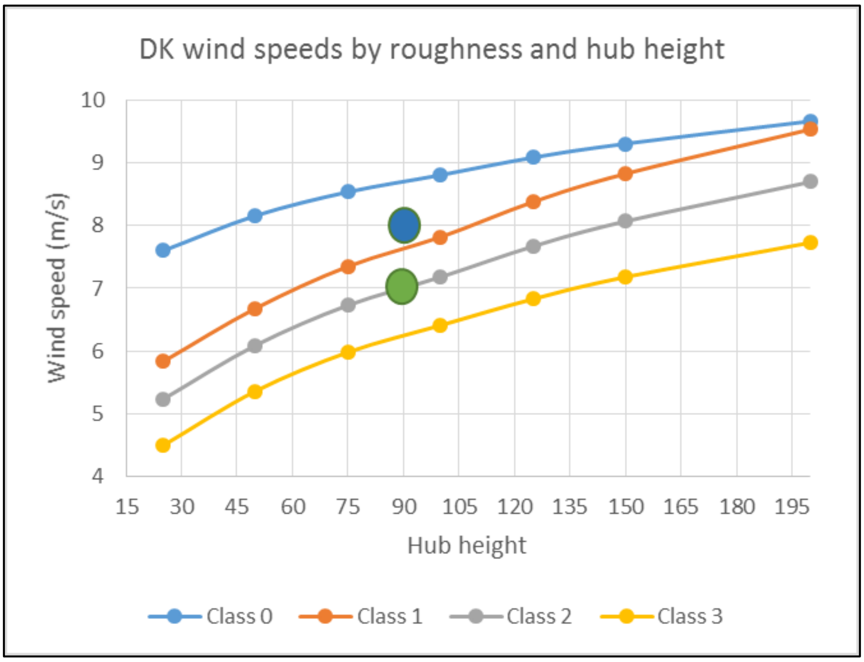


Figure 4: Annual average wind speeds as a function of hub height and roughness class for flat terrain. The green dot represents a typical modern inland site; the blue dot represents a typical coastal site. The typical hub height is 90 m.

Figure 4 shows the average wind speeds by hub height and roughness class for flat terrain. Onshore wind turbines installed in Denmark today typically have a hub height of 90 m. On a typical inland site the average wind speed is around 7 m/s, whereas on a typical coastal site the average wind speed is around 8 m/s. An increase in the average wind speed from 7 to 8 m/s results in a roughly 25% increase in annual energy production.

[2] The roughness length is the height above ground level, where average wind speed is 0. The wind speed variation with height is governed by the roughness length.

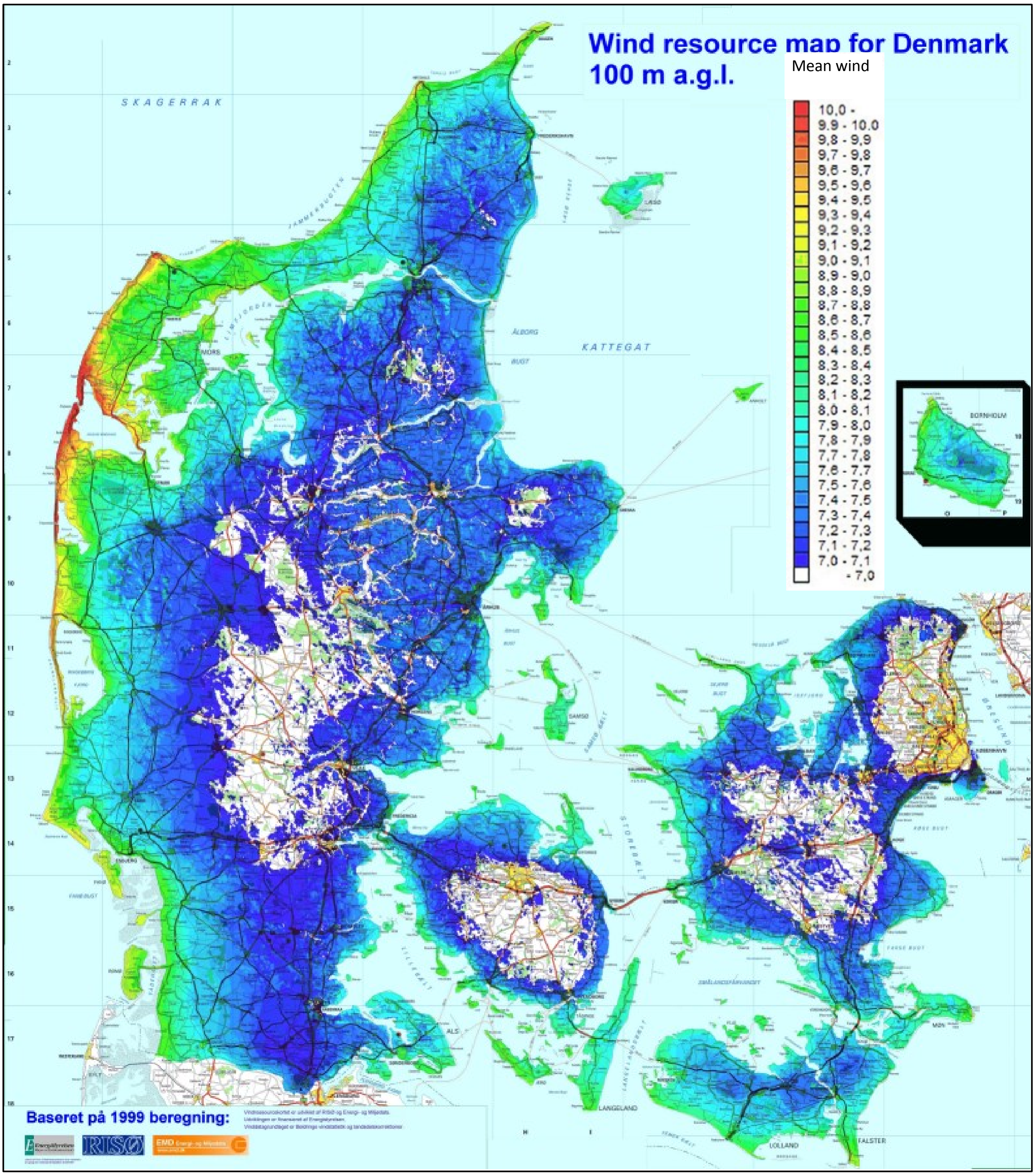


Figure 5: Wind resource map for Denmark in 200 m resolution, 100 m above terrain[3].

[3] The resource map is to a large extent calibrated with reference to the period 1985-95. This period has later turned out to have above-average wind speeds relative to long-term averages. Current estimates of long-term average wind speeds are roughly 3% lower than the wind speeds shown in the map.

The wind resource map for Denmark (figure 5) shows the regional differences. As seen, the regions close to the sea in dominating wind directions (west-southwest) that have the highest wind resource. This is a result of the low surface roughness in the upwind direction. The white areas have average wind speeds below 7 m/s at 100 m height above terrain.

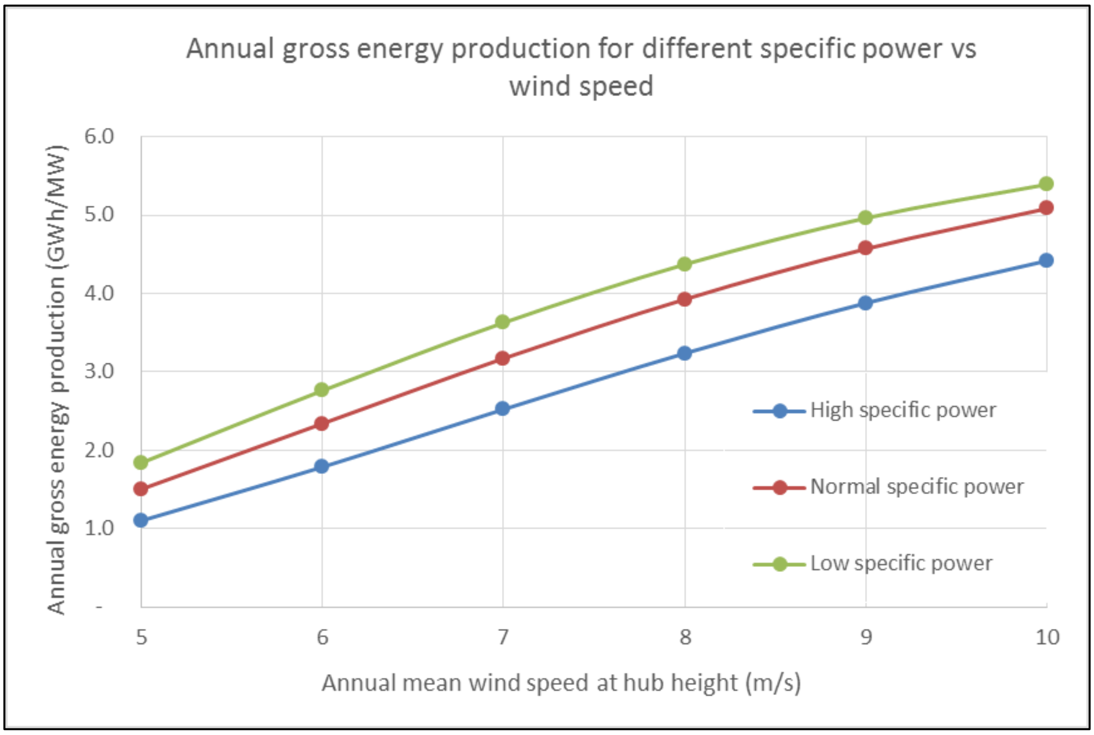


Figure 6: Annual gross Energy Production (AEP) as a function of mean wind speed at hub height. The examples in the figure are 3 MW with 90m rotor diameter, specific powers are 472 W/m2 called "high specific power" and 3.3 MW turbines with 112 m and 126 m rotor diameters, specific powers are 335 W/m^2 called "medium specific power" and 265 W/m^2 called "low specific power".

Figure 6 illustrates the importance of the annual mean wind speed as well as the specific power for the annual energy production (AEP). It is seen that the increase in AEP is almost linear with mean wind speed in the range from 6m/s to 9 m/s.

Typical capacities and development statistics

Onshore wind turbines can be categorized according to nameplate capacity. At the present time new installations are in the range of 2 to 6 MW. Another category is domestic wind turbines which is micro and small wind turbine in the range of 1 -25 kW, see separate paragraph on domestic turbines.

Two primary design parameters define the overall production capacity of a wind turbine. At lower wind speeds, the electricity production is a function of the swept area of the turbine rotor. At higher wind speeds, the power rating of the generator defines the power output. The interrelationship between the mechanical and electrical characteristics and their costs determines the optimal turbine design for a given site.

The size of wind turbines in Denmark has increased steadily over the years. Larger generators, larger hub heights and larger rotors have all contributed to increase the electricity generation from wind turbines. Lower specific capacity (increasing the size of the rotor area more than proportionally to the increase in generator rating) improves the capacity factor (energy production per generator capacity), since power output at wind speeds below rated power is directly proportional to the swept area of the rotor. Furthermore, the larger hub heights of larger turbines provide higher wind resources in general.

The average rated power of new onshore wind turbines in Denmark has increased by a factor of three since year 2000 (Figure 7 below). Although project developers consider larger turbines to be the most attractive, the increase in rated power is not constant, partly because some older projects with smaller turbines have been expanded with more (small) turbines, and partly because some projects are established with smaller turbines than the "optimal" size due to lack of space.

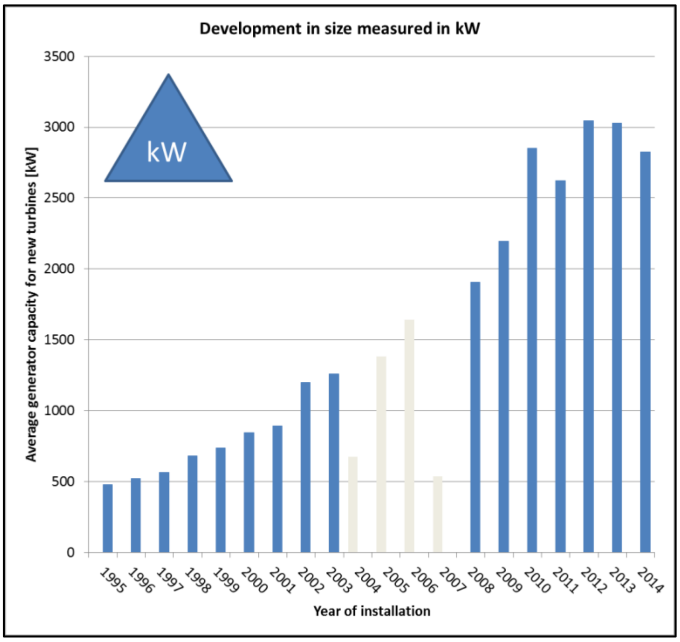


Figure 7: Average generator capacity for new turbines (rated power > 0.5 MW) [3]

In the same period the rotor diameters and hub heights have also increased as illustrated in figure 8 and 9.

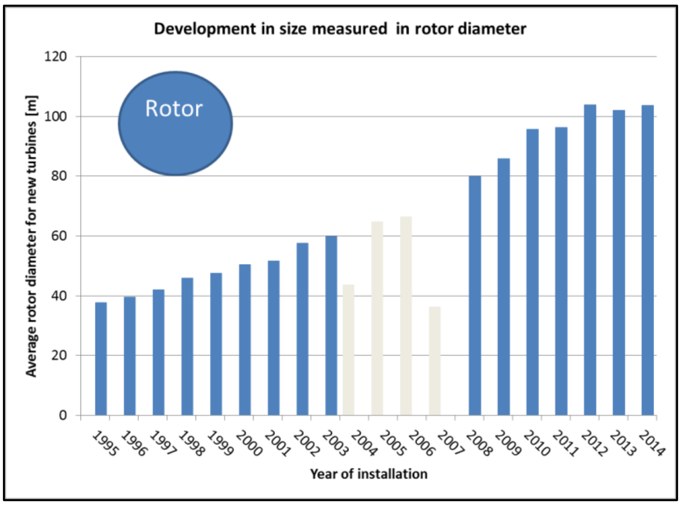


Figure 8: Average rotor diameter for new turbines (rated power > 0.5 MW) [3]

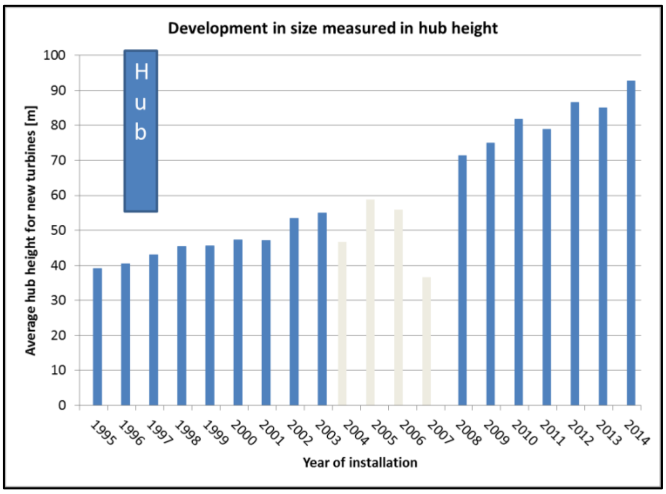


Figure 9: Average hub height for new turbines (rated power > 0.5 MW) [3]

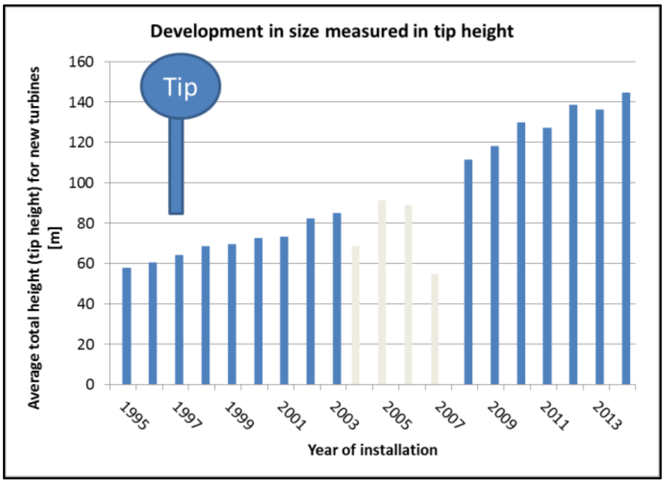


Figure 10: Average tip height for new turbines (rated power > 0.5 MW) [3]

The specific power has decreased for turbines installed in Denmark over the last 10 years. Formerly, turbines often had specific power values on the order of 400-450 W/m2. Since 2010 the average specific power has generally been less than 375 W/m2. In combination with improvements in turbine efficiency and an increase in average hub heights, this has resulted in increasing capacity factors. On average, capacity factors for Danish onshore turbines installed before 2000 were below 25% (corresponding to 2200 full load hours), while the average capacity factors for Danish onshore turbines installed after 2010 are typically in the order of 30-35% (corresponding to 2600-3100 full load hours). The trend towards larger rotors and lower specific power is global.

Due to current planning, environmental and civil aviation regulations wind turbines to be installed onshore in Denmark are generally limited to a maximum height of 150 m from the ground to the highest point i.e. rotor tip. In 2014 the average total height (tip height) was 145 m [4]. However, exemptions from the 150 m limit are granted for test sites. Elsewhere in Europe there is a strong trend towards approval of maximum heights above 150 m. An amendment of the Danish maximum height restriction could affect the future development in turbine dimensions.

Regulation ability and power system services

Electricity from wind turbines is highly variable because it depends on the actual wind resource available. Therefore, the regulation capability depends on the weather situation. In periods with calm winds (wind speed less than 4-6 m/s) wind turbines cannot offer regulation, with the possible exception of voltage regulation.

With sufficient wind resource available (wind speed higher than 4-6 m/s and lower than 25-30 m/s) wind turbines can always provide down regulation, and in many cases also up regulation, provided the turbine is running in power-curtailed mode (i.e. with an output which is deliberately set below the possible power based on the available wind).

In general, a wind turbine will run at maximum power according to the power curve (c.f. figure 10) and up regulation is only possible if the turbine is operated at a power level below the power actually available. This mode of operation is technically possible and in many countries, turbines are required to have this feature. However, it is rarely used, since the system operator will typically be required to compensate the owner for the reduced revenue [5].

Wind turbine generation can be regulated down quickly and this feature is regularly used for grid balancing. The start-up time from no production to full operation depends on the wind resource available.

New types of wind turbines (DFIG and converter based) also have the ability to provide supplementary ancillary services to the grid such as reactive power control, spinning reserve, inertial response, etc. However, these supplementary ancillary services from wind turbines are seldom utilized in Denmark, due to a lack of economic incentives. Older types of wind turbines typically deployed in Denmark before 2008 consume reactive power and can have a negative influence on voltage stability.

Advantages/disadvantages

Advantages:

- No emissions to air from operation
- No emission of greenhouse gasses from operation
- Stable and predictable costs due to low operating costs and no fuel costs
- Modular technology allows for capacity to be expanded according to demand avoiding overbuilds and stranded costs
- Short lead time compared to most alternative technologies

Disadvantages:

- High capital investment costs
- Variable energy resource
- Moderate contribution to capacity compared to thermal power plants
- Need for regulating power
- Visual impact and noise

Environment

Wind energy is a clean energy source. The main environmental concerns are visual impact, flickering from rapid shifts between shadow and light when turbine is between sun and settlement, noise and the risk of bat or bird-collisions.

The visual impact of wind turbines is an issue that creates some controversy, especially since onshore wind turbines have become larger.

Flickering is generally managed through a combination of prediction tools and turbine control. Turbines may in some cases need to be shut down for brief periods when flickering effect could occur at neighbouring residences.

Noise is generally dealt with in the planning phase. Allowable sound emission levels are calculated on the basis of allowable sound pressure levels at neighbours. In some cases it is necessary to operate turbines at reduced rotational speed and/or less aggressive pitch setting in order to meet the noise requirements. Noise reduced operation may cause a reduction in annual energy production of 5-10%. Despite meeting the required noise emission levels turbines sometimes give rise to noise complaints from neighbours. In 2013 it was decided to investigate in detail how wind turbines and especially noise from wind turbines influence human health. A conclusion on the work is expected by end of 2015 [6]. A recent Canadian literature study concludes that wind turbines might cause annoyance at the neighbours, but no causal relation could be established between noise from wind turbines and the neighbour's health [7].

The risk of bird collisions has been of concern in Denmark due to the proximity of wind turbines to bird migration routes. In general, it turns out that birds are able to navigate around turbines, and studies report low overall bird mortality but with some regional variations [8].

The environmental impact from the manufacturing of wind turbines is moderate and is in line with the impact of other normal industrial production. The mining and refinement of rare earth metals used in permanent magnets is an area of concern [2, 9, 10].

The energy payback time of an onshore wind turbine is in several studies calculated to be in the order of 3-9 months [11, 12].

Life-cycle assessment (LCA) studies of wind farms have concluded that environmental impacts come from three main sources:

- bulk waste from the tower and foundations, even though a high percentage of the steel is recycled
- hazardous waste from components in the nacelle
- greenhouse gases (e.g. CO2 from steel manufacturing and solvents from surface coatings)

Research and development perspectives

R&D potential: [2, 13]

- Reduced investment costs resulting from improved design methods and load reduction technologies
- More efficient methods to determine wind resources, incl. external design conditions, e.g. normal and extreme wind conditions
- Improved aerodynamic performance
- Reduced operational and maintenance costs resulting from improvements in wind turbine component reliability
- Development in ancillary services and interactions with the energy systems
- Improved tools for wind power forecasting and participation in balancing and intraday markets
- Improved power quality. Rapid change of power in time can be a challenge for the grid
- Noise reduction. New technology can save the losses by noise reduced mode and possible utilize good sites better, where the noise set the limit of number of turbines
- Public acceptance
- Repowering strategies, like when it is feasible to repower for society and for investors – subsidy schemes must support optimal solutions
- Storage can improve value of wind power much, but is expensive at present

Examples of best available technology

Presently only Siemens and Vestas have commercially approved turbines suitable for Danish onshore projects. The wind turbines offered have rated power in the 2–4 MW range and rotor diameters of 80-130 m. Hub heights are typically in the range of 80-100 m.

Prediction of performance and cost

Cost breakdown of total capital costs for onshore wind turbines

The capital costs of onshore wind power projects are dominated by the cost of the wind turbine itself. Figure 11 shows the breakdown of an average project in Denmark. The cost of grid connection is covered by the Transmission System Operator (TSO) and does not appear in the cost breakdown. Grid connections are generally 3 to 7 % of total investment costs.

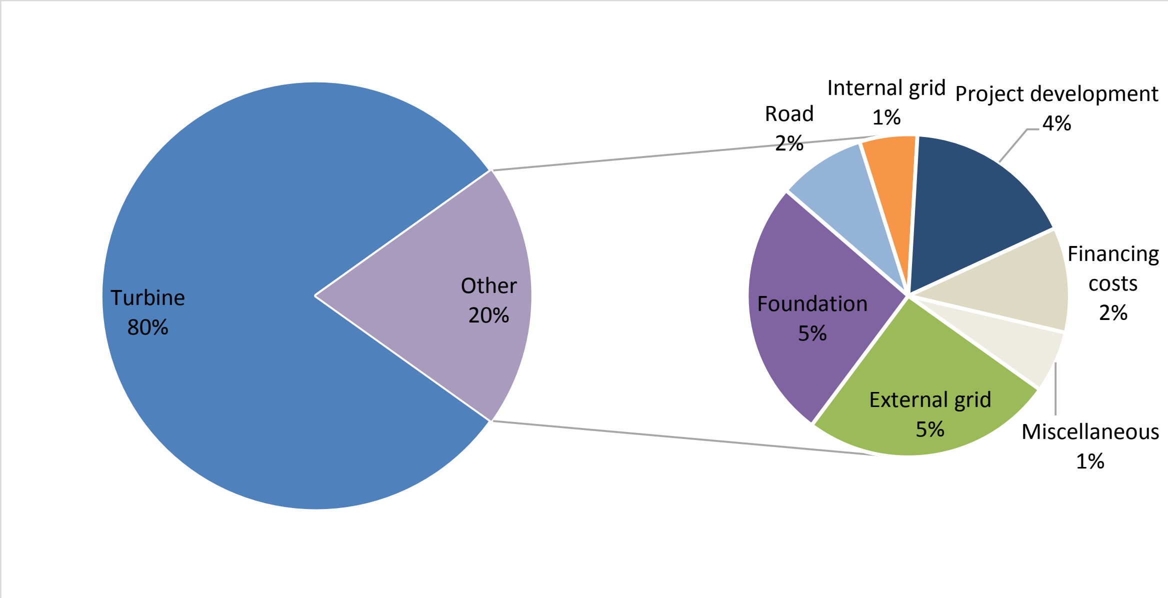


Figure 11 Breakdown of capital costs for a typical wind power project in Denmark[4] [14]

Not included in the cost breakdown are the following supplementary project costs:

- Cost of land
- Compensation for loss of value for nearby settlements (Værditabsordningen)
- Purchase of existing turbines to be dismantled at site or nearby
- Purchase of nearby settlements to free space for the project

These costs are highly variable from project to project and can vary from 0% to round 25% of the total investment, depending on the local situation. These costs will be on top of the costs shown in figure 11.

There are four major components in operation and maintenance costs for wind turbines in Denmark: service agreement, insurance, land rent/administration and repairs not covered by service agreement. Each cost component accounts roughly for 25% of Operating and Maintenance (O&M) costs over the lifetime of a wind turbine [4]. For more recent projects the trend is that the service agreement cover more and insurance and repair cost will represent a lower percentage.

A major part of the most recent onshore wind turbines are delivered with long term service contracts (more than 10-15 years) provided by the turbine manufacturers and a large part of the service/maintenance costs is known upfront. However, it is difficult to estimate the costs for repairs

[4] The cost breakdown is based on recent projects published trough the "køberetsordning", where neighbours to new projects have the right to purchase 20% of the projects at actual cost of the projects. Thereby the detailed cost breakdown must be made public available.

not covered by the service agreement, and even with long-term service agreements unforeseen cost may occur [15].

A study based on data for 2009 reports the expected lifetime costs for O&M for wind turbines installed in Denmark to be approximately €12/MWh (2015 prices) [4]. This is in accordance with the latest experience from the Danish Wind Turbine Owners association, which estimates a lifetime O&M-cost of 11 €/MWh (2015 prices) [15].

Cost and production dependence of hub height and specific power

To identify main drivers for future technology a deeper look is taken on how the production changes relative to the cost of the turbines by different parameter variations.

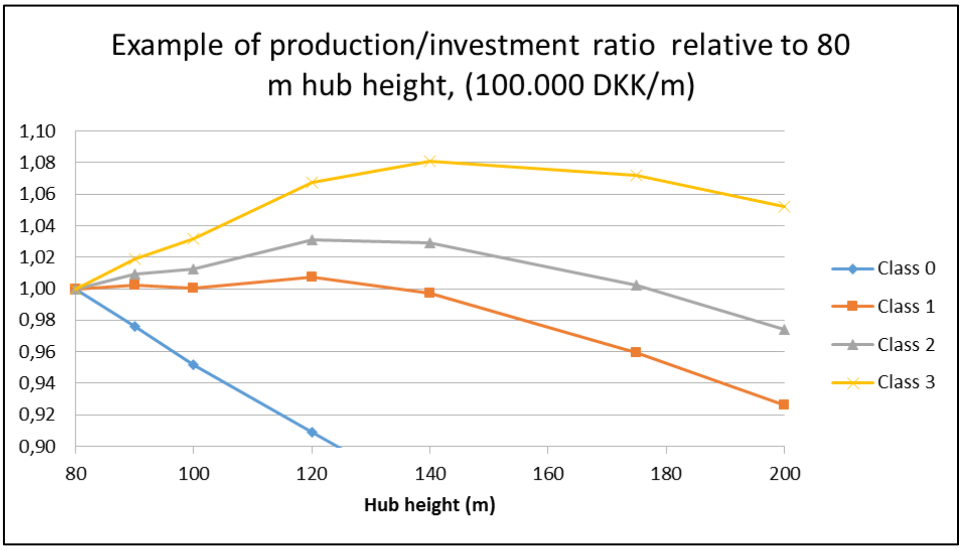


Figure 12: The production increase relative to the investment cost based on current available Vestas turbines. By increasing height, costs are extrapolated using DKK 100.000 per m hub height increase; the rotor area is kept constant.

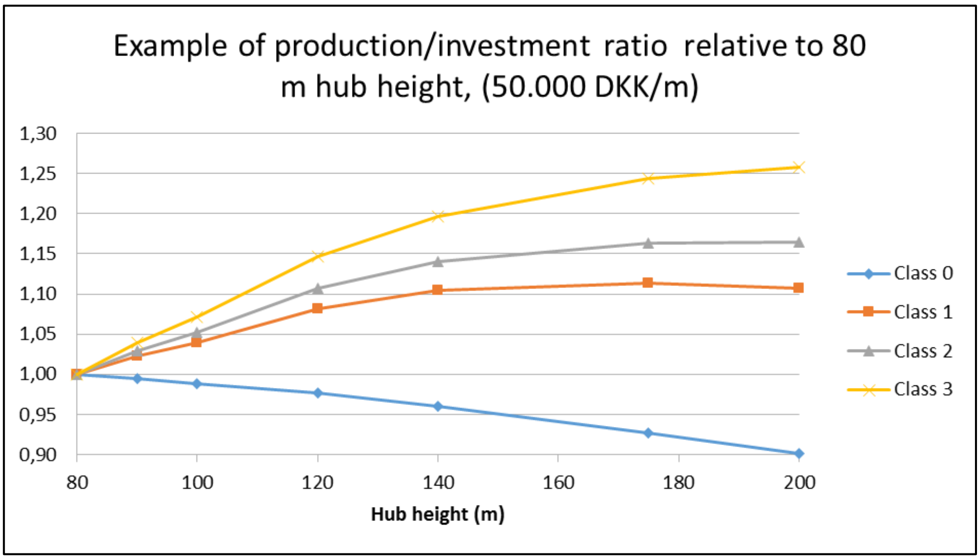


Figure 13: Similar, the production increase relative to the investment cost based on current available Vestas turbines, for increasing height, where costs are extrapolated using DKK 50.000 per m hub height increase, the rotor area is kept constant.

Figure 12 and 13 demonstrate that except for in the offshore roughness class 0 hub heights above today's standard would lead to improved cost efficiency. In countries like Germany and Sweden, the improvements are generally at the higher end due to a higher average roughness class, and in the recent years 140m hub height are becoming common in commercial projects.

While the assumed cost increase of DKK 50-100.000 per meter hub height increase is within the range seen of present technologies, many other factors contribute to the cost increase with height, such as the specific tower technology, the project location relative to manufacturing, and the available cranes. Consequently, the cost increase will not be linear with height (as assumed in the figures), and the figures should be taken as a general illustration of the potential cost reductions by increased hub heights.

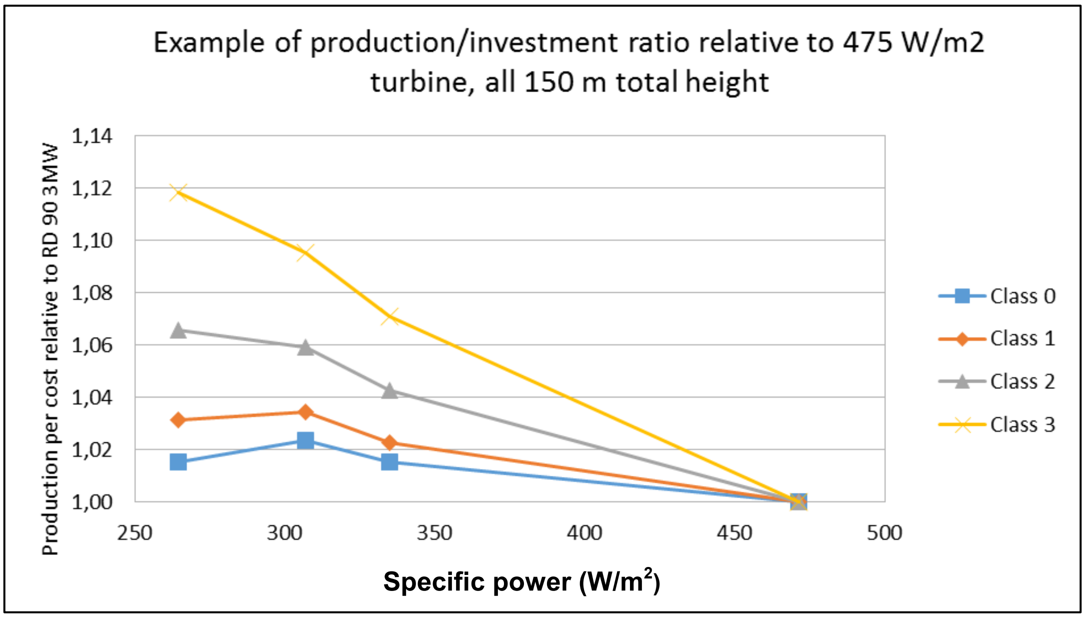


Figure 14: The production relative to the investment cost based on current available Vestas turbines for different rotor areas, generator size is 3-3.3 MW for all (= different specific power).

Cost optimization leads to smaller generators for the same rotor area with limited loss of production. In order to support this optimization the subsidy system is now based more on rotor area and less on generator size.

Figure 14 illustrates the potential benefits from reduction of the specific power. Modern turbines with a specific power of less than 300 W/m^2 have up to 12% improvement in energy production per cost when comparing a typical turbine of 2010 vintage (90 m rotor; 3 MW; rated power 475 W/m^2). If the improvement due to hub height increase would be included, even higher improvements would be seen.

To some extent the average capacity factors of onshore turbines installed since 2010 are affected by noise reduced operation due to noise regulations. Typically, noise reduced operation results in around 5% lower annual production than if non-noise reduced operation was possible. The noise reduced mode will typically reduce 5-10% with the Danish regulations, whereas higher reductions are seen in other countries.

Prediction of cost in 2015

The investment cost of wind turbines is expressed as investment per installed MW. This should however not stand alone when assessing the cost of the production of electricity from wind turbines. As mentioned before, the increase in hub height and rotor size of the turbine incurs additional investment costs per MW, but also increases the production per MW.

The development in the cost of wind turbines per installed MW and the numbers of full load hours are shown in figure 15 and 16. Costs increased between 2002 and 2008. This was due to increased size and technical complexity of wind turbines and increased costs of steel, other raw materials and labour during this period, increased mark-ups by wind turbine manufacturers, and the effects of supply chain shortages for wind turbines and key components.

At the same time the electricity production per MW (annual full load hours) increased due to increases in the size and other technological improvements.

Figure 15 illustrates how the energy production (annual full load hours) and the investment cost has developed since 1995. In figure 15 it is seen that in the recent years (2008-2014) the increase in energy production has been higher than the increase in investment costs.

The year-by-year variations are mainly a reflection of the sensitivity to the wind resource of actual project, rather than a year-to-year change in the technology used. Turbines installed during the period 2010-12 have the highest number of full load hours. This is probably most related to the fact that the majority of the turbines installed during this period are located in western Jutland which has the best wind resources in Denmark.

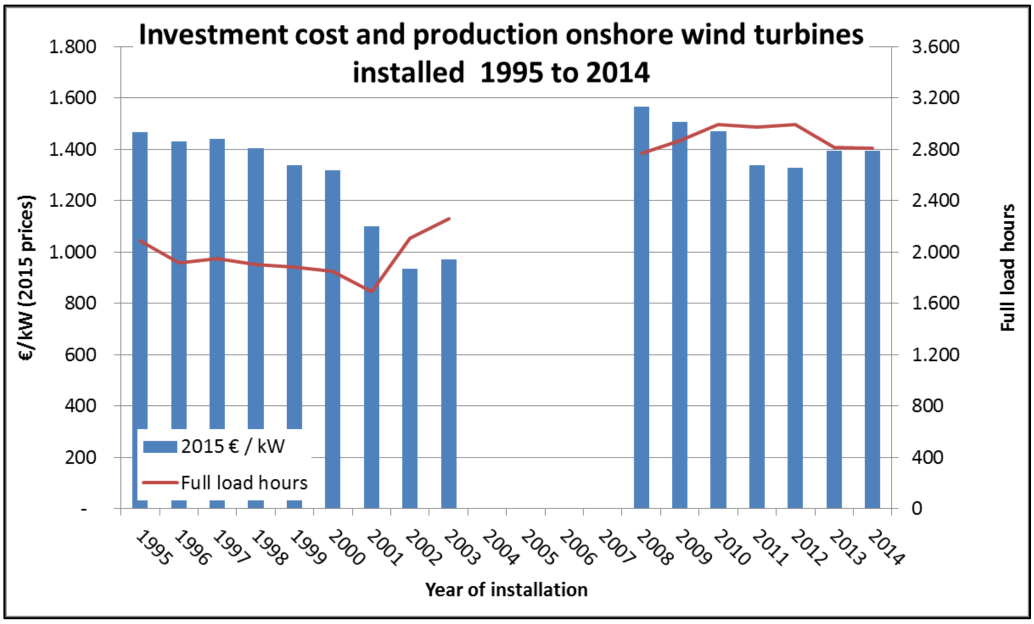


Figure 15: Development in investment cost (2015 price level) and average production (full load hours) for onshore turbines > 0.5 MW by installation year based on 2014 production[5] [3, 16, 2]

[5] For turbines installed in 2014; only turbines with more than 5 months of production is included and the production is normalized to a full year.

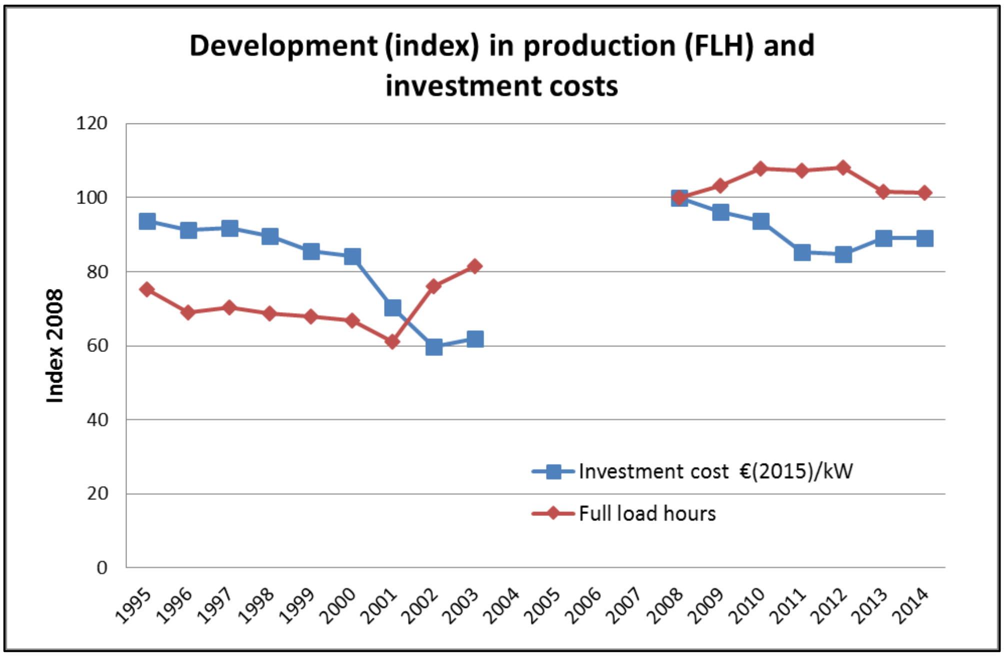


Figure 16: Development (index 2008=100) in investment cost (2015 price level) and average production (full load hours) for onshore turbines > 0.5 MW by installation year based on 2014 production [3, 16, 2]

Data from the most recent projects, which has been agreed 2013 and 2014 showed that the average investments prices for these projects are approximately 1,2 €/kW [14].

Prediction of cost in the period from 2015 to 2050

Onshore wind turbines can be seen as off-the-shelf products, but technology development continues at considerable pace, and the cost of energy has continued to drop. While price and performance of today's onshore wind turbines are well known, future technology improvements, increased industrialization, learning in general and economics of scale are expected to lead to further reductions in the cost of energy. Consequently, despite the fact that more than 350.000 MW of onshore wind has been deployed worldwide, onshore turbines are categorized as development category 3; *Commercial technologies with moderate deployment*, with a significant development potential and a considerable level of uncertainty related to future price and performance.

The annual specific production (capacity factor/full load hours) is expected to continue to increase; this is illustrated in figure 17. The increase in production is mainly expected to be due to lower specific power, but also increased hub heights, especially in the regions with low wind, and improvement in efficiency within the different components is expected to contribute to the increase in production.

The predictions of cost reductions are made using the learning curve principle. Learning curves expresses the idea that each time a unit of a particular technology is produced, some learning accumulates which leads to cheaper production of the next unit of that technology. Therefore a reduction in investment cost is expected. Research and development is also expected to influence the cost and efficiency.

According to the report ”Renewable Power generation cost in 2014 Electricity”, IRENA 2014 [17] the cost of onshore wind turbines has reduced by 4-25% from 2010 to 2014, with large geographical variations. At the same time, the cumulative installed capacity (CIC) increased by 80%. The largest cost reductions have been realized in China and India. Hence, the learning rate for the investment cost for onshore wind turbines is set to approximately 10%. In addition, it is assumed that for each of the periods 2015-2020, 2020-2030 and 2030-2050 the cumulative installed capacity (CIC) will be almost doubled. The resulting development in cost is illustrated in figure 16. At the same time it is assumed that the production (FLH) will increase due to a reduction in the specific power and technical improvements. It is expected that the production (FLH) increase 1.5 % from 2015 to 2020 and from 2020-2030 and 3% from 2030-2050.

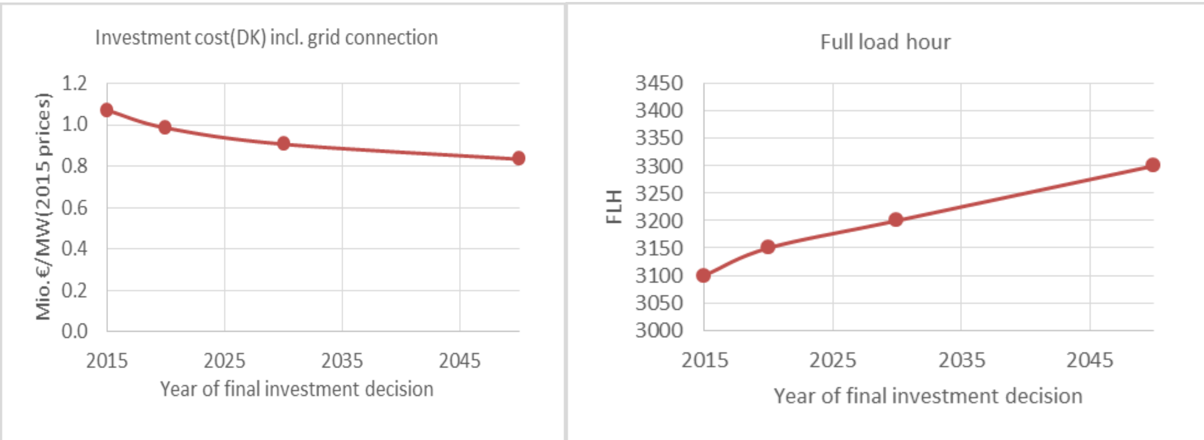


Figure 17: Expected development in investment costs and in production (full load hours (FLH)) for on shore wind turbines located in DK.

The predicted development in costs and full load hours leads to a decrease in levelized cost for produced electricity (LCOE) of approximately 11% in each period, resulting in approximately 30% lower LCOE in 2050 than in 2015.

This is in accordance with development the same report [17] the weighted LCOE has fallen 7-12 % from 2010 to 2014. At the same time, the cumulative installed capacity (CIC) increased by 80%. This is equivalent to a learning rate for LCOE in the range of 9-15%.

Uncertainty

As mentioned before the onshore wind technology is quite mature. However, due to improvements in technology and cost reductions, the prediction of future reductions in cost of energy is affected by some uncertainty. Especially it must be noted regarding cost development that many other factors than learning curves can affect the cost development, such as the market situation, costs of rare earth minerals, iron, cobber etc. The development in full load hours is affected by the geographic locations of the majority of the turbines to be installed, and it can be increased considerably if larger total heights will be accepted in future.

Future demands, onshore

In the future it could be expected that the onshore wind turbines will be met with

- Higher environmental protection demands like noise or reduced visibility of aviation light marking or less visibility in general (colouring).
- More demands on participation in grid regulation.

Additional remarks

Recently, the technical lifetime of a wind turbine has been assumed to be 20 years. Recent investigations and real-life experiences indicate longer technical lifetimes [18, 19, 20]. For turbines installed in the coming years lifetimes of 25 years are expected. In the longer term (2030-2050) lifetimes of up to 30 years could be expected.

Domestic wind turbines (microwind or small-wind turbines)

Domestic wind turbines are micro-wind or small-wind turbines with a capacity up to 25 kW. According to the regulation in Denmark domestic wind turbines (up to 25 kW) must be located in close proximity of a house (within 20 m from building) [21], and must follow the same demands for noise as large turbines [22].

The capacity factor of small wind turbine varies a lot dependent on the local conditions. The turbines are often located close to buildings and trees, which will reduce the annual production from the turbines. The specific power will as for the larger turbines have an impact on the capacity factor and so have the relative low hub height. An average capacity factor of 18% (approximately 1600 full load hours) is assumed in this study. There are no public available statistics for confirmation of this though, while domestic turbines only report sold power whereas in-house consumption directly from turbine is not registered.

Data sheets

Technology	Large wind turbines on land									
Year of final investment decision	**2015**	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	3.5	3.5	4	5	2.0	6.0	1.5	8.0	A1	3
Average annual full-load hours	3100	3150	3200	3300	2000	4000	2000	4500	A, L	3
Forced outage (%)	3.0%	2.5%	2.0%	1.5%	1.0%	5.0%	1.0%	5.0%	B	4
Planned outage (%)	0.3%	0.3%	0.3%	0.3%	0.1%	0.5%	0.1%	0.5%	C	4
Technical lifetime (years)	25	27	30	30	25	35	25	40	D	14
Construction time (years)	1.5	1.5	1.5	1.5	1	3	1	3	E	4
Space requirement (1000m2/MW)	---	---	---	---	---	---	---	---	F	
Regulation ability										
Primary regulation (% per 30 seconds)									G	
Secondary regulation (% per minute)									G	
Financial data										
Nominal investment (M€/MW) incl grid connection	1.07	0.99	0.91	0.83	0.9	1.1	0.7	1.0	H	16, 2, 4
Nominal investment (M€/MW) excl. grid connection (5% of nom. Investment)	1.02	0.94	0.86	0.79	0.8	1.0	0.6	0.9	I, M	16, 2, 4
- of which equipment	75%	75%	75%	75%	70%	80%	70%	80%		4
- of which installation	25%	25%	25%	25%	20%	30%	20%	30%		4
Fixed O&M (€/MW/year)	25,600	23,900	22,300	21,200	21,510	26,290	16,960	25,440	J,N	
Variable O&M (€/MWh)	2.8	2.5	2.3	2.1	2.3	2.8	1.7	2.5	J,N	4, 15, 18
Technology specific data										
Rotor diameter	120	120	130	150	90	130	100	150	K	4
Hub height	90	90	100	110	85	120	85	150		4
Specific power (W/m2)	309	309	301	283	270	350	250	350		
Average capacity factor	37%	37%	38%	39%	23%	46%	23%	51%		4
Average availability (%)	97%	97%	98%	98%	99%	95%	99%	95%		4

Notes:

A1 The capacity is set to 3.5 MW in 2015 and 2020 based on data of current wind turbines (Stamdataregisteret) and under the anticipation that the maximum height will not exeed 150m before 2020. From 2030 a slight increase in generator size, and hub height is assumed.

A The full load hours (annual produktion (MWh) per installed power (MW)) depending on the actual location of the wind farm, wake losses and technological characteristics of the individual turbine. The value is an average for the expected locations of the wind farms. FLH also depends on wake losses, noise reduction and technological characteristics of the individual turbine. The level for 2015 and 2020 is based on data for existing onshore turbines of the same configuration (Stamdataregisteret) and recent prospects for onshore projects published in relation to Køberetsordningen. For 2030 and 2050 a slight increase is assumed based on decrease in specific power and increase in hub height.

B Modern turbines has typically higher forced outage than older smaller turbines had when they were newer due to more complex technology.

C Planned outage is typically 1-2 service visits a year, with a maximum duration of one work day, but there can also be planned outage due to shadow flicker stop or sector management (protect turbines at given wind speeds and directions, where they are dense spaced).

D The life time depends on the wind conditions; average annual speed and turbulence, relative to the design class of the turbine

E The construction time is the periode from FID to commissioning. But from first "dig" to turbines are in operation less than ½ a year is needed for smaller wind farms (clusters), where the similar periode for larger wind farms will be longer. The planning time from idea to construction starts will typically be 2-3 years, but can be essentially more if permitting problems occour.

F An area of around 50 m x 50 m is needed for a modern wind turbine. Another way of defining the "area use" could be the noise zone, which ranges up to 600-800 m from the wind turbine in worst case.

G Wind turbines can be downward regulated within very short time and can therefore (if the wind is blowing) be used in both the primary and secondary downward regulation.

H 2015 Investment cost based on a number of recent prospects for projects published in relation to Køberetsordningen. The price is excl. land rent, buy out of existing older turbines and possible buy out of settlements within wind farm area which are highly variable costs.

I The grid connection is sozialized in Denmark and can be subtracted from the given nominal investment seen from the project owner

J 75 % of the total yearly O&M costs are assumed to be fixed cost and 25 % are assumed to be variable cost.

K Currently only turbines up to 150 m total height is installed commercially in Denmark because of strict demands to higher turbines. No change in the national regulation is assumed until after 2020. Some test sites allow for larger turbines. Aboard e.g. in Germany windmills with at total higher of 200 m is installed today.

L It is expected that the production (FLH) increase 1.5 % from 2015 to 2020 and 2020-2030 and 3% in from 2030-2050

M It is predicted that the investment cost for on shore turbines will be reduced 8% in each period; 2015-2020, 2020-2030 and 2030-2050.

N It is predicted that the cost of O&M for on shore turbines will be reduced 8% in each period; 2015-2020, 2020-2030 and 2030-2050.

Technology	**Small wind turbines, grid connected (< 25 kW)**									
Year of final investment decision	**2015**	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	< 0,025				0.005	0.025	0.005	0.025		
Average annual full-load hours	1600	1600	1600	1600	1000	2300	1000	2300	A,J	
Forced outage (%)	3%	3%	3%	3%	2%	10%	2%	10%		
Planned outage (%)	0.3%	0.3%	0.3%	0.3%	0.1%	0.5%	0.1%	0.5%	B	
Technical lifetime (years)	20	20	20	20	---	---	---	---		
Construction time (years)	1	1	1	1	0.5	1.5	0.5	1.5		
Space requirement (1000m2/MW)	0.8	0.8	0.8	0.8	---	---	---	---	C	
Regulation ability										
Primary regulation (% per 30 seconds)	---	---	---	---	---	---	---	---	D	
Secondary regulation (% per minute)	---	---	---	---	---	---	---	---	D	
Financial data										
Nominal investment (M€/MW) incl grid connection	4.0	3.8	3.6	3.4	3.0	6.0	3.0	6.0	E/F	
Nominal investment (M€/MW) excl. grid connection (5% of nom. Investment)	90%	90%	90%	90%	85%	95%	85%	95%	E/F	
- of which equipment	10%	10%	10%	10%	15%	5%	15%	5%	E/F	
- of which installation	100000	95000	90000	85000	---	---	---	---	G	
Fixed O&M (€/MW/year)	---	---	---	---	---	---	---	---		
Variable O&M (€/MWh)	4.0	3.8	3.6	3.4	3.0	6.0	3.0	6.0	E/F	
Technology specific data										
Rotor diameter	8	8	8	8	4	14	4	14	H	
Hub height	18	18	18	18	14	18	14	18	H	
Fixed O&M (€/unit)	540	540	540	540	350	700	350	700	E/F	

Notes:

A The annual production is very sensitive to conditions at the actual site. Values outside the range is observed.

B The maintenance normally consists of 1 -2 annual service visits.

C An area of around 5 m x 5 m is needed for at small wind turbine. The real "area use" is the noise zone, which ranges up to 100 m from the wind turbine in worst case.

D Not considered relevant for small domestic turbines.

E Based on information from manufacturers and resellers. The

F The prices depends significantly on turbine size (5 kW - 6 M€/MW; 10 kW - 4 M€/MW ; 25 kW - 3 M€/MW)

G The service cost is assumed fixed to 100€/kW/y.

H Domestic turbines have a maximum total height of 25 m according to Danish regulations.

J No development in the capacity factor is expected, because no changing in the size limitation (legislation) is expected. And because location is crucial and one must expect the turbines is put up at the best positions already. But change in legislation i

References

[1] Information's from expert workshop held by DEA 27-4-2015.

[2] DTU International Energy Report - Wind Energy, DTU, 2014.

[3] Master data register of wind turbines at end of December 2014, Danish Energy Agency, 2015.

[4] Nielsen, P. et. al., Vindmøllers økonomi EUDP projekt 33033-0196, 2010.

[5] Fixed Speed and Variable-Slip Wind turbines Providing Spinning reserves to the Grid, NREL, 2013.

[6] Sundhedsundersøgelsen [Online]. Available: http://vindinfo.dk/sundhedsundersøgelse.aspx.

[7] M. e. al, Wind Turbines and Health, Journal of Occupational and Environmental Medicine*,* årg. 56, nr. 11, November 2014.

[8] Vindkraftens påverkan på fåglar och fladdermöss, Naturvårdsverket, 2011.

[9] Life Cycle Assessment of Electricity Production from an onshore V112-3.3 MW Wind Plant, June 2014, Vestas Wind Systems A/S.

[10] Environmental Product Decalaration - SWT-3.2-133, siemens.dk/wind, 2014.

[11] S. Krohn, The Energy balance of modern turbines, December 1997.

[12] Karl R. Haapala and Preedanood Prempreeda, Comparative life cycle assessment of 2.0 MW wind turbines, Oregon State University, USA, 2014.

[13] Increasing the Owner's Value of Wind Power Plants in Energy Systems with Karge

[14] Information from Energinet.dk based on analyses of resent installed projects (2013-14), published under "Købsretsordningen", 2015.

[15] Når all-inclusive service alligevel ikke dækker alt, Naturlig Energi, nov. 2014.

[16] Schwabe, P., Lensink, S. & Hand, M., IEA Wind Task 26: Multi-national case study of the financial cost of wind energy, 2011.

[17] Renewable Power Generation Cost in 2014 Electricity, Irena, 2014.

[18] Hvor længe holder en mølle, Naturlig Energi, januar 2012.

[19] Green, Staffell, How does wind farm performance decline with age?, Renewable Energy 66, 2014.

[20] Vindmøller lever længere end forventet, November 2010. [Online]. Available: http:/www.ing.dk/artikel/vindmoller-lever-laengere-end-forventet-114251.

[21] Vejledningsnotat om planlovens regler ved opstilling af husstandsmøller, Naturstyrelsen, 2012.

[22] Bekendtgørelse om støj fra vindmøller - BEK nr. 1284 af 15-12-2011, Retsinfo, 2011.

[23] Energiaftalen af 22. marts 2012, http://www.efkm.dk/energi-forsynings-klimapolitik/dansk-energi-forsynings-klimapolitik/energiaftale, 2012.

[24] Minivindmøller i København, Ea Energy Analysis for Copenhagen Municipality, November 2009.

21 Wind Turbines, Offshore

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Author: Mads V. Sørensen / Per Nielsen (EMD)

Publication date

August 2016

Amendments after publication date

Date	Ref.	Description
June 17	Prediction of cost in 2015 and 2020 Prediction of cost from 2020 to 2050 Data sheet	Financial data (Investment cost and O&M) updated

Note to Amendments June 2017:
The winning price in the tenders for the offshore wind farms in Denmark has decreased substantially from 2012 to 2016. The same trend has been seen in e.g. the Netherlands and Great Britain. The reduction in prices is substantially larger than what can be explained by the cost reduction predicted (in the Technology Catalog). Therefore, the financial data for offshore wind has been updated (June 2017). Changes are made in the sections *"Prediction of costs in 2015"* and in the datasheet.

The update comprises investment costs (CAPEX) and operating & maintenance costs (OPEX), i.e. financial parameters. In terms of data for the more technical parameters such as mill size, full load hours, lifetime and the like existing data are still considered valid.

There are several reasons for the reduction in the winning bids. The costs of the wind turbine technology itself, as well as for installation, operation and maintenance have fallen sharply in recent years. In general, more experience has been gained in this area, making the collaboration between the different players on the market more efficient. Moreover, there are better opportunities for optimizing project plans and the volume of the offshore wind market. In addition, interest rates are low and technological and economic risks are assessed lower by investors, therefore low returns are accepted and competition has been increasing. Expectations for the electricity price after expiry of the grant period and other possible income from e.g. certificates of origin also affect the bid price.

Qualitative description

Brief technology description

For a detailed technical description see the previous chapter on wind turbines, onshore.

The basic operating principles of offshore wind turbines are the same as for onshore turbines, although modifications are required to make the turbines suitable for deployment offshore. The corrosive offshore environment resulting from the high levels of salt and moisture in the air leads to additional requirements for electrical and mechanical components. Since the world's first offshore wind project at Vindeby in Denmark, offshore turbines have been equipped with air conditioning systems to protect the sensitive electronics inside the units, and with North Sea-grade protective paint to protect the external steel structures.

Foundations for offshore turbines are subject to more complex load conditions than onshore foundations. They must be designed to survive the harsh marine environment and the impact of large waves and ice. These factors and the cost of installation mean that they are more expensive than onshore foundations for turbines of similar size.

Until now, offshore wind farms have been installed on four different types of foundation: monopile, gravity, jacket and tripod structures. Today, monopiles and jackets are the most common foundation types. The choice of which foundation type to use depends on the local sea-bed conditions and the water depth.

Technological innovations such as suction bucket foundations and floating foundations are being investigated and may have the potential to reduce the overall cost in the future. Suction bucket foundations are mainly suitable when the sea bed is sand, but have the advantage of smaller material consumption and lower decommissioning cost. Floating constructions can be designed to be well suited for large serial production, and they are the only solution for deep waters. These technologies are not currently deployed on a commercial basis.

Offshore wind farms are typically built with large turbines in considerable numbers. The most recent offshore wind farms built or under construction in Denmark have capacities of 200-400 MW. Projects of up to 600 MW are being planned in Danish waters. In UK, Netherlands and German waters offshore wind farms of several thousand MW are being developed.

Offshore wind turbines have built-in transformers delivering 33 kV to the array cable system in the wind farm. In traditional offshore wind farms the array cables are connected to a transformer station in the wind farm. Here the voltage is transformed to 150 kV or 220 kV for export to the onshore grid. In nearshore wind farms the array cables are often connected to an onshore transformer station.

66 kV turbine transformers, switchgear and cables are becoming commercially available, and the wind farm voltage level of new projects is generally expected to be raised from 33 kV to 66 kV. The higher voltage level will reduce cable losses and the total lifecycle costs and thereby reduce the cost of energy.

Offshore wind power projects include both traditional offshore projects and nearshore projects. In this publication near-shore wind farms are defined as projects having grid connection at the wind farm voltage level, i.e. connecting to an onshore transformer station.

The offshore wind resource increases with distance to the shore (figure 1) and as a result wind farms far from the shore will generally have higher capacity factors than nearshore wind farms. However, due to the simplified grid arrangement with no offshore substation, and due to shallow waters and shorter distances to service hubs, nearshore wind farms have lower cost levels for both investment and O&M.

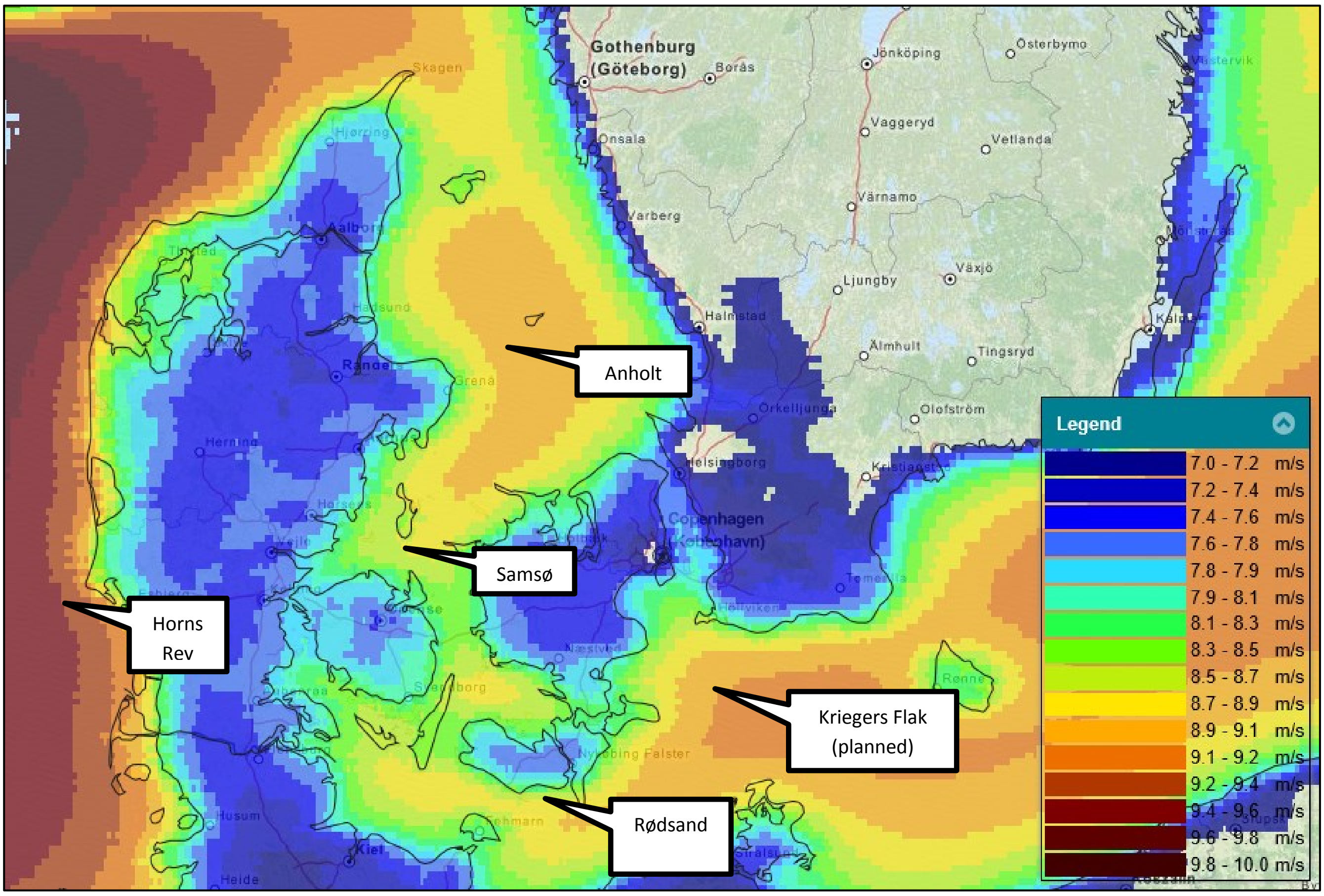


Figure 1 Wind resource map for Denmark (height above terrain/sea level: 75 m) based on EMD-ConWx meso scale modelled wind data [1]

The wind resource map of Denmark shows hub-height annual average wind speeds of 9-10 m/s in the Horns rev area, around 9 m/s in areas around Anholt and Kriegers Flak and 8-9 m/s in the Rødsand and Samsø areas. Due to the low surface roughness, the variation in wind speed with height is small for offshore locations; the increase in wind speed from 50m to 100m height is around 8%, for comparison the increase in wind speed from 50m to 100m height is around 20% for typical inland locations.

Input

Input is wind.

Minimum wind speed: 3-5 m/s.

Rated power generation reached around 12 m/s wind speed.

Cut-out or transition to reduced power operation at wind speed: 25- 30 m/s.

Most turbine manufacturers apply a soft cut-out for high wind speeds (indicated with dashed red curve in figure 2) resulting in a final cut-out wind speed around 30 m/s [2, 3].

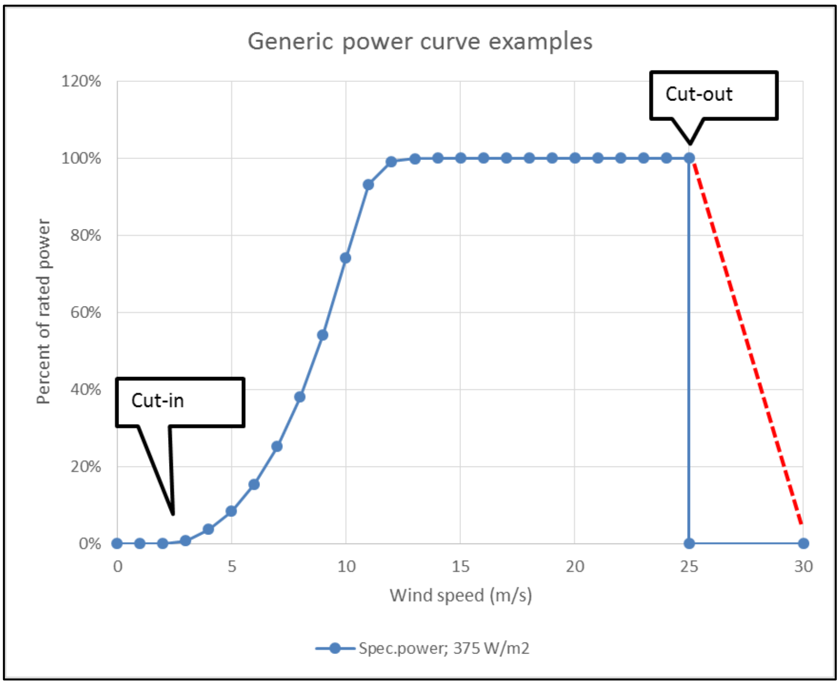


Figure 2 Power curve example [4]. Specific power values refer to e.g. 7 MW with 154 m rotor diameter.

Output

The output is electricity.

Modern offshore turbines located in Denmark have capacity factors of the order of 50%, corresponding to 4400 full load hours. A typical duration curve for a wind farm in the North Sea is presented in figure 3 below.

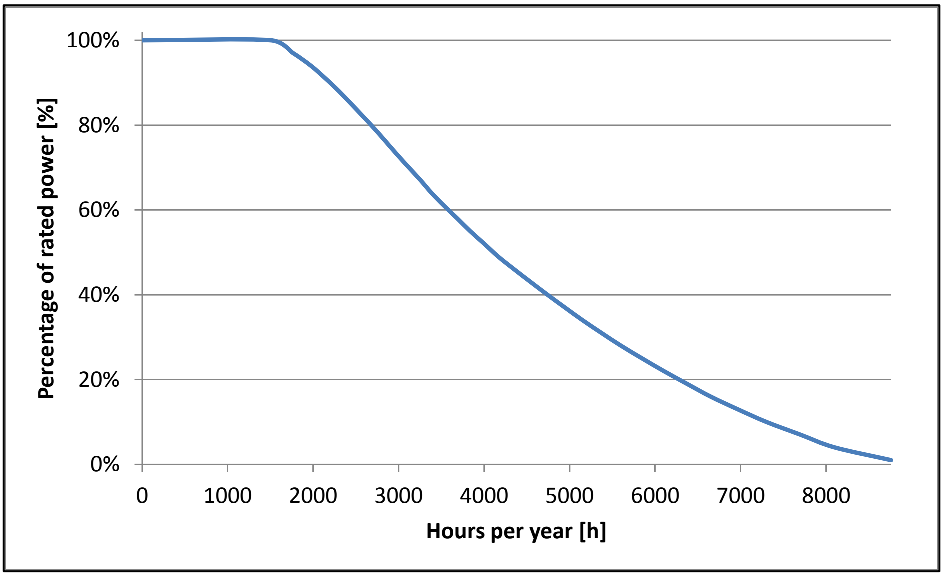


Figure 3 Example of a duration curve for a North Sea offshore wind farm [5]

Typical capacities

In 2015 the average capacity of offshore turbines under construction in Europe was 4.2 MW, ranging from 3 - 6 MW [6]. Turbine capacities of offshore wind turbines are expected to increase in the near term, with the introduction of new turbines with rated powers in the range of 6 - 8 MW. In Denmark a large jump in turbine capacity happens between the newest offshore wind farm Anholt and the next planned Horns Rev 3, with rated power increasing from 3.6 MW to 8 MW. Rotor diameters are expected to increase as well, maintaining a specific power of 300-400 W/m^2 [7]. However, specific power is expected to increase slightly in the near term in Denmark because of the large increase in capacity as seen for MHI Vestas' V164-8.0 MW and Siemens Wind Powers' SWT-6.0-154 and SWT-7.0-154. From 2020 and onwards 10+ MW turbines are expected to become commercially available, but it is not expected that such large turbines will be standard in Denmark before after 2030.

Towards 2020, the size of offshore wind farms in Europe (excl. Denmark) is expected to be in a range of 300 - 1200 MW. For some new projects the conditions will become more demanding than now: deeper waters (40-50 m) as well as larger distances to shore (100+ km).

In Denmark, the current planning comprises two offshore wind farms (Kriegers Flak (600 MW) and Horns Rev 3 (400 MW)) and six nearshore projects (350 MW in total, maximum 200 MW per site).

The size of offshore wind farm erected in Denmark in medium term is expected to be from 200 - 600 MW.

Wind resource and capacity factors

One of the major drivers for developing wind farms offshore rather than onshore is the better wind resource, which can justify some of the additional investment and O&M costs. Offshore wind farms installed in Denmark since 2009 have a weighted average capacity factor of 48%. For comparison, onshore wind turbines installed in Denmark since 2010 have an average capacity factor of 33%.

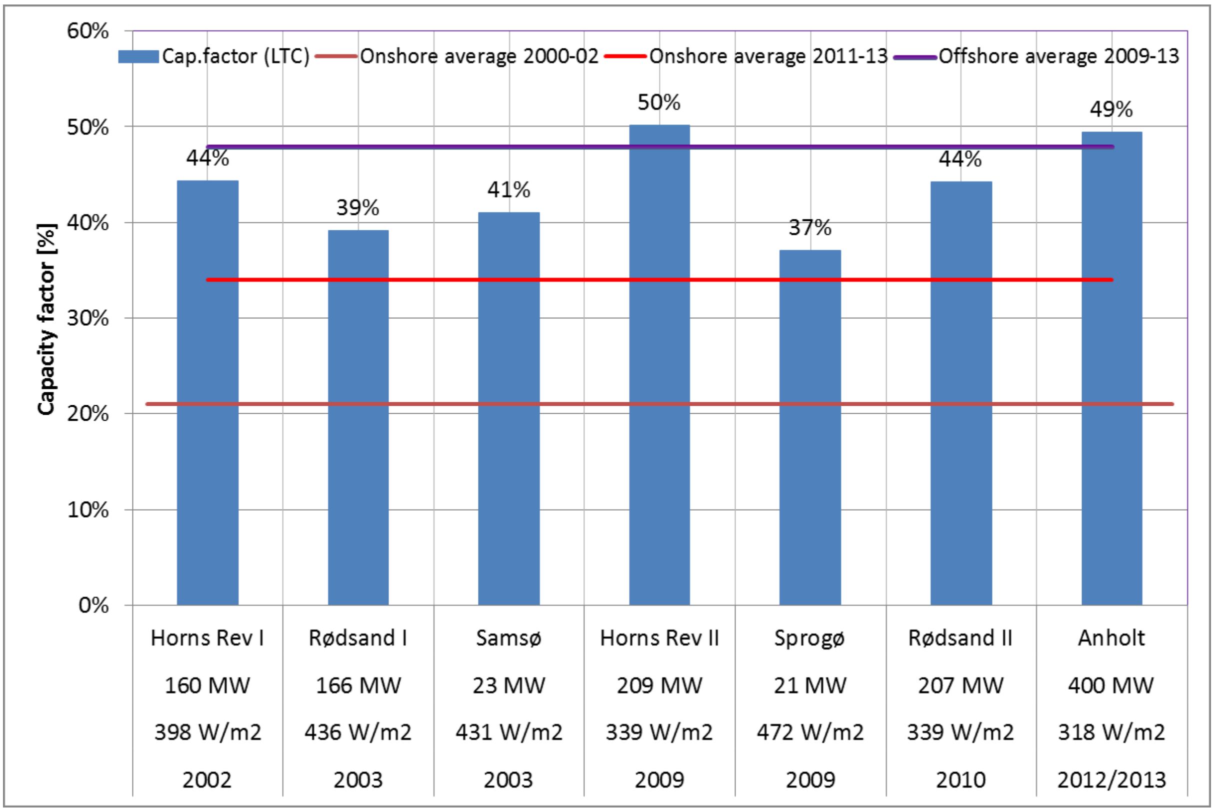


Figure 4: Long term corrected (LTC) capacity factors for five large offshore wind farms (>150 MW) and two smaller offshore wind farms located nearshore in Denmark. For comparison is shown the average capacity factor for onshore turbines installed 2000-02 and 2011-13 based on measured 2014 performance (which was a normal wind year) [8]. Year of commission shown in graph.

There is a significant variation in capacity factors between the different projects (figure 4). This is caused by a combination of differences in the turbine technologies, including different specific power values, and in the wind resources.

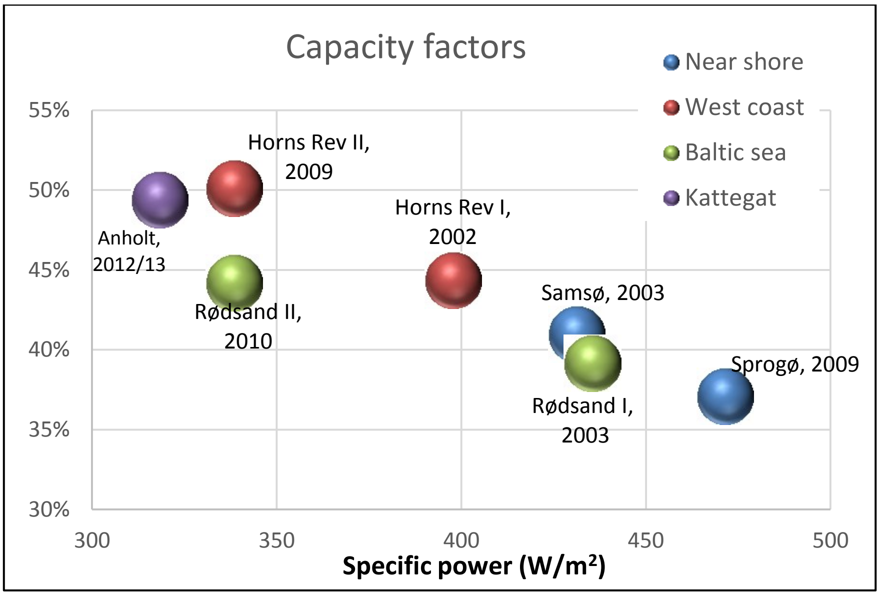


Figure 5: Capacity Factor shown as function of the Specific Power (W/m^2) for Danish Offshore wind turbine projects. The 3 most left are the latest projects.

Figure 5 shows the capacity factor as a function of the specific power, with locations represented by the coloring. Both the location and the specific power are key drivers of the capacity factor. Horns Rev I and Horns Rev II have similar wind resource, but different specific power and therefore different capacity factors. Likewise Rødsand I and Rødsand II have similar wind resource, but different specific power and therefore different capacity factors.

Regulation abilities and power system services

Offshore wind turbines have similar regulation and ancillary service capabilities to onshore turbines. See the descriptions in the chapter about onshore wind turbine.

Offshore wind turbines have a disadvantage for regulation of voltage and reactive power in the main power grid, because of the large distances between the wind farm and the point of connection to the power grid. A larger distance will result in an increased impedance and loss. An offshore wind farm will be able to compensate for reactive power created by itself, however their contribution to further compensation of reactive power in the main grid is limited depending on the distance to point of connection. Onshore wind turbines, which in general are closer to the grid, have better possibilities for contributing to regulation of voltage and reactive power.

Advantages/disadvantages

Offshore wind turbines have similar general advantages and disadvantages to onshore turbines. See the chapter “Wind turbines onshore”.

The major advantages of offshore wind turbines, relative to onshore wind turbines, are the better wind resources offshore, the reduction of the visual and noise impacts from turbines which has become a major barrier for onshore deployment, and the possibility of building much larger wind farms than onshore.

There are, however, major logistical challenges associated with building wind turbines offshore. These challenges have resulted in high capital costs for developing offshore wind farms.

Electricity from offshore wind production may become an export product in the future, as Denmark has relatively more space for offshore development than most European countries.

Environment

Some disturbance to sea-life must be anticipated during the construction phase for offshore wind turbines.

Before, during and after the construction of two Danish wind farms Horns Rev I and Rødsand I, comprehensive monitoring programmes were launched to investigate and document the environmental impact of these two wind farms [9]. The monitoring programmes showed that, under the right conditions, large wind farms pose low risks to birds, mammals and fish. Species diversity even tends to increase due to the increase in habitat heterogeneity resulting from the foundations, which act as miniature reefs.

Consequently, the results from the monitoring programmes demonstrated that it is possible to establish offshore wind farms in a way, which is environmentally sustainable and which causes negligible damage to the marine environment.

Research and development perspectives

Besides the R&D potential described in the chapter "Wind turbines onshore‟, offshore technology development is expected to include [10, 11].

- Further upscaling of wind turbines
- New foundation types suitable for genuine industrialization
- Development of 66kV electrical wind farm systems as alternative to present 33 kV.
- Development of compact offshore substations, including high-voltage direct current (HVDC) converter stations and cables. HVDC equipment is available today.
- Improvement of design methods in planning and operation phase, e.g. reduction of wake losses, O&M costs by e.g. improved control strategies, more optimized tower/foundation structure by integrated design.
- Logistic issues, e.g. more dedicated vessels in installation and maintenance phase.
- Improved methods for handling of different sea bed conditions, lowering foundation costs.
- Improved monitoring in operational phase for lowering availability losses and securing optimal operation.

At the present time the pace of product development and competition is high. Consequently, projects are often planned and developed on the basis of turbines that are not yet in serial production.

Examples of best available technology

The latest major offshore wind farm installed in Denmark is the Anholt offshore wind farm. It consists of 111 Siemens Wind Power turbines (SWT-3.6-120), each with 3.6 MW capacity, resulting in a total installed capacity of 400 MW. The wind turbine has 120 m rotor diameter, leading to a specific power of 318 W/m^2. The SWT-3.6-120 has by far been the most common offshore wind turbine the last few years, however larger turbines are currently entering the market as for instance Siemens Wind Powers' SWT-7.0-154 and MHI Vestas' V164-8.0 MW [6].

Currently Siemens Wind Power offers 3.6 MW and 4 MW geared turbines and 6 MW and 7 MW direct drive turbines. MHI Vestas offers an 8.0 MW geared turbine, and Senvion, Areva/Gamesa (Adwen) and Alstom are all offering turbines in the 6-8 MW range [10]. The 8.0 MW MHI Vestas turbines have been selected for the Horns Rev III project, which is expected to be commissioned in 2018-19.

Prediction of performance and cost

Breakdown of costs

A breakdown of costs of a typical offshore wind farm reveals that the wind turbine represents a smaller portion of the total investment, when compared to onshore projects. This portion gets even smaller, when the project is far from shore and in deep waters. In Denmark, where wind farms are typically awarded by a tender process, the cost of substation, export cable and the environmental impact assessment are not financed by the project developer for offshore projects, but financed by the electricity consumers. The array cables connecting the turbines with the substation are however covered by the developer. Furthermore, offshore wind farms built under the open-door [6] application scheme must carry the costs of grid connection from the wind turbine to point of connection to national grid (e.g. array cable, substation and export cable) and environmental impact assessments. These costs are included in figure 6 in order to provide a more accurate picture of the total costs associated with developing offshore wind farms in Denmark.

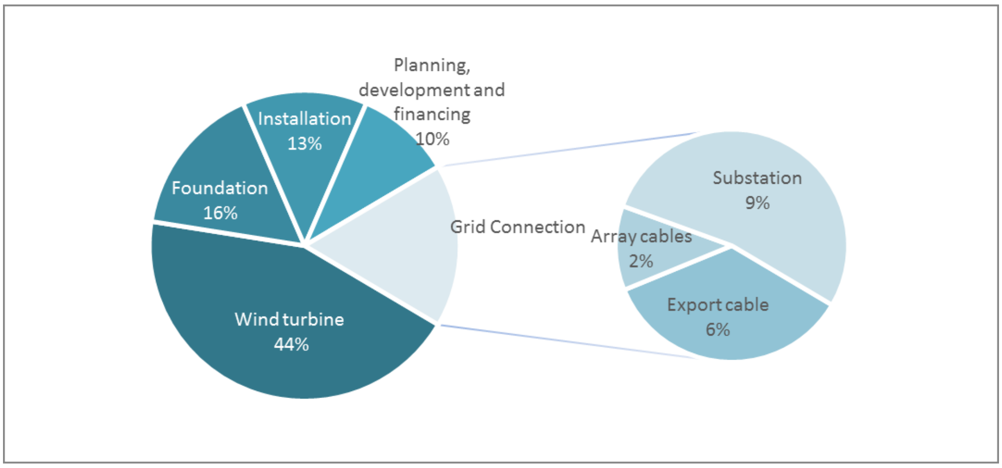


Figure 6: Breakdown of costs for offshore wind farms (Renewable Energy Technologies: Cost Analysis Series, 2012). The cost of environmental assessment is a part of the Planning & development and financing cost component

[6] In the open-door procedure, the project developer takes the initiative to establish an offshore wind farm of a chosen size in a specific area. This is done by submitting an unsolicited application for a license to carry out preliminary investigations in the given area.

Cost dependence of water depth, distance to shore and wind farm size

Table 1 shows the costs of foundations (material + installation) for different water depths. The costs are estimated by two different studies, dated 2007 and 2014, respectively [12, 13]. It should be noted that the Study 2 is Siemens price-forecast and not realized results.

Water depth	Foundation cost (M€/MW)	
(m)	Study 1	Study 2
10	0.48	
20	0.74	0.42
30	1.18	0.67
40	1.88	0.84
50	---	1.05

Table 1: Foundation costs (monopile foundations, 2015 prices, 50m is a jacket construction) at different water depths, study 1 (from 2007) [14], Study 2 (from 2014) [13] based on recent price-forecast from Siemens Wind Power.

Figure 7, figure 8 and figure 9 show the total investments cost for offshore wind farms (including grid connection costs) as a function of water depth, distance to shore, and farm size, respectively. The figures are based on 35 projects commissioned from 2002 to 2014 [15, 16].

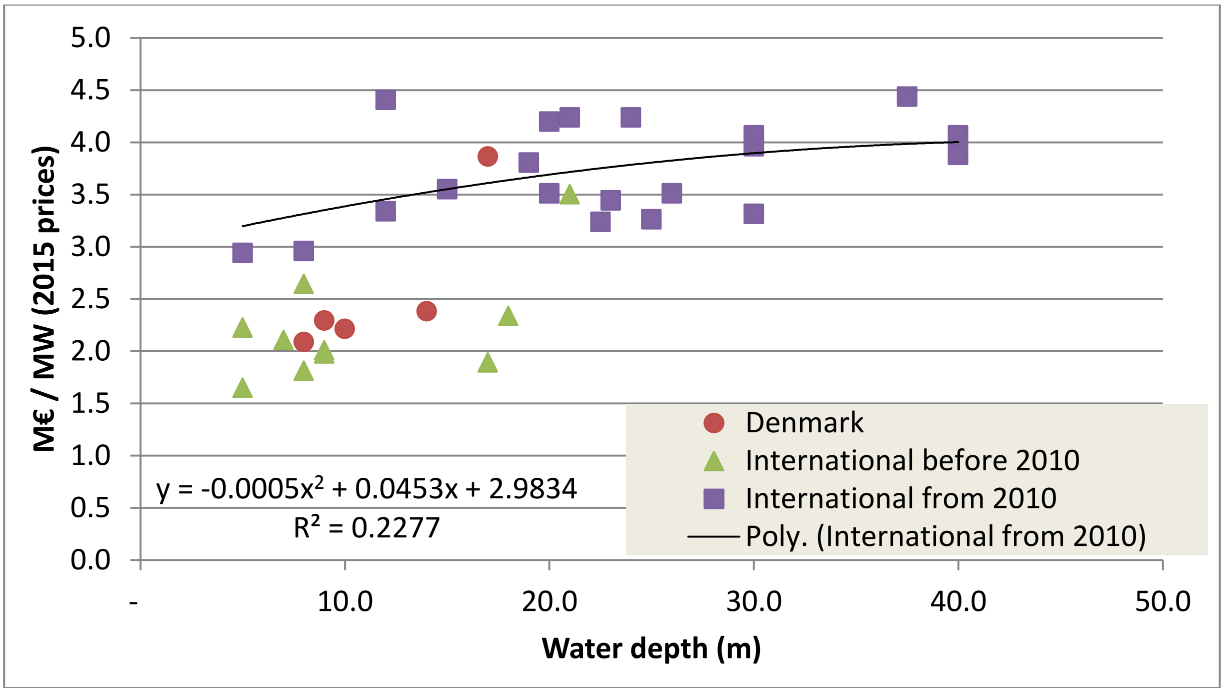


Figure 7: Cost plotted against water depth for 35 realized offshore projects in DK, UK, DE and SE from 2002 to 2014.

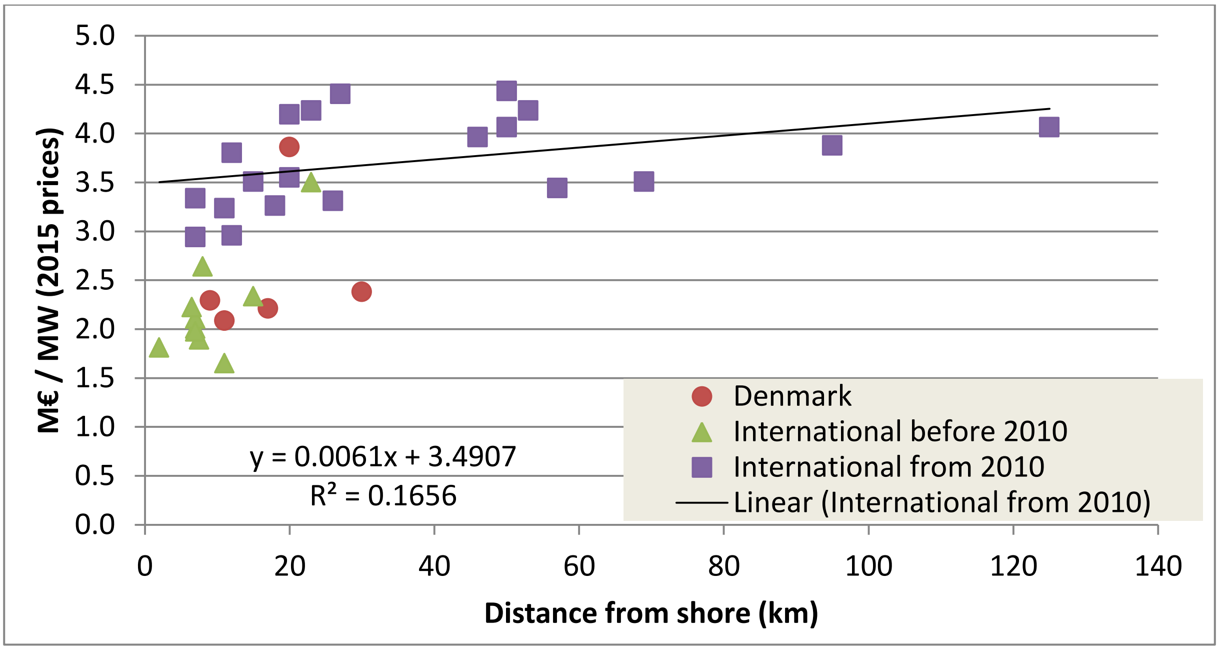


Figure 8: Cost plotted against distance to shore for 35 realized offshore projects in DK, UK, DE and SE from 2002 to 2014.

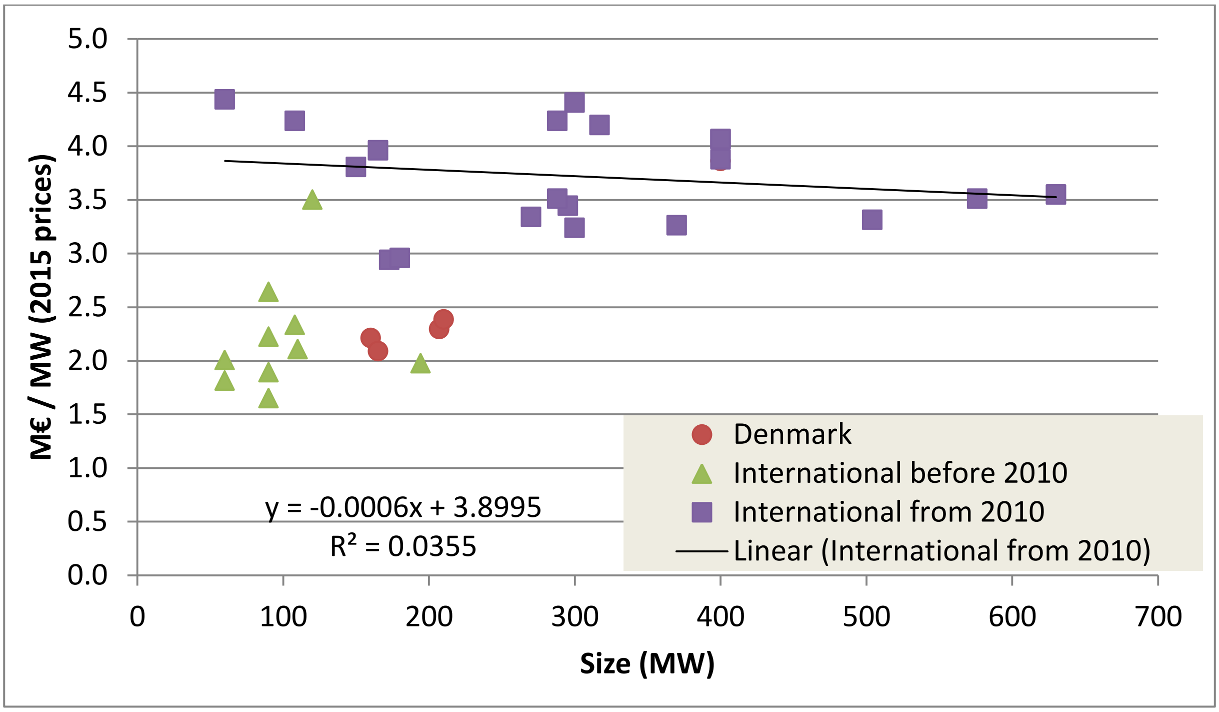


Figure 9: Cost plotted against farm size for 35 realized offshore projects in DK, UK, DE and SE from 2002 to 2014.

The trend lines for international projects commissioned from 2010 to 2014 represent the overall cost sensitivities to water depth, distance to shore, and wind farm size. It should be noted, however, that the statistical significance of the trend lines are relatively poor due to the multi-variable cost drivers and project-to-project variations.

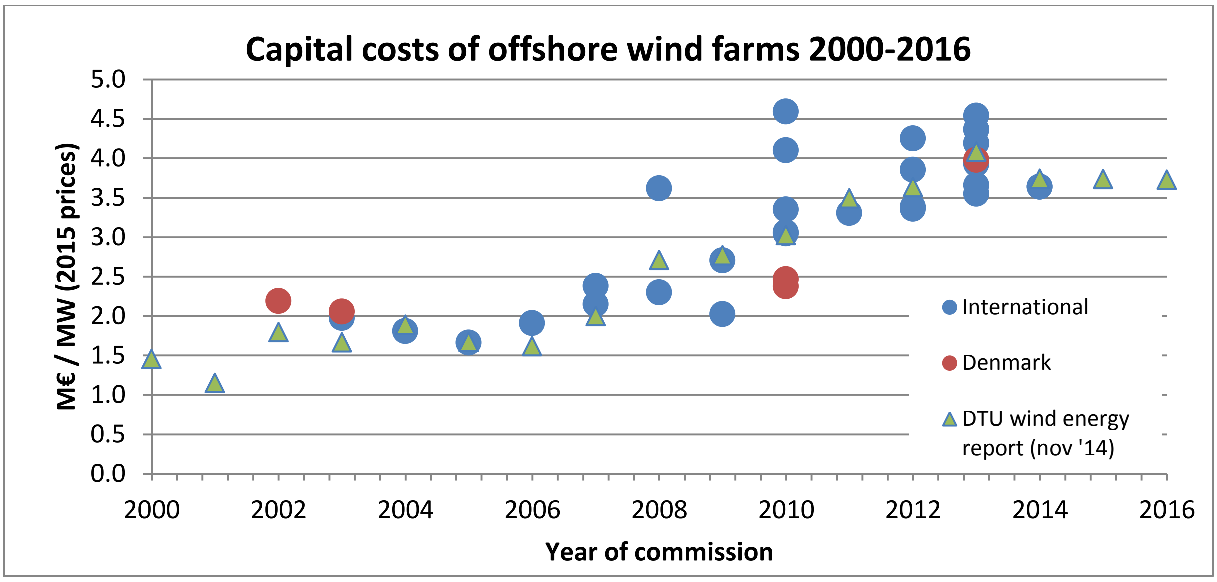


Figure 10: Capital costs for offshore wind farms. EMD graph based on data from [10, 15, 16]. The dot is placed at the first year in operation. Cost includes substation and land cable [10] and is annual averages based on selected projects and includes prognoses for 2015-16. The latest Danish project Horns rev III is not included in the graph.

In addition to the general sensitivities of cost to water depth, distance to shore, and wind farm size, figure 10 show a step-change in cost from the early projects (before 2010) to projects commissioned the recent years (since 2010). It is generally believed that the reason for this step-change is the result of a combination of factors. Firstly, during the second half of the first decade the offshore wind industry underwent a transformation from "pioneer" to "professional". As a result, calculation practices from other large project businesses were implemented to a larger degree, resulting in systematic application of risk adders, often leading to stacking of risk adders to a significant degree. Secondly, at the same time the market changed from a buyer's market to a seller's market, with the traditional and inherent consequences of such change. Finally, the industry moved towards lower specific power (larger rotors pr. MW), which unavoidably leads to an increase in cost per MW.

Prediction of capacity factors and lifetime

Capacity factor as well as turbine dimension is very dependent on the wind site. The average wind speed is larger in the Northern Sea than in the smaller waters east of Jutland. Therefore wind turbines with lower specific power are expected to be chosen for the low wind sites as compared to the Northern Sea in order to exploit the wind resource better at low to medium wind speeds. In the Northern Sea turbines with larger specific power are expected to be chosen since they are expected to be cheaper and more robust to extreme weather conditions. This difference in turbine dimensioning will to some extent level out the capacity factor between the Northern Sea wind sites and the inland water wind sites. In the data sheet an expected weighted average of specific power and capacity factor is aimed for.

The capacity factor is high in Denmark and is expected to increase more than in comparable countries. Especially German offshore wind farms are expected to experience wake effects because they will be located densely due to heavy deployment and scarcity of wind sites, whereas Danish sites are more abundant in the Northern Sea compared to the size of the country [17].

The offshore wind farm capacity factors are expected to increase, mainly due to larger hub heights with associated higher average wind speeds and lower specific power. Wind sites are expected to be of the same average quality as the existing offshore wind sites with respect to wind speed, water depth, distance to nearest harbor etc. until after 2030. There after sites in the North Sea further from shore are expected to be utilized which are more expensive but also have higher average wind speeds. Finally, technological improvements such as step up to 66 kV connections to substations are expected to contribute to increased capacity factor. It is predicted that the overall increase in capacity factor will be higher for offshore than for nearshore.

Nearshore wind turbines are hard to estimate in the far future because the amount of feasible sites in Denmark is limited and therefore they are expected to be fully deployed before 2050. Alternatively, nearshore wind farms will be located further from the shore and will be located at sites currently expected to be offshore sites.

In the projections we assume that future nearshore wind sites will be of the same kind as the nearshore sites tendered in 2016 in terms of distance to shore, size, wind speed and water depth. Therefore, there will be only few sites. These sites are expected to be cheaper but also to have lower wind speeds than offshore sites.

The project lifetime is expected to increase from 25 years in 2015 to 30 years in 2030 due to more mature technologies and a dedicated focus on extended life.

Prediction of cost in 2015 and 2020

In 2015 and 2016, five tenders have been settled for offshore wind farms in Denmark and in the Netherlands, where conditions are considered to be comparable. Data from these five projects has contributed to determine investment costs (CAPEX) and costs of operation and maintenance (OPEX) for the period 2015 to 2020. An overview of wind farms which have been put out to tender in 2015 and 2016 is shown in Table 2.

Project	Country	Farm size [MW]	Year(FID)	Winning
Horns Rev 3 (HR3)	DK	406,7	2015	Vattenfall
Kriegers Flak (KF)	DK	600	2018	Vattenfall
Borssele 1+2 (BS1+2)	NL	Approx. 700	2017	DONG
Borssele 3+4 (BS3+4)	NL	Approx. 700	2020	Shell
Near shore (Vesterhav North and South)	DK	350	2017/2018	Vattenfall

Table 2: Overwiew of the winning bids for offshore wind farm in 2015 og 2016 in Denmark and the Netherlands.

CAPEX

Vattenfall has announced that they expect to invest around 1 billion € in HR3 , which corresponds to approx. 2.46 million € per MW (2015 prices). Furthermore Vattenfall has announced that they expect to invest around 1.1 - 1.3 million € in KF(2016 prices) corresponding to 1.97 €/MW (2015 prices). No project costs have been published for the remaining offshore farms in Table 2.

Looking at Vattenfall's announcements, CAPEX per. MW has decreased just 15-25% from HR3(primo 2015) to KF (end 2016), while the bid price per kWh decreased about 50%. Hence, other parameters affecting the bid price for KF must have decreased more than the investment costs. Some explanations could be, for example, lower financial costs and increased competition, scale effect (KF is larger than HR3, advantages of many projects in a short period [IRENA, October 2016], and of projects located nearby, i.e. reduction of costs for ships and other facilities.

Near shore wind farms; Vesterhav north and Vesterhav south, are included in the analysis. However, it is assumed that the ocean depth is the same as for offshore wind turbines (15-25 m), and the two farms can be seen as one 350MW project, as Vattenfall has won both bids and that there will be a synergy with HR3. Hence, the costs of the Vesterhav (north) and Vesterhav (South) are assumed lower than for average near shore wind farm.

OPEX

No OPEX has been announced for the winning bids in 2015 and 2016 (HR3, KF, near shore and Borssele 1-4). Therefore, OPEX (FID 2015) has been determined based on the announced average OPEX for existing offshore wind mills owned by DONG (in 2016), indications from interviews with the industry and analysis of bid prices. The average OPEX for DONG Energy's existing parks is approx. 0.086 million € per. MW per year. Hereafter OPEX for 2015 (FID) has been assumed approx. 10% lower than the average for existing parks.

OPEX and CAPEX

In addition to the above considerations, an assessment of OPEX and CAPEX has been done by calculating internal interest rates and then evaluating the calculated internal return based on the expectation that a significantly lower rate of return is accepted at the end of 2016 than at the beginning of 2015. The calculation includes several other parameters that are subject to considerable uncertainty, for example projection of electricity prices and expected annual electricity production. The entire method is thus subject to great uncertainty, but is considered to be the best approach, taken into account the available information. Table 2 shows data for the mentioned projects.

	Horns rev 3	Near shore	Borssele 1+2	Krigers flak	Borssele 3+4
Internal interest rate relative to the period 2015-2016	High	Middle	Middle	Low	Low
Farm size (MW)	406,7	350	700	600	700
Expected windmill size (MW) [7]	8,3	8-10	6-10	8-10	8
Distance from coast (km)	30	4-7	31	15-25,5	15-37
Sea depth (m)	11-19	10-25	14-38	15-30	40
Feed in tariff (DKK / MWh)	770	468	534	366	400
Estimated grant period (year)	11.2	11.1	15.0	11.2	14.7
Commission Year	2020	2020	2020	2021	2023
Production in the commission year [8]	25%	25%	25%	10%	50%
FID year(assumed)	2015	2017	2017	2018	2020
Expected electricity price projection[9]	EUBF14 minus10 %		EUBF14	EUBF14 minus 10 %	EUBF14
Time for publication of winning bid	Feb. 2015	Sept. 2016	July 2016	Nov. 2016	Dec. 2016
Winner of the project	Vattenfall		DONG	Vattenfall	Shell
CAPEX (M€/MW) +/- 0,5	2.46	2.07	2.09	1.81-2.13	1.92
OPEX(M€/MW/år) +/- 0,02	0.077	0.064	0.071	0.062	0.059

Note 1: Data with red print are own assessments.

Note 2: OPEX is stated as a total costs, which covers an assumption of 75% fixed costs and 25% that vary with production.

Note 3: In the assessment, it has been assumed that costs of nearshore wind farms are approx. 10% lower than for offshore wind farms. Moreover, it has been taken into account that the costs for near shore wind farm, as reflected in the bids, include payment for grid connection. CAPEX for near shore wind mills, however, is excl. grid connection.

Table 3: Data for Danish and Dutch projects for which tenders were submitted in 2015 and 2016 (2015 prices).

Prediction of Grid connection costs for the period 2015 to 2050

The assessment of costs of grid connection is based on information from Energinet about the costs of connecting the latest four projects (HR2, Rødsand 2, Anholt and HR3) with emphasis on on the latest projects. Based on this, it is estimated that grid connection costs are approx. 0.4 M € / MW for offshore wind farms with transformer station located on offshore platform, farm size 400-600MW and located about 30 km from the coast. Moreover, it is assumed that the grid connection costs are approx. 0.3 M € / MW for near shore wind farms that are connected to onshore transformer stations, farm size 50-200 MW, and located 4-10 km from the coast. Distribution of costs is shown in Table 5.

[7] http://www.4coffshore.com/windfarms/vesterhav-nord-denmark-dk55.html

[8] Production in the first year in percentage of full production, - not all the turbines are in service January 1 in the first year of production.

[9] "EUBF14" is an electricity price projection used by the Danish Energy Agency, at the time of the tender. After 2024, the average spot market price for electricity is expected to be 28.5€/MWh. For "EUBF minus 10%" the electricity price is 10% lower. EUBF minus 10% is assumed for Danish offshore wind farms because the wind-weighted electricity price in Denmark is expected to be lower than average. "EUBF14" is used for Dutch parks because there is an expectation of a slightly higher electricity price in the Netherlands.

Grid connection costs (FID 2015, 2015 prices)		Off shore wind mills	Near shore wind mills
Total costs [10]	**mio. €/MW**	0.40	0.28
Offshore platform	**mio. €/MW**	0.16	0.00
Project management and environmental assessment	**mio. €/MW**	0.027	0.040
Transformer station onshore	**mio. €/MW**	0.067	0.10
Sea cable total costs	**mio. €/MW**	0.081	0.040
Land cable total costs	**mio. €/MW**	0.067	0.10
Sea cable costs per km	DKK/km/MW	2,685	4,027
Land cable costs per km	DKK/km/MW	1,342	2,013
Sea cable length	Km	30	10
Land cable length	Km	50	50

Table 4: Network connection costs for offshore wind farms of 400-600MW and near shore wind farms of 50-200MW

Prediction of costs of grid connection in the future has been calculated by assuming that the costs drop by 1% per year until 2020, by 0.75% per year between 2020 and 2030 and by 0.5% per year after 2030. The learning rate method is not used because some parts of the grid connection technology are considered mature while other parts are not, consequently different parts will be at different stages on the learning curve and consequently it is also difficult to assess the accumulation of "capacity put into operation".

Prediction of cost for the period from 2010 to 2050

The overall quality of offshore wind sites is expected to be at the same level as the current offshore wind sites with respect to distance to shore, water depth, wind speed etc. After 2030 the best wind sites are expected already to be utilized and slightly worse wind sites will be used resulting in an increased cost per kWh relative to an average pre 2030 wind site [14]. The main drivers for this increase in cost will be distance to shore and water depth since the post 2030 wind sites are expected to be located in the Northern Sea.

As mentioned above the project costs of offshore wind farms commissioned in the first years of the century were substantially lower than the costs of projects commissioned during recent years. Project costs appear to be levelling off now after having steadily increased over the last decade [10].

Significant cost reductions are expected in the future as a consequence of research and development efforts in relation to all main factors affecting the total cost of energy – turbine performance vs cost, foundation costs, electrical infrastructure costs and O&M.

Furthermore, ambitious deployment plans for offshore wind power in Denmark and the rest of Europe in the coming years are expected to reduce the capital cost, the O&M costs and the construction time of offshore wind farms through increased industrialization and economics of scale.

MegaVind has set a target of a 50% reduction in LCOE for offshore wind from 2010 to 2020 [18].

[10] Energinet.dk marts 2017

In 2011 The British Department of Energy and Climate Change (DECC) set the goal to reduce LCOE of offshore wind power by 30% by 2020 for off shore wind under British conditions. Furthermore, the studies estimate that the cost reduction is on track or ahead of the goal [19].

The Dutch government has set a goal to reduce LCOE of offshore wind by 40% from 2010 to 2020 FID. A reduction potential of 46 % is found assuming that the potential covers technology as well as supply chain and financial cost reduction [20].

A study from Germany assesses two scenarios of offshore wind power penetration in Europe, three site characteristics and the corresponding cost reductions from 2013 to 2023. 17-27% cost reductions are estimated in capital cost in the period leading to a capital cost of 3,057-3,440 M€/MW in 2023. O&M costs are expected to reduce 19-33% by 2023. On the wind site most similar to Danish wind sites, reduction in LCOE of 29-36% are expected in the period achieving [17].

The above mentioned sources are the basis of the projections in the data sheet along with information about the existing offshore wind farms. The theory of learning rates is used to project price reductions from 2020 to 2030 [21].

Only few of the sources described above provide a full set of data including detailed cost reduction in investment and O&M, interest rate, projected deployment, etc. Furthermore, most of them do not look any further than year 2020. Therefore the estimates in these sources are only used as indications of a level of cost reduction.

After 2030, the learning rate approach with origin in European deployment is not assumed to be valid because the technological development is expected to be more affected by the global market development. Therefore a cost reduction is estimated rather than a learning rate from 2030 to 2050.

Based on these sources, the learning rates are assumed to be around 10% for both investment and O&M cost for offshore and slightly lower for nearshore because some of the expected cost reductions are related to offshore substations, deep waters and long distance to shore. Furthermore the same cost reduction is assumed for investment and O&M in the period (2030-2050) as in the period (2020-2030) for both offshore and nearshore.

These projections result in a learning rate for reduction in cost of electricity production which is a central estimate compared to the above mentioned reduction goals and cost projections. The absolute costs of offshore wind power electricity production are significantly lower in Denmark than in comparable countries today and in the projections due to the framework conditions and excellent Danish offshore wind sites.

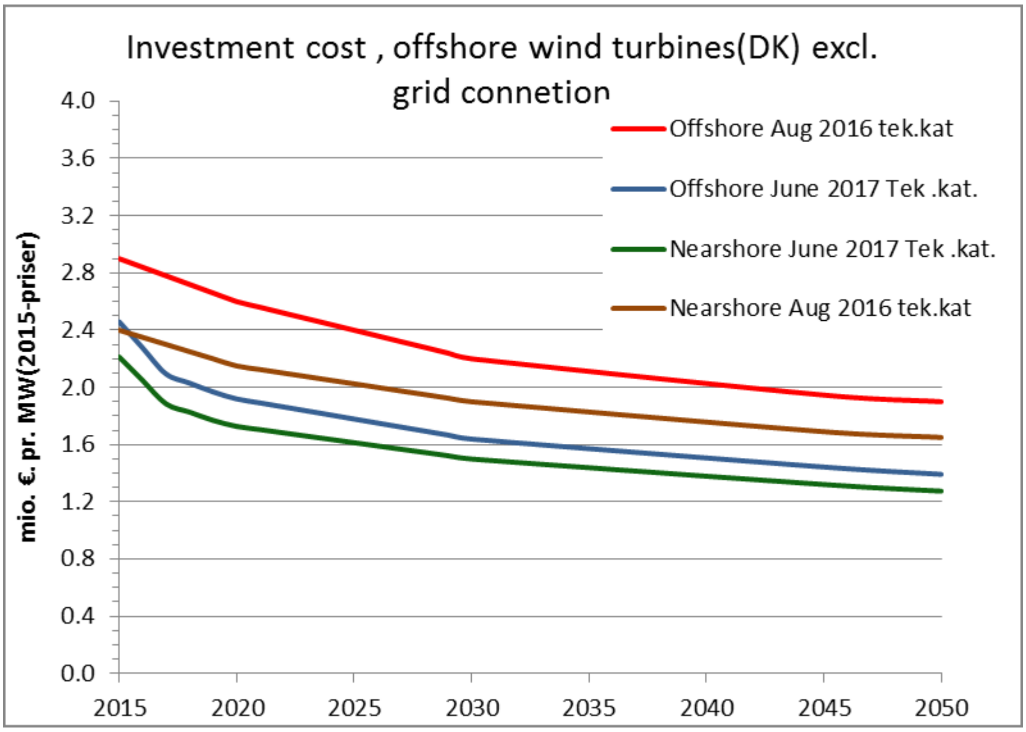


Figure 11: Expected development in investment cost (excl. grid connection) wind farms in Denmark

Uncertainty

There are several uncertainties, not just in cost and improvement of performance of the technology, but also on supply chain and service opportunities. The cost reductions related to supply chain and service is dependent on the international level of deployment of wind power as well as the national availability of service which is dependent on the continuity and level of national deployment of offshore wind power.

Future demands offshore

In the future it could be expected that the offshore wind turbines will be met with

- More focus on wildlife issues due to larger and more numerous projects
- More demands on participation in grid regulation and grid expansion in general

Data sheets

Technology	Large wind turbines, Off-shore									
Year of final investment decision	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	8	10	12	15	4.0	10.0	4.0	20.0	A1	6, 13, 10
Average annual full-load hours	4400	4500	4650	4900	4000	5000	4000	5500	A	8, 10, 27
Forced outage (%)	4.0%	3.0%	3.0%	2.0%	1.0%	5.0%	1.0%	5.0%	B	27
Planned outage (%)	0.3%	0.3%	0.3%	0.3%	0.1%	0.5%	0.1%	0.5%	C	
Technical lifetime (years)	25	27	30	30	20	35	20	35	D	
Construction time (years)	3	2.5	2.5	2	1.5	4	1.5	4	E	27
Space requirement (1000m2/MW)	185	185	185	185	168	204	168	204	F	14
Regulation ability										
Primary regulation (% per 30 sec.)									G	
Secondary regulation (% per min.)									G	
Financial data										
Nominal investment (M€/MW) excl. grid connection	2.46	1.92	1.64	1.39	1.73	2.02	1.11	1.53	H,J,K	10, 15, 16, 30, 31,33.34
Nominal investment (M€/MW) grid connection	0.40	0.38	0.35	0.32	0.35	0.41	0.27	0.37	L	31,35
- of which equipment	45%	45%	45%	45%	40%	50%	40%	50%		26, 12, 27
- of which installation	55%	55%	55%	55%	50%	60%	50%	60%		26, 12, 27
Fixed O&M (€/MW/year)	57,300	44,300	37,800	32,100	39,900	46,500	25,700	35,300	I, J	31, 32, 34
Variable O&M (€/MWh)	4.3	3.3	2.7	2.2	3.0	3.4	1.7	2.4	I, J	26, 12, 27, 31,32,34
Technology specific data										
Rotor diameter	164	190	210	240	---	---	---	---		14, 10
Hub height	103	115	125	140	---	---	---	---		14, 10
Specific power (W/m2)	379	353	346	332						
Average capacity factor (%)	50	51	53	56	46	57	46	63		8, 27
Average availability (%)	96%	97%	97%	98%	99%	95%	99%	95%		27
Specific area coverage (MW/km2)	5.4	5.4	5.4	5.4	4.9	5.9	4.9	5.9		14, 10

Notes:

A1 The capacity in 2015 is set to 8 MW since the only offshore windfarm decided in 2015 was Horns Rev 3 with turbines of 8.3 MW.

A The full load hours (annual production (MWh) per installed power (MW)) depending on the actual location of the wind farm, wake losses and technological characteristics of the individual turbine. The value is an average for location where it is expected the turbines will be placed. Specific area coverage 5.4 MW/km^2 is assumed, further more it is assumed that offshore turbines are in farms with a total capacity of app. 400-600 MW.

B Offshore turbines has typically higher forced outage than onshore due to access problems in harsh weather

C Planned outage is typically 1-2 service visits a year, with a 1-2 work days

D The life time depends on the wind conditions; average annual speed and turbulence, relative to the design class of the turbine

E The construction time is the period from FID to commissioning. The construction time depend on the size of the project, vessel available and weather conditions.

F Based on 5,4 MW/km^2 - can vary some and will often be a political decision - a given area is available and a number of MW tendered. The wake losses will highly depend on the space available per MW.

G Wind turbines can be downward regulated within very short time and can therefore (if the wind is blowing) be used in both the primary and secondary downward regulation.

H The cost includes cost of wind turbines, foundation, installation, planning & development and financing and internal grid connection (array cable, substation but not export cable).

I 75 % of the total yearly O&M costs are assumed to be fixed cost and 25 % are assumed to be variable cost.

J From 2020-2030 10% learning rate is assumed, from 2030-2050 15% reduction is assumed

K Deducted from , five tenders have been settled for offshore wind farms in Denmark and in the Netherlands, described in details in the note [31]

L Assuming that the costs drop by 1% per year between 2015 and 2020, by 0.75% per year between 2020 and 2030 and by 0.5% per year after 2030

Technology	Large wind turbines, Near-shore									
Year of final investment decision	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	8	10	12	15	4.0	10.0	4.0	20.0	A1	6, 13, 10
Average annual full-load hours	4400	4500	4650	4900	4000	5000	4000	5500	A	8, 10, 27
Forced outage (%)	3.5%	3.0%	2.5%	2.0%	1.0%	5.0%	1.0%	5.0%	B	27
Planned outage (%)	0.3%	0.3%	0.3%	0.3%	0.1%	0.5%	0.1%	0.5%	C	
Technical lifetime (years)	25	27	30	30	20	35	20	35	D	
Construction time (years)	2	2	2	2	1	3	1	3	E	27
Space requirement (1000m2/MW)	185	185	185	185	168	204	168	204	F	14
Regulation ability										
Primary regulation (% per 30 seconds)									G	
Secondary regulation (% per minute)									G	
Financial data										
Nominal investment (M€/MW) excl. grid connection	2.21	1.73	1.50	1.28	1.56	1.82	1.00	1.38	H,K,J	10, 15, 16, 30, 31,33.34
Nominal investment (M€/MW) grid connection	0.28	0.27	0.25	0.22	0.24	0.29	0.18	0.27	L	31,35
- of which equipment	45%	45%	45%	45%	40%	50%	40%	50%		26, 12, 27
- of which installation	55%	55%	55%	55%	50%	60%	50%	60%		26, 12, 27
Fixed O&M (€/MW/year)	51,570	39,870	34,020	28,890	42,800	52,400	29,000	43,600	I, J, K	31, 32, 3
Variable O&M (€/MWh)	3.9	3.0	2.4	2.0	3.2	3.9	2.0	3.0	I, J, K	26, 12, 27, 31,32,34
Technology specific data										
Rotor diameter	164	190	210	240	---	---	---	---		14, 10
Hub height	103	115	125	140	---	---	---	---		14, 10
Specific power (W/m2)	379	353	346	332						
Average capacity factor	50%	51%	53%	56%	46%	57%	46%	63%		8, 27
Average availability (%)	96%	97%	97%	98%	99%	95%	99%	95%		27
Specific area coverage (MW/km2)	5.4	5.4	5.4	5.4	4.9	5.9	4.9	5.9	F	14, 10

Notes:

A1 The capacity is set to 8 MW, the turbines at Horns Rev 3 is expected to have a capacity of 8.3 MW, it is assumed that the same turbines will be used near shore and off shore

A The full load hours (annual production (MWh) per installed power (MW)) depending on the actual location of the wind farm, wake losses and technological characteristics of the individual turbine. The value is an average for location where it is expected the turbines will be placed. d a Specific area coverage 5,4 MW/km^2 is assumed, further more it is assumed that nearshore turbines are placed in farm with a total capacity of 50 -250 MW

B Offshore turbines has typically longer forced outage than onshore due to access problems in harsh weather

C Planned outage is typically 1-2 service visits a year, with a 1-2 work days

D The life time depends on the wind conditions; average annual speed and turbulence, relative to the design class of the turbine

E The construction time is the period from FID to commissioning. The construction time depend on the size of the project, vessel available and weather conditions.

F The wake losses will highly depend on the space available per MW, Specific area coverage of 5,4 MW/km^2 is assumed. In a tender typically a given area is available and and a given capacity MW is demanded.

G Wind turbines can be regulated downward within short time and can therefore (if the wind is blowing) be used in both the primary and secondary downward regulation.

H The cost includes cost of wind turbines, foundation, installation, planning & development and financing and internal grid connection(array cable)

I 75 % of the total yearly O&M costs are assumed to be fixed cost and 25 % are assumed to be variable cost.

J 9% learning rate is assumed for total investment cost and for O&M between 2020 and 2030

K Deducted from , five tenders have been settled for offshore wind farms in Denmark and in the Netherlands, described in details in the note [31] Assuming that Nearshore wind farms is 10% cheaper than offshore in 2015 and 2020.

L Assuming that the costs drop by 1% per year between 2015 and 2020, by 0.75% per year between 2020 and 2030 and by 0.5% per year after 2030

References

[1] E. I. a/s, http://www.windprospecting.com/, 2015.

[2] Enercon Product overview, 2012. [Online]. Available: http://www.enercon.de/p/downloads/ENERCON_PU_en.pdf.

[3] Siemens Wind Power, 2014. [Online]. Available: http://www.energy.siemens.com/br/pool/hq/power-generation/renewables/wind-power/Product-Sheet-HWRT.pdf.

[4] DEA, Information's from expert workshop held by DEA, 27-4-2015.

[5] In-house estimation of hourly power output from an offshore wind farm in the North Sea.

[6] The European offshore wind industry – key trends and statistics 2015, EWEA, 2016.

[7] Offshore Wind Cost Reduction Pathway Study, The Crown Estate, 2012.

[8] Master data register of wind turbines at end of December 2014, Danish Energy Agency (the analysis also utilize earlier years of the same register).

[9] The Danish offshore wind farm demonstration project: Horns Rev and Nysted offshore wind farms. Review report 2005, DONG Energy and Vattenfall, 2006.

[10] DTU International Energy Report – Wind Energy, DTU, 2014.

[11] Energy Technology Perspectives 2008, IEA, 2008.

[12] Renewable Energy Technologies: Cost Analysis Series, IRENA, 2012.

[13] B. Christensen, Interviewee, Personal communication/Interviews with Siemens Wind Power + written contribution. [Interview].

[14] Fremtidens havmølleplaceringer - 2025 (Future locations for offshore wind farms; in Danish)," Danish Energy Agency, 2007.

[15] Lindø Offshore Renewables Centre, data on offshore wind farms.

[16] 4 C Offshore, global offshore wind farms database [Online]. Available: http://www.4coffshore.com/windfarms/default.aspx.

[17] Fichtner/Prognos, Cost Reduction Potentials of Offshore Wind Power in Germany, 2013.

[18] DENMARK - SUPPLIER OF COMPETITIVE OFFSHORE WIND SOLUTIONS, Megavind, 2013 May.
[19] Catapult, Crown Estate.
[20] DENMARK - SUPPLIER OF COMPETITIVE OFFSHORE WIND SOLUTIONS, TKI Wind Op Zee, 2015.
[21] Wind energy scenarios for 2030, EWEA, 2015.
[22] 2015. [Online]. Available: http://www.windprospecting.com/.
[23] [Online]. Available: http://www.wind-power-program.com/turbine_characteristics.htm .
[24] Energiaftalen, 2012.
[25] Aftale om tilbagerulning af FSA mv. og lempelser af PSO, 14. juli 2014.
[26] The Economics of Wind Energy, EWEA, 2009.
[27] N. m.fl., Vindmøllers økonomi, EUDP projekt 33033-0196, 2010.
[28] Costs of low carbon generation technologies, Commitee on Climate Change & Mott MacDonald, 2011, 9 May.
[29] E. I. a/s, http://www.windprospecting.com/, 2015.
[30] http://www.4coffshore.com/windfarms, accessed 27-3-2017
[31] Note made by DEA: "Notat om teknologiomkostninger for havvind, baggrund for opdatering af CAPEX og OPEX i Teknologikatalogets dataark". Energinet and the Danish Energy Agency, 2017, March 28.
[32] DONG ENERGY Investor presentation, , DONG Energy, 2016, 12 May
[33] Cost Reduction Monitoring Framework 2016,Offshore Wind Programme Board, Catapult 2016, 2016
[34] Innovation Outlook: Off shore Wind, International Renewable Energy Agency (IRENA), Abu Dhabi, 2016
[35] Energinet, March 2017

22 Photovoltaics (for qualitative description go to previous catalogue)

This chapter is under review.

Until then please look at the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

The datasheet for large scale utility system photovoltaics has been updated in October 2017 and can be found here below. A note (in Danish) documenting the updating can be found at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Author: EA Energy

Publication date

October 2017

Amendments after publication date

Date	Ref.	Description

Technology	Photovoltaics: LARGE scale utility systems					
	2015	2020	2030	2050	Note	Ref
Input						
Global horizontal irradiance (kWh/m2/y)	1,068	1,068	1,068	1,068	A	4
Energy/technical data						
Typical capacity for one installation (kW)(plant capacity)	4,000	4,000	4,000	4,000	B	
Typical peak capacity for one installation at STC (kWp)	5,400	5,400	5,400	5,400	C	
Energy/technical data - system design						
DC/ACMAX sizing factor (Wp/W)	1.35	1.35	1.35	1.35	D	26
Transposition Factor for fixed tilt system	1.15	1.15	1.15	1.15	E	26
Incident Angle Modifier Loss (%)	3.0%	2.5%	1.5%	1.0%	F	13
PV systems losses and non-STC corrections (%)	13.0%	9.0%	7.0%	5.0%	G	
Inverter loss (%)	3.1%	2.6%	2.6%	2.1%	H, H2	13
AC grid losses (%)	1.0%	1.0%	1.0%	1.0%	I	
PV module conversion efficiency (%)	16.50%	19.0%	23.0%	26.0%		13
Availability (%)	100%	100%	100%	100%		
Technical lifetime of total system (years)	30	35	40	40		
Inverter lifetime (years)	10	15	15	15		

Output						
Full load hours (kWh/k W_{acmax})	1,340	1,420	1,460	1,510	J, L	
Peak power full load hours (kWh/kW_p)	990	1,050	1,080	1,120	K, L	
Financial data						
PV module (2015-€/W_p)	0.62	0.26	0.19	0.13	O	26
Inverter and transformer (2015-€/W_p)	0.10	0.05	0.03	0.02		26
Balance Of Plant , mark-up & contingency cost (2015-€/W_p)	0.36	0.31	0.29	0.26	O	26
Specific investment, total system (2015-€/ W_p)	**1.08**	**0.62**	**0.51**	**0.41**	M,N	26
PV module cost (€/W_{acmax})	0.84	0.35	0.25	0.17		26
Inverter and transformer(€/W_{acmax})	0.07	0.06	0.05	0.03		26
Balance Of Plant , mark-up & contingency cost (€/W_{acmax})	0.49	0.42	0.39	0.35		26
Specific investment, total system (€/W W_{acmax})	**1.46**	**0.83**	**0.69**	**0.56**	P	26
Fixed O&M (2015-€/MW_p /y)	9,500	8,100	6,500	5,500	Q, R, S	26
Fixed O&M (2015-€/MW W_{acmax}/y)	12,800	10,900	8,800	7,400		

Notes:

Data applies to utility PV installation typically mounted on the ground, with capacity of 1 MWp and larger, a maximum capacity limit is not set as solar systems are largely modular and the costs thus largely proportional to the size of the plant when the plant is larger than app. 1 MW

A. The global irradiation is a measure of the energy resource potential available and is depended on the exact geographical location. The average value in Denmark as determined among 25 measurement stations is 1068 (kWh/m2/y) ± 3.1 % (1 σ). The best sites demonstrate values around 1100 kWh/m2/y. A value of 1075 kWh/m2/y is used as the suggested reference value, considering that there is an incentive for PV developers to locate plants where the solar resource is best.
B. In 2017 a PV-plant with require an area of around 1.3 to 1.7 ha/MWp assuming a module coverage of 35% to 45% and panel size of 1.64 m2 for 275Wp, increasing efficiency will decreas the area requirements.
C. The peak power of the system is the max. power of the PV modules(DC).
D. The DC/AC shown in the table equals module peak capacity divided by plant capacity. The sizing factor is set to the same value for all years, as it is not the technical factors of the system, which determine the sizing factor. The sizing factor is chosen according to the desired utilisation/loading of the inverter which can also reflect a desire to maximise the energy production from a given (restricted) AC-capacity.
E. The transposition factor describes the increase in the sunlight energy that can be obtained by tilting the module with respect to horizontal and reduction in received energy when the orientation deviates from South. The TF factor is set to the same value for all years and sizes of the system, as it is not the technical factors of the system, which determine the TF.
F. The Incident Angle Modifier (IAM) loss represents the total yearly solar energy that is reflected from the glass when the angle of incidence is different from the perpendicular (the reflections at a normal incidence is already included in the STC efficiency).

G. These losses are calculated by simulating a model-year where corrections are made hour-by-hour due to the fact that the actual operation does not take place under STC conditions. Additionally, electrical losses in cables and combiner boxes are included.
H. The inverter loss includes the Maximum Power Point Tracking (MPPT) efficiency and is averaged over typical load levels.
H2 Losses related to the DCAC factor at DC/AC= 1.49 a production losses of 1,1 % is as assumed
I. Not relevant for small and medium size plants.
J. The number of full load hours is calculated based on the other values in the table. The calculation formula is: Full load hours = 1068 * sizing factor * transposition factor * (1-incident angle modifier loss) * (1-PV system losses etc.) * (1-inverter loss) * (1-AC grid loss).
K. Also known as the specific yearly energy production (kWh/kWp) of the PV modules. This value is calculated from this formula: Peak power full load hours = 1068 * transposition factor * (1-incident angle modifier loss) * (1-PV system losses etc.) * (1-inverter loss) * (1-AC grid loss).
L. Capacity factor = Full load hours / 8760.
M. Current market prices for utility scale PV systems have been estimated based on interviews with Danish developers and an assessment of the prices from Danish and Germany tenders for PV capacity in 2016 and the beginning of 2017. The price analysis is available in the note (in Danish) "Opdatering af teknologikatalogets solcelledata oktober 2017" (ref 26). The prices analysis also contains a forecast of the PV price, which based on estimated learning rates for the module and invester (20 % learning rate) and balance of plant (10 % learning rate) and a projection of the cumulated PV capacity based on the IEA's 450 ppm scenario. The share that the PV module and the inverter accounts for decreases over time as the result of the higher learning rate compared to the balance of plant.
N. The financial values have been discounted as shown in the table below
O. The investment for PV modules and the investment in Balance of Plant (BOP) are calculated from the value “specific investment, total system per Wp(DC)”. It is assumed that the share that the PV module accounts for is decreasing over time. And it is assumed, that the larger a PV system is, the higher the share of the total investment, the PV module will account for.
P. The “specific investment, total system per rated capacity W(AC)” is calculated as “specific investment, total system per Wp(DC)” multiplied by the sizing factor.
Q. The cost of O&M includes insurance and regular replacement of inverters and land-lease.
R. The cost of land lease amounts in 2017 to approx. 25% -30% of the total cost of O & M (per Wp). As the efficiency of the new solar panels increases, the lease per MWp will be lower, the same development will be seen for other O & M expenses, so it is expected that land lease for all years will amount to approx. 25-30% of the total cost of O & M.

Real prices	**2015**	**2016**	**2017**
BTV for price year (2015)	1.0000	1.0067	1.0249

References

1. NPD Solarbuzz PV Equipment Quarterly report, July 2013.
2. IEA PVPS Trends 2013 in Photovoltaic Applications – 2014 Edition, 2014/05/06 p. 53.
3. IEA,“Energy Technology Perspectives. Technology Roadmap: Solar Photovoltaic Energy, 2014 edition”, OECD/International Energy Agency, 2014.
4. Peter Riddersholm Wang, DMI Teknisk Rapport 13-08, Referenceværdier: Måneds- og årsværdier for

stationer 2001 - 2010, Danmark for temperatur, relativ luftfugtighed, vindhastighed, globalstråling og nedbør.
5. M.J. (Mariska) de Wild-Scholten. “Energy payback time and carbon footprint of commercial photovoltaic Systems”. Solar Energy Materials & Solar Cells 119 (2013) 296–305.
6. “Solceller. Dansk strategi for forskning, udvikling, demonstration og udbredelse” (Solar cells. A Danish strategy for research, development, demonstration and deployment), Danish Energy Agency, Energy Technology Development Programme (EUDP), and Energinet.dk, 2009.
7. Prices from; Solcellepriser.dk, pricelist small plants 15 cheapest plants used,
8. EIA report: “Levelized Cost of New Generation Resources” in the Annual Energy Outlook 2013, U.S. Energy Information Administration, January 2013.
9. P. Ahm and J. Vedde, “Large Scale PV Plants – Also in Denmark”. Project report, 2011.
10. IEA-ETSAP and IRENA Technology Policy Brief E11, January 2013.
11. Ubiquity Solar Inc. 2012, Extrapolation of PV module experience curve.
12. Pierre Verlinden. Trina Solar SKL presentation April 16th 2013.
13. IRTPV. International Technology Roadmap for Photovoltaic, Results 2013. March 2014.
14. Thibaut Lemonie. Assessing the real quality of PV modules. Photovoltaics Int. Aug 2011, p. 177.
15. M. Bolinger and S. Weaver. Utility-Scale Solar 2012. Lawrence Berkeley National Laboratory. September 2013.
16. IEA PVPS Task 14 reports.
17. HOFOR plan, plant in Guderup (websearch) and 2 other plants (anonymous, Jan Vedde 2014) all four large and DK.
18. David Feldman et al. Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections edition 2014. SUNSHOT U.S. Department of Energy, National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory , September 22, 2014
19. Websearch by Jan Vedde November 2014 Prices for seven small plants for sale in DK in November 2014,
20. http://www.photovoltaik-guide.de/pv-preisindex, “Photovoltaik-preisindex” PV system up to 100 kWp, average 2014.
21. Prices for nine large and medium size systems 2013-2014(Confidential).
22. Gaia solar, BIOFOS Rensningsanlæg Damhusåen, large system 2013.
23. Gaia solar general offer 250 kW system 2014.
24. Anonym DK EPC#1 offering 0.91 2014-€/Wp for MW projects in DK
25. Anonym DK EPC#1 offering 0.95 2014-€/Wp for MW projects in DK
26. Ea Energy Analyses, Danish Energy Agency and Energinet.dk. " Opdatering af teknologikatalogets solcelledata oktober 2017 ", oktober 2017.

23 Wave Energy (go to previous catalogue)

There are no plans to update this chapter.

For now please look at the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

40 Heat pumps

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk
Energinet.dk: Rune Grandal, rdg@energinet.dk
Author: Morten Hofmeister, PlanEnergi, mh@planenergi.dk

Publication date

August 2016

Amendments after publication date

Date	Ref.	Description
January 2018	40 heat pumps	Updated prices for auxiliary electricity consumption in data sheet

Qualitative description

Brief technology description

Heat pumps employ the same technology as refrigerators, moving heat from a low-temperature level to a higher temperature level. Heat pumps draw heat from a heat source (input heat) and convert the heat to a higher temperature (output heat) through a closed process; either compression type heat pumps (using electricity) or absorption heat pumps (using heat; e.g. steam, hot water or oil).

An important point regarding heat pumps is the ability to "produce" both heating and cooling. Hence, the "product" of a heat pump can be both heating and cooling – and at the same time.

When applied with the primary purpose of cooling, the cooling demand defines the capacity. When installed for cooling the heat pump will typically be the only cooling source, whereas when installed for heating it will in many cases be in combination with other sources that can provide the heat energy (e.g. at a district heating plant). However, the primary purpose of the heat pumps in the technology catalogue is heating. In this chapter the unit MW is referring to the heat output (also MJ/s) unless otherwise noted.

Heat pumps are utilized for industrial processes, individual space heating and district heat production.

The application of large heat pumps in district heating systems in Denmark may influence the development of the heat pumps globally – both the technology itself and the application. This is in opposite to the small scale heat pumps, where the Danish market is small compared to other markets, and therefore is not expected to influence the development of small scale heat pumps.

Compression heat pumps

For compression heat pumps, the practical heat output is usually 3 to 5 times (the coefficient of performance (COP)) the drive energy. This factor depends on the efficiency of the specific heat pump, the temperature of the heat source and the heat sink and the temperature difference between heat source and heat sink. The energy flow is illustrated in the Sankey diagram in figure 1 below:

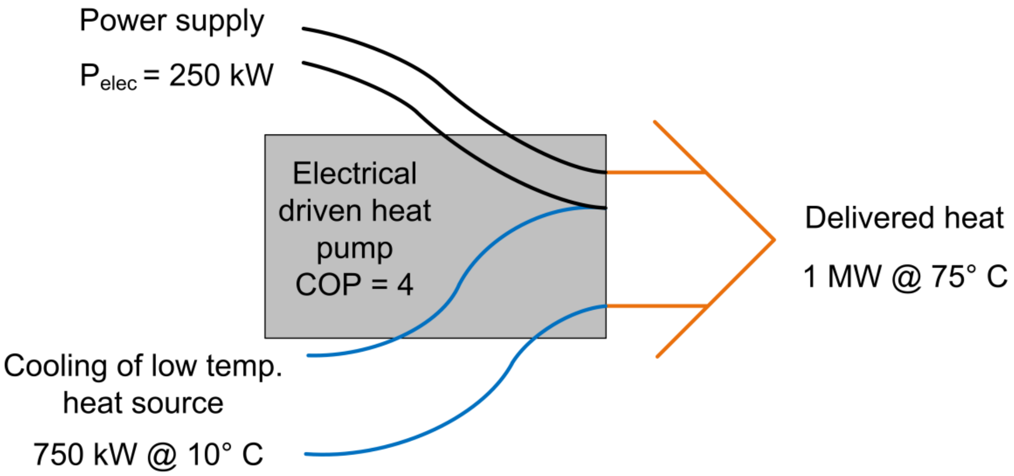
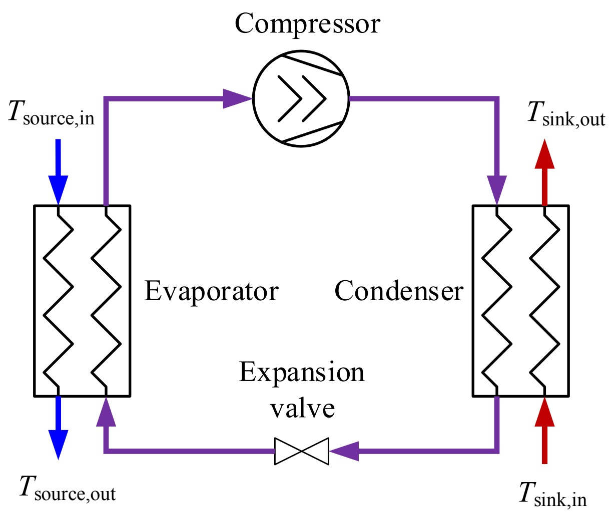


Figure 1: The electrical power consumption of 250 kW enables the heat pump to utilize 750 kW from a low temperature heat source at 10° C. Thus delivering 1 MW at 75° C (COP is 4).

The theoretical coefficient of performance can be calculated as the "Lorenz COP" which relates mechanical work to temperature differences in power generation, refrigeration and heat pump technology.



$$\mathrm{COP}_{\mathrm{Lorenz}} = \frac{T_{\mathrm{lm,sink}}}{T_{\mathrm{lm,sink}} - T_{\mathrm{lm,source}}} \quad , \qquad \text{where} \quad T_{\mathrm{lm}} = \frac{T_{\mathrm{in}} - T_{\mathrm{out}}}{\ln\left(\frac{T_{\mathrm{in}}}{T_{\mathrm{out}}}\right)}$$

Figure 2: Sketch of the heat pump cycle with components. The Lorenz COP is the theoretical maximum. (Source: Original figure from Bach (2014) "Integration of heat pumps in Greater Copenhagen").

A heat pump for district heating that heats water from 45 to 85° C (district heating) and cools a source from 20 to 15° C (cooling water from a factory), will have a theoretical maximum Lorenz COP of around 7.1.

In practice the COP will be lower due to mechanical and thermal losses, typically around 40-60 % of the theoretical COP. The relation between practical and theoretical COP depends on component efficiencies, heat exchangers, refrigerants and more. All COP-values stated in this document are practical values if nothing else is stated.

Possible practical COP values for large scale heat pumps are shown in figures 3, 4 and 5 below. The figures show the possible span of COP-values (max. and min. i.e. 40% and 60% losses) depending on the delivery temperatures in the system. The values are calculated with a heat source that is cooled 5° C – e.g. a heat source of 30° C is cooled to 25° C. Increasing the cooling of the heat source will lead to a lower COP, but a higher capacity.

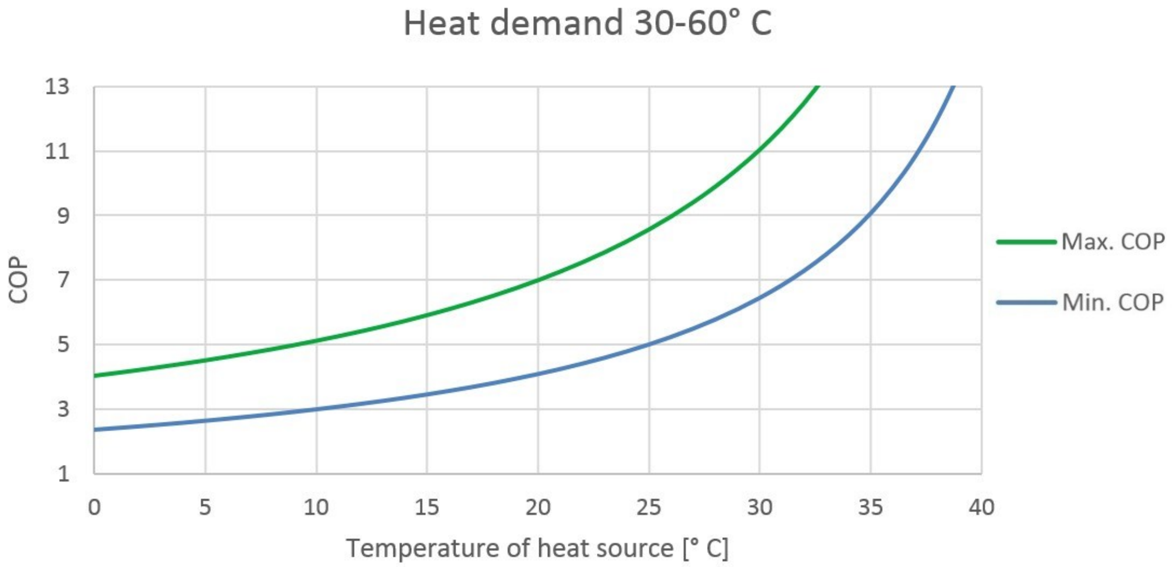


Figure 3: COP values of compression heat pump heating water from 30 to 60° C. For a heat source @ 0° C that is cooled to -5° C typical COP values will be 2.4-4.0 rising to 6.5-11 for a heat source @ 30° C that is cooled to 25° C [1].

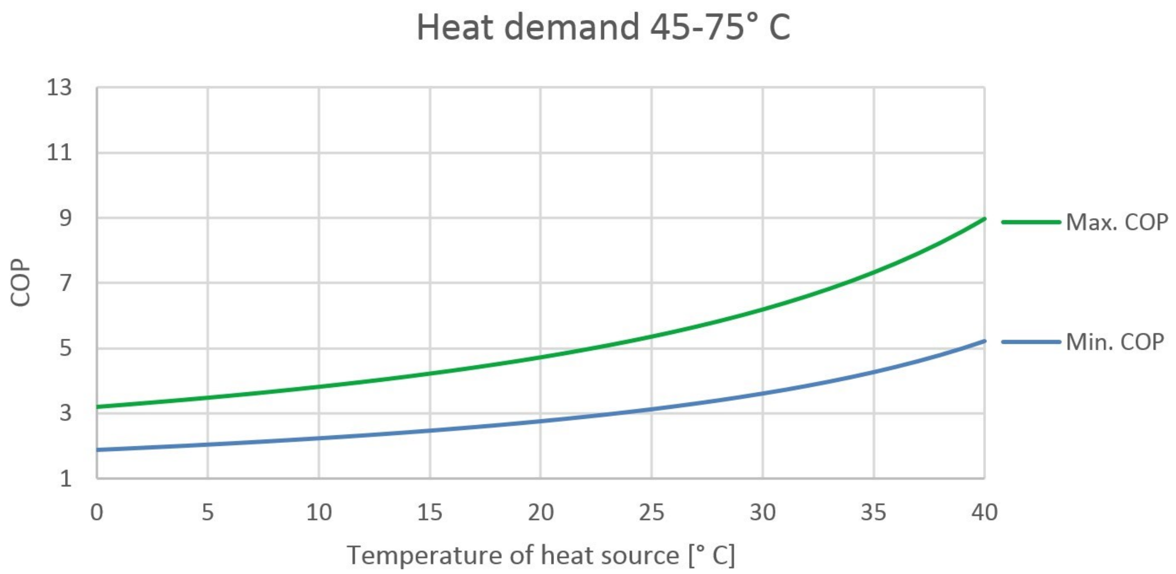


Figure 4: COP values of compression heat pump heating water from 45 to 75° C. For a heat source @ 0° C that is cooled to -5° C, typical COP values will be 2.0-3.1 rising to 5.0-9.0 for a heat source @ 40° C that is cooled to 35° C [1].

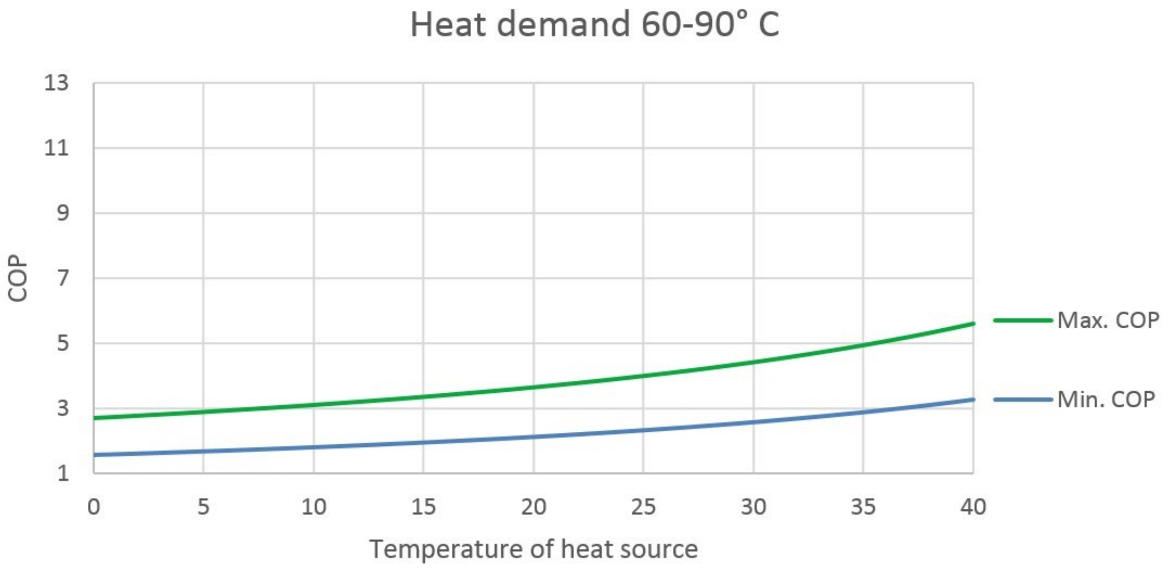


Figure 5: COP values of compression heat pump heating water from 60 to 90° C. For a heat source @ 0° C that is cooled to -5° C, typical COP values will be 1.6-2.7 rising to 3.2-5.6 for a heat source @ 40° C that is cooled to 35° C [1].

As the figures indicate, low temperature differences between source and sink are key to high COP values. Heat pumps are typically not profitable for high temperature heat demands where low temperature sources are utilized. Hence such heat pumps are unlikely to be on the marked.

Absorption heat pumps

In absorption heat pumps, high temperature heat is used to regenerate a refrigerant that can evaporate at a low temperature level and hereby utilize low grade energy. Energy from both drive heat and the low temperature heat source is delivered at a temperature in between. In theory 1 kJ of heat can regenerate around 1 kJ of refrigerant meaning that an absorption heat pump has a theoretical maximum COP of around 2. Due to losses in the system the practical COP is around 1.7. For absorption heat pumps, COP is not affected by temperature levels. Certain temperature differences is required to have the process going, but as long as these are met the COP will be around 1.7 and not affected by further temperature increase of the drive energy.

The energy flow is illustrated in the Sankey diagram in figure 6:

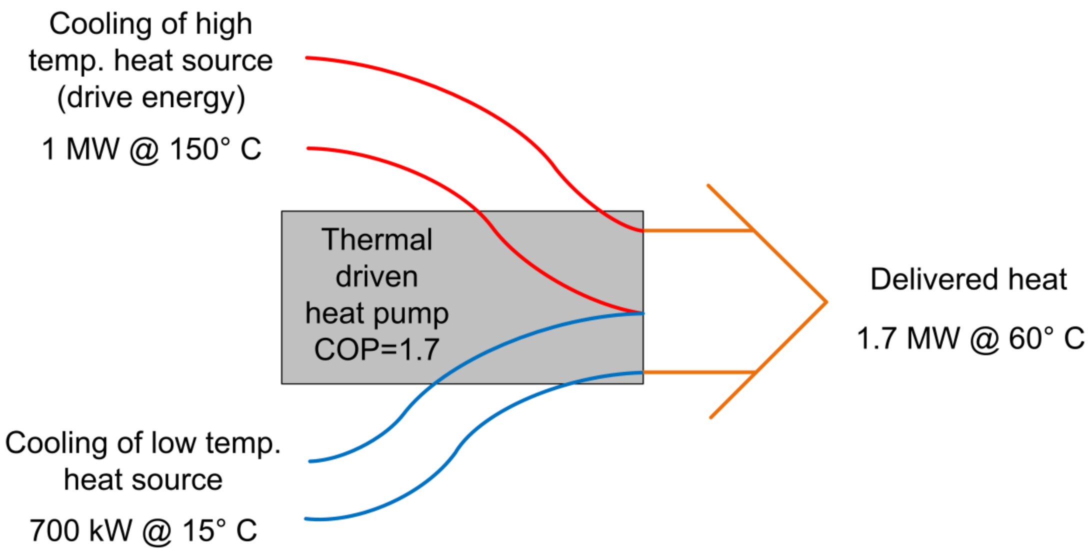


Figure 6: The high temperature drive energy of 1 MW enables the heat pump to utilize 700 kW from a low temperature heat source at 15° C. Thus delivering 1.7 MW at 60° C (COP is 1.7).

Two-stage versions are available for particular high driving temperatures. In two-stage absorption heat pumps, the drive energy is used twice enabling the heat pump to utilize almost twice as much low-grade energy. The practical COP of two-stage systems is typically 2.3.

Input

Inputs for heat pumps are a heat source and drive energy.

Heat sources can be ambient air, surface water or groundwater, ground (soil) or surplus heat from industries. Typical Danish temperatures are 0-18 °C as ambient air temperatures and 5-10 °C as groundwater temperature, whereas waste heat from industrial processes has much higher temperatures – sometimes enabling direct heat recovery. In some cases the input heat is delivered through a secondary water or glycol circuit but for optimum performance the heat source should be connected directly to the evaporator of the heat pump.

Drive energy for compression heat pumps are electricity (or engines consuming fuel), whereas absorption heat pumps are driven by heat; e.g. steam, hot water or flue gas, but also consume a small amount of electricity.

Output

The only output of a heat pump is heat. For large scale heat pumps the heat will typically be delivered to the end user through a water based distribution system.

The maximum delivery temperature differs according to type (compression or absorption heat pump) and also within either type depending on the actual refrigerant, design pressure and more. Most compression heat pumps will reach temperatures of around 80-90° C, whereas special types can reach up to 100-110° C. Absorption heat pumps are limited to around 85-87° C but the specific delivery temperature depends on the temperature of the heat source.

This is further outlined in the section "Development perspectives and future demand".

Typical capacities

Large scale compression heat pumps that are utilized in Denmark are available in capacities of up to around 3-5 MW heat output. Depending on the delivery temperature, larger heat pumps of more than 3-5 MW will typically be a number of heat pump units in parallel. In other countries where HFC refrigerants are permitted in large systems it is possible to use turbo compressors meaning that heat pumps with a heating capacity of 25 MW or more exist.

Absorption heat pumps are available in capacities of up to around 12 MW of cooling. The heat output including drive energy will thus be around 20 MW.

Regulation ability and other power system services

Regulation ability is a topic currently being investigated in several projects.

As today's market is very limited, large scale heat pumps are not constructed for very fast start/stop or load changes. Using adequate secondary water systems and control methods around the heat pump can enable most large scale heat pumps to fast starts and stops. In practice, the possibilities will depend on the specific heat pump construction and system requirements as outlet temperatures, efficiencies and more will be affected from fast load changes.

A frequency controlled heat pump has more components than on/off controlled heat pumps. This may increase the price.

Advantages/disadvantages

A general advantage of heat pumps is that the heat pump is able to recycle waste heat or utilize energy from the ambient which enables a utilization of heat sources otherwise left unused by conventional heat production technologies.

In energy systems where electricity plays a vital role, compression heat pumps can incorporate electricity in heating systems in an effective manner. For processes that are electrically heated, heat pumps reduce power consumption and load on the electrical grid.

Compression heat pumps that are electrically driven have no emissions from burning fuel, meaning that these systems can be installed in locations with restrictions on exhaust emissions.

Absorption heat pumps are able to utilize the energy quality of high temperature heat sources that are otherwise wasted when for instance a boiler is used to heat water up to 70 or 80 °C. In such applications, absorption heat pumps are able to exploit heat from the boiler at a higher temperature to recover heat from a lower temperature, thus reducing fuel consumption by approximately 40 %.

Compared to traditional heating technologies, heat pumps utilize a different working principle that is yet unfamiliar to parts of the heating industry. In order to reach the highest efficiencies, heat pumps are very dependable on low delivery temperatures and high temperatures of the source. This means that heat pumps are not suitable in all applications.

The heat source must be available and suitable according to the required heat demand. Changes in flow or temperature of the heat source will affect the performance of the heat pump, which can increase the complexity of a heat pump system.

Compared to most of the traditional heat production systems, heat pumps in general have higher investment costs, and lower energy consumption costs.

Environment

The primary environmental impact of heat pumps stems from the drive energy consumption and depends on the fuel type and production method. Absorption heat pumps are typically applied where fuel is already burned, meaning that the absorption heat pumps does not increase fuel consumption, but simply increase the heat output of an existing energy consumption.

As Danish legislation prevents synthetic refrigerants in circuits with more than 10 kg of refrigerant, heat pumps with a capacity of more than 60-80 kW utilize natural refrigerants meaning that toxicities from leaks are well known and greenhouse emissions from refrigerants are negligible.

Because of the Danish regulation, only natural refrigerants are utilized in Denmark. These are hydrocarbons (propane, butane and iso-butane), carbon dioxide, ammonia, and water vapour.

Ammonia is a widely applied natural refrigerant that can be dangerous to mammals and especially aquatic life forms. Because of this, ammonia systems must comply with certain safety measures regarding construction, location and operation. Other natural refrigerants are highly flammable but not environmentally harmful.

Research and development perspectives

In most countries the development within refrigeration moves towards natural refrigerants. The European F-gas regulation excludes the most harmful synthetic refrigerants and ensures that others are phased out during the coming years.

Danish regulation is even stricter by not allowing synthetic refrigerants in refrigeration units or heat pump installations holding more than 10 kg of refrigerant. Water vapor systems are not yet commercially available, but several demonstration projects are being initiated, meaning that low temperature systems will be demonstrated through the coming years. A new compressor type has been developed for cooling applications or as low stage circuit for heat pumps e.g. an H_2O system recovering heat from sea water at 0° C and delivering at 20° C, while an ammonia system takes the temperature from 20° C and delivers at a higher temperature. The technology has a number of advantages especially regarding utilization of low temperature water sources such as sea water, and is expected to play a vital role in large scale heat pumps for district heating.

Other areas of technology development are:

- Higher outlet temperatures
- Combinations of the different technologies, e.g., H_2O – NH_3 etc.
- Optimise the benefits for the overall electricity system of using heat pumps
- Intelligent integration in energy systems to increase overall system efficiency

- New control systems for higher flexibility and better system integration

Examples of market standard technology

Depending on size and temperature requirements, different types of heat pump technology can be the best choice and no single refrigerant is valid for all applications.

The best solutions are often multi-stage plants that will both cool and heat in steps to minimize thermal losses. Oil coolers, de-superheaters and subcoolers are utilized to minimize pressure differences and hereby the mechanical work required. High efficiency motors are applied, preferably cooled by water or refrigerant and heat from frequency converters are sometimes utilized as well.

As mentioned earlier the different refrigerants can be applied, depending on the specific requirements regarding temperature demand, capacity as well as practical issues.

CO_2 heat pumps operate in the so-called trans-critical pressure range, meaning that the refrigerant has a temperature glide on the warm side while the cold side evaporates at a constant temperature. This means that CO_2 is particularly suited in applications where heat is drawn from a low temperature source by cooling it only a few degrees, while the delivered heat is provided at a temperature glide of maybe 40° C. The maximum outlet temperature of CO_2 systems is app. 90° C. In order to obtain good COP values in CO_2 systems the inlet temperature of the heated media should not be higher than app. 40° C. Examples of installed plants using CO_2 as refrigerant:

Jensens Køkken, Denmark 200 kW – max. temperature of 80° C

Marstal Fjernvarme, Denmark - 1.5 MW – max. temperature of 75° C

Ammonia is a widely used refrigerant for industrial refrigeration meaning that large scale equipment with high efficiencies can be utilized for the heat pumps. Ammonia is typically used for the largest plants reaching up to around 95° C utilizing special components for high pressure levels. Ammonia is also suitable for lower temperature levels where standard components are utilized meaning less investment cost and high COP values. Examples of installed plants using ammonia as refrigerant:

Drammen District Heating, Norway - 15 MW – max. temperature of 90° C

Skjern Paper Mill, Denmark – 4 MW – max. temperature of 90° C

Bjerringbro District Heating, Denmark, 3.7 MW – max. temperature of 70° C

Hybrid H_2O/NH_3 heat pumps combine the absorption and the vapour compression cycles, hence the name hybrid. Ammonia is used as refrigerant but absorbed by H_2O thus at reduced working pressure meaning that standard components can be used for high temperatures. The maximum temperature in systems in operation is around 90° C but it should be possible to reach higher temperatures using the same components. Examples of installed plants, hybrid using H_2O/NH_3 as refrigerant:

Nortura Dairy, Norway – 0.65 MW – max. temperature of 85° C

Arla Dairy, Denmark – 1.2 MW – max. temperature of 85° C

Hydrocarbons are primarily used in medium sized applications where either propane or isobutene is used as refrigerant. These refrigerants can be used with standard components from commercial refrigeration meaning that investment costs are kept at a low level. Propane can reach temperatures of 65° C whereas isobutene can reach temperatures of around 85° C. These refrigerants are flammable meaning that heat pumps are often delivered in a special cabinet and installed outdoors. Examples of installed plants using Hydrocarbons as refrigerant:

GKN Wheels, Denmark – 1.1 MW – Propane, max. temperature of 65° C

Birn, Denmark – 1.2 MW – Propane, max. temperature of 65° C

Skejby Sygehus, Denmark – 0.2 MW – max. temperature of 85° C

LiBr/Water is used in absorption heat pumps whereas ammonia/water is typically used in absorption cooling systems. Water is the refrigerant meaning that the gauge working pressure is negative. The lowest possible temperature on the source side is around 6° C while the sink temperature can be up to around 85° C. The different temperatures influence each other meaning that a low source temperature can limit the delivery temperature for the heat sink.

For higher temperature lifts, it is possible to buy absorption plants where two systems are built in to one and connected in series to increase the temperature lift. Examples of installed LiBr/Water plants:

Bjerringbro District Heating, Denmark, 0.9 MW (cooling) – max. temperature of 70 °C

Vestforbraending, Denmark – 13 MW (cooling) – max. temperature of 80 °C

Prediction of performance and costs

Learning curves express the idea that each time a unit of a particular technology is produced, some learning accumulates which leads to cheaper production of the next unit of that technology. Hence, there are two dimensions of learning curves; the application of the technology and the technology itself.

The technology development perspective has the same two dimensions; the application and the technology itself. Both dimensions influence the parameters including the efficiency of a heat pump in operation. The application dimension has a larger potential for improvement than the technologies themselves. The estimate of the development perspectives in the data sheets is the total potential, i.e. both dimensions.

With reference 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 [2]. 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 innovation can be expected to take place faster than in a situation with less ambitious policies.

In Danish, European and to some extent also global contexts, there is increased focus on energy efficiency (Danish Energy Policy, European Energy Union and Energy Efficiency Directive). Heat pumps can be a tool to increase the energy efficiency. Therefore, a significant market-pull can be expected regarding heat pumps.

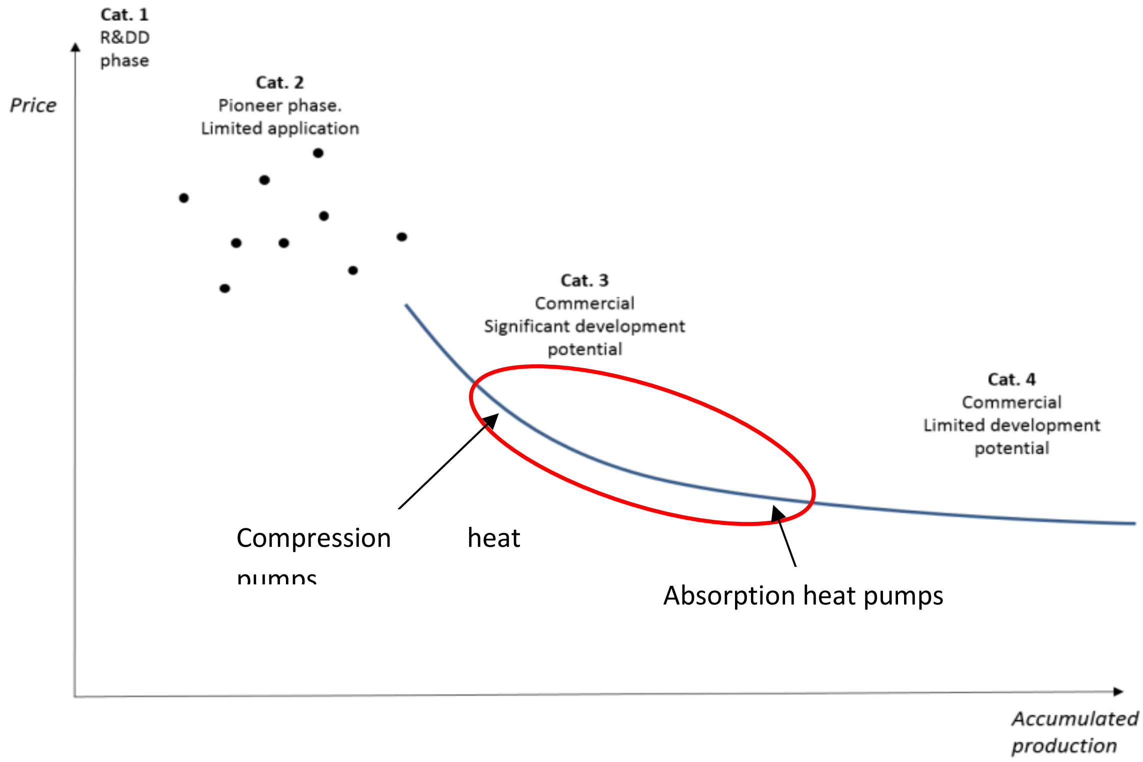


Figure 7: Learning curves of heat pumps for district heating production.

Large scale heat pumps belong in Category 3: "Commercial technologies with moderate deployment so far and significant development potential". It is expected that there is a potential for reducing cost of large scale heat pumps. The potential for increased efficiencies of the heat pump itself is limited as the best large scale heat pumps are already very efficient. However it is possible to integrate heat pumps in a more effective manner and to improve the practical COP value. This could lead to installations with high COP values. Absorption heat pumps are more common than compression types, meaning that the development potential is lower.

Large scale compression heat pumps derive from industrial refrigeration applying the same principles and a lot of the same components. However, heat pumps require a higher working pressure meaning that some of the main components are special for heat pumps which limits the supply range. Large scale heat pumps are still rare compared to industrial refrigeration, meaning that the production numbers for certain components are low.

Most heat pump plants today are custom built requiring a high amount of engineering in each case. One reason being the low number of installed heat pumps. As more plants will be constructed, it is expected that engineering will be systemized and calculation tools will be developed to ensure swift specification and construction.

As stated above, the low production numbers of heat pumps leaves a potential for cost reduction. Ideally the prices could match equipment for industrial refrigeration in the future.

Absorption heat pumps are more widely spread and because of this, the potential of reduced investment costs are lower than for compression heat pumps. At the moment development primarily concerns size optimization (reduction of footprint), which is more of a barrier than investment cost.

Based on the above mentioned the following assumptions regarding accumulated volume and cost reduction for investment and maintenance for heat pumps are introduced.

Increase in accumulated produced units	2015-2020	2020-2030	2030-2050
Compression heat pumps	0,8	1,25	1,25
Absorption heat pumps	0,5	0,8	0,8

Table 1: Assumed increase in the accumulated produced units in the different time periods.

Reduction in cost	2015-2020	2020-2030	2030-2050
Compression heat pumps	6%	10%	10%
Absorption heat pumps	4%	6%	6%

Table 2: Resulting reduction in cost in the different time periods, it is for both types it is assumed that the cost is decreased 7-8% for every doubling.

Energy efficiency and COP

Regarding energy efficiency, the mechanical work of compression heat pumps relates to the temperature difference between heat source and sink. As stated in the first section, a theoretical COP can be calculated from the temperatures in the system, whereas an actual COP further relates to mechanical losses and thermal losses within the system. The difference between the theoretical and the actual COP value is the efficiency of a specific system.

As the practical efficiency depends on both mechanical and thermal losses, it is expected that the efficiency will only increase a few percentage points during the next years. It is however expected that heat pumps with higher COP values will be installed but this will be due to better system integration.

No matter how much the individual components are optimized, there will always be a large increase in the COP when energy is absorbed at the highest possible temperature and delivered at the lowest possible temperature.

Temperature differences can be reduced by optimizing the system (e.g. lowering temperatures in district heating systems), eliminating secondary circuits, utilizing multistage heat pump systems, coproduction with other heat production units etc. The significance of system temperatures is visualized on figure 3, 4 and 5.

Uncertainty

Future development of investment costs and performance is quite uncertain as these parameters are valued against fuel and electricity cost.

If electricity cost increase it would be profitable to buy a more expensive heat pump with better performance.

Costs of fuels affect the competitiveness of heat pumps. E.g. expensive biomass, gas or oil will imply that heat pumps will be better alternatives even with low COP values.

Hence, the competitiveness of heat pumps is not only determined by the improvement of efficiency of heat pump technology and installation, but also the development of efficiency of competing technologies, market prices, taxes and subsidies on energy sources including electricity.

One method to navigate in this uncertainty is to refer to official scenarios for the development of energy prices issued regularly by the Danish Energy Agency.

In a concrete project context uncertainty can be mitigated by applying the calculation tool developed in [3] which enables an initial assessment of the feasibility of a heat pump based on key data for a specific plant.

Economy of scale effects

The effect of economy of scale is limited for large scale heat pump plants. Due to limitations in component sizes, many components are often duplicated meaning that scale effects are limited. Capacity increase of 100 % typically increase price by 70-90 %.

Additional remarks

A key point regarding application of the data in the data sheet is that e.g. the practical COP may vary considerably depending on the specific temperatures.

The following types and sizes are covered in this technology sheet:

- Large heat pumps for district heating systems, heat source ambient temperature
- Large heat pumps for district heating systems, heat source 20°C
- Large heat pumps for district heating systems, heat source 40°C
- Large single effect absorption heat pumps

In the technology sheets, two tracks for the future district heating supply temperature are assumed, these are:

Assumed supply temperature in each track	2015	2020	2030	2050
Track: No development in supply temp.	40 – 80°C			
Track: Reduced supply temp.	40 – 80°C	40 – 75°C	35 – 70°C	30 – 60°C

Data sheets

Technology	40 Electrical compression heat pumps - district heating									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Heat generation capacity for one unit (MW_{heat})	4	4	4	4	3	6	3	10		3
Total efficiency, net (%), name plate	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Total eff., net (%), annual average, ambient heat source, no dev. in supply temp.	350	360	380	410	350	380	350	450	A, F, J, K	4
Total eff., net (%), annual average, ambient heat source, reduced supply temp.	350	400	480	600	350	450	350	700	A, B, F, J	3, 4
Total eff., net (%), annual average, waste heat 20° C, reduced supply temp.	440	500	600	740	440	600	440	850	A, B, F, J	3, 4
Total eff., net (%), annual average, waste heat 40° C, reduced supply temp.	700	900	1200	1800	700	1200	700	2000	A, B, F, J	3, 4
Electricity consumption for pumps etc. (% of heat gen)	2	2	2	2	1	4	1	4	I, M	3
Forced outage (%)	0	0	0	0	0	1	0	1	G	3
Planned outage (weeks per year)	0,5	0,5	0,5	0,5	0	1	0	1	H	3
Technical lifetime (years)	25	25	25	25	15	30	15	30		3
Construction time (years)	0,5	0,5	0,5	0,5	0,3	0,7	0,3	0,7	C	
Space requirement (1000m2 per MW_{heat})	0,02	0,02	0,02	0,02	0,01	0,04	0,01	0,04		1
Regulation ability										
Primary regulation (% per 30 seconds)	10	10	10	10	10	25	10	30	D	3
Secondary regulation (% per minute)	20	20	20	20	20	40	20	40	D	3
Minimum load (% of full load)	10	10	10	10	10	10	10	10	D	3
Warm start-up time (hours)	0	0	0	0	0	1	0	1		3
Cold start-up time (hours)	6	6	6	6	1	12	1	12	E	8,10
Environment										
SO_2 (g per GJ fuel)	0	0	0	0	0	0	0	0		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0	0		
CH4 (g per GJ fuel)	0	0	0	0	0	0	0	0		
N2O (g per GJ fuel)	0	0	0	0	0	0	0	0		
Financial data										
Nominal investment (M€ per MW_{heat})	0,70	0,66	0,59	0,53	0,50	1,00	0,50	1,00	A, L	
- of which equipment (%)	50	50	50	50	30	70	30	70		3
- of which installation (%)	50	50	50	50	30	70	30	70		3
Fixed O&M (€/MW_{heat}/year)	2000	2000	2000	2000	1000	3000	1000	3000		3
Variable O&M (€/MWh_{heat})	3,3	3,2	3,7	3,9	2,2	4,8	2,7	6,7		
- of which is electricity costs (€/MWh_{heat})	1,3	1,4	2,0	2,3	0,7	2,8	1,2	4,7	M	
- of which is other O&M costs (€/MWh_{heat})	2,0	1,8	1,7	1,6	1,5	2,0	1,5	2,0	F	3

Notes

A. Actual development within COP optimization and reduced investment cost depends on the development in fuel and electricity prices.

B The large potential for higher COP factors is primarily caused by lower supply temperatures in the future (40-80 °C in 2015 and 30-60 °C in 2050)

C. The development within construction time will depend on future production figures and standardization of plants.

D. The regulation ability of large heat pumps will depend on the future markets for regulation services.

E. Cold start of time is starting a heat pump where stand by heating has not been applied

F. Operation at part load will usually increase COP but increase variable O&M costs

G. May vary depending on availability of heat source

H. May vary depending on specific type, heat source etc.

I. The auxillary eletricity is not included in the total efficiency

J. The total efficiency net annual average is calculated using the practical COP

K. Average value for ambient heat sources. For air it will be lower and for sea and lake water it will be around the average value, whereas for groundwater the value will be higher. It is weighted so that the heat pump produces 60-70 % of the demand of the district heating system. The supply temperature from the heat pump is fairly constant, since it is mixed with water from other production units in the months with the highest heat demand, when the supply temperature in the network is typically increased.

L. Including heat uptake and buildings

M. The cost of auxiliary electricity consumption is calculated using the following electricity prices in €/MWh: 2015: 63, 2020: 69, 2030: 101, 2050: 117. These prices include production costs and transport tariffs, but not any taxes or subsidies for renewable energy.

Technology	40 Absorption heat pumps - district heating									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Heat generation capacity for one unit (MW_{heat}) (excluding drive energy)	12	12	12	12	12	20	12	30	A	13
Total efficiency, net (%), name plate	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Total efficiency , net (%), annual average	170	171	173	175	170	180	170	180	B	4
Electricity consumption for pumps etc. (% of heat gen)	1	1	1	1	1	3	1	3	E	3
Forced outage (%)	0	0	0	0	0	1	0	1	C	
Planned outage (weeks per year)	0	0	0	0	0	1	0	1	D	
Technical lifetime (years)	25	25	25	25	15	30	15	30		3
Construction time (years)	0,5	0,5	0,5	0,5	0,3	0,7	0,3	0,7		
Space requirement (1000m2 per MW)	0,01	0,01	0,005	0,005	0,005	0,01	0,005	0,01		
Regulation ability										
Primary regulation (% per 30 seconds)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Secondary regulation (% per minute)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Minimum load (% of full load)	10	10	10	10	10	10	10	10		
Warm start-up time (hours)	0	0	0	0	0	1	0	1		
Cold start-up time (hours)	0,5	0,5	0,5	0,5	0,25	2	0,25	2		
Environment										
SO_2 (g per GJ fuel)	0	0	0	0	0	0	0	0		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0	0		
CH4 (g per GJ fuel)	0	0	0	0	0	0	0	0		
N2O (g per GJ fuel)	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0		
Financial data										
Nominal investment (M€ per MW_{heat}) (excluding drive energy)	0,6	0,56	0,51	0,46	0,4	0,8	0,4	0,8	A	3
- of which equipment (%)	50	50	50	50	30	70	30	70		3
- of which installation (%)	50	50	50	50	30	70	30	70		3
Fixed O&M (€/MW_{heat}/year)	2000	2000	2000	2000	1000	3000	1000	3000		3
Variable O&M (€/MWh_{heat})	0,9	1,0	1,3	1,4	1,0	2,5	1,4	0,3		
- of which is electricity costs (€/MWh_{heat})	0,6	0,7	1,0	1,2	0,7	2,1	1,2	0,0	E	
- of which is other O&M costs (€/MWh_{heat})	0,30	0,28	0,25	0,23	0,30	0,40	0,20	0,30		3

Notes

A. The heat pump itself only represents a small part of the total investment. Depending on size the heat pump typically represents 0.2 M€ per. MW heating (excluding drive energy).

B The heat is assumed delivered at 80 °C in 2015 and 60 °C in 2050.

C. May vary depending on availability of heat source.

D. May vary depending on specific type, heat source etc.

E. The cost of auxiliary electricity consumption is calculated using the following electricity prices in €/MWh: 2015: 63, 2020: 69, 2030: 101, 2050: 117. These prices include production costs and transport tariffs, but not any taxes or subsidies for renewable energy.

References

[1] Teknologisk Institut, 2015.

[2] Energy Technology Perspectives 2012, IEA, 2012.

[3] Drejebog til store varmepumpeprojekter i fjernvarmesystemet, 2014. [Online]. Available: http://www.planenergi.dk/varmepumper/.

[4] Udredning vedrørende varmelagringsteknologier og store varmepumper til brug i fjernvarmesystemer, 2013.

[5] K. E. Herold, R. Radermacher og S. A. Klein, Absorption chillers and heat pumps, 1996.

[6] Advansor, 2015.

[7] Hybrid Energi, 2015.

[8] Innoterm, 2015.

[9] Cronborg, 2015.

[10] Johnson Controls, 2015.

[11] Udredning vedrørende varmelagringsteknologier og store varmepumper til brug i fjernvarmesystemer, 2013.

[12] Energinet.dk, 2015.

[13] Scandinavian Energy Group, 2015.

41 Electric Boilers

Contact information:

Energinet.dk: Loui Algren, loa@energinet.dk
Author: Morten Hofmeister, PlanEnergi, mh@planenergi.dk

Publication date

June 2017

Amendments after publication date

Date	Ref.	Description
June 17	41 Electric boilers	Chapter from previously catalogue revised and added
January 18	41 Electric boilers	Updated prices for auxiliary electricity consumption in data sheet

Qualitative description

Brief technology description

Electric boilers are devices in the MW size range using electricity for the production of hot water or steam for industrial or district heating purposes. They are usually installed as peak load units in the same way as an oil or gas boilers. Hence, the following description of electric boilers is based on an operation strategy, aiming at approx. 500 full-load hours/year.

The conversion from electrical energy to thermal energy takes place at almost 100 % efficiency. However, from an exergetical point of view, this technology should be justified by its systemic advantages. Cf. electric water heaters can be a part of the energy system facilitating utilization of wind energy and enabling efficient utilization of various heat energy sources.

Thus, the application of electric boilers in district heating systems is primarily driven by the demand for ancillary services rather than the demand for heat. Although, examples of electric boilers, that operate on the spot market can be found.

Generally, two types of electric boilers are available:

- Heating elements using electrical resistance (same principle as a hot water heater in a normal household). Typically, electrical resistance is used in smaller applications up to 1-2 MW. These electric boilers are connected at low voltage (e.g. 400 or 690 V, depending on the voltage level at the on-site distribution board).
- Heating elements using electrode boilers. Electrode systems are used for larger applications. Electrode boilers (larger than a few MW) are directly connected to the medium to high voltage grid at 10-15 kV (depending on the voltage in the locally available distribution grid).

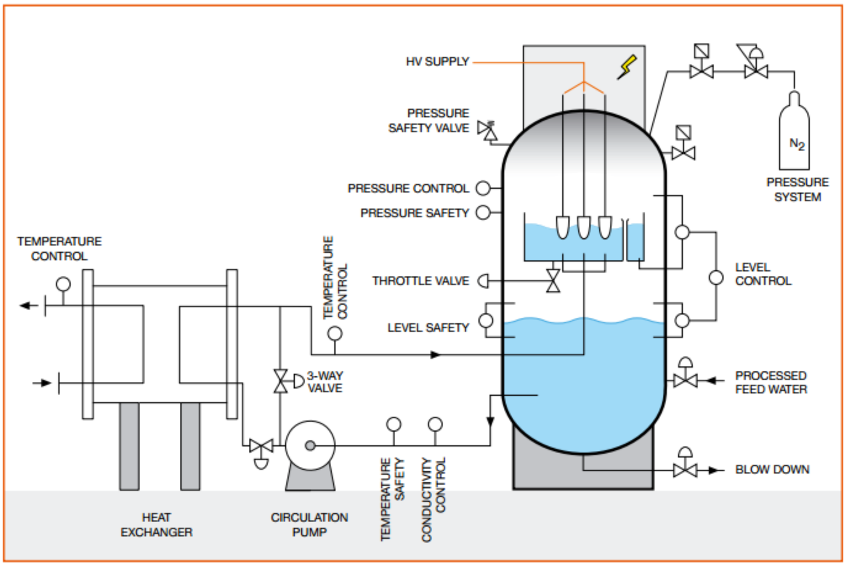


Figure 1: Schematic illustration of an electrode boiler. The heat is generated in the upper chamber through ohmic resistance between the electrodes. The boiler is pressurized with an inert gas system, e.g. nitrogen. [3]

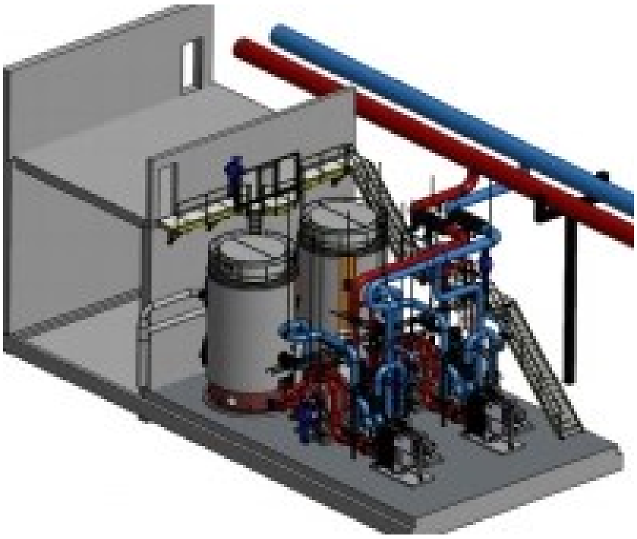


Figure 2: Illustration of 2x40 MW electric boilers installed at Studstrup power plant. The heat exchangers in front of the electric boilers transfer the heat from the water circuit in the boiler to the district heating circuit (blue/red piping). [9]

The water in electrode boilers is heated by means of an electrode system consisting of (typically) three-phase electrodes, a neutral electrode and a water level & flow control system. When power is fed to the electrodes, the current from the phase electrodes flows directly through the water in the upper chamber, which is heated in the process. The heat production can be varied by varying the flow through the upper chamber and the power that is led through, thus enabling output to be controlled between 0 and 100 %. [3]

In a similar technology, the heat output is varied, by varying the contact area between water and electrodes, by covering the electrodes in control screens. Thus the contact area between water and electrodes can be varied by varying the water level around the electrodes.

In both technologies, there will be no high-voltage consumption in a stand-by situation, as the only stand-by consumption is due to circulation pumps, which lies in the range of 5 % of full load.

Input
Electricity.

Output
Heat (hot water).

Typical capacities
Resistance-boilers are available in the span 6-5.000 kW/unit.

Electrode boilers are available in the seamless span 0-60 MW/unit, with typical appliances being 5-50 MW/unit.

Larger applications are typically a combination of multiple single units.

Space requirements
The net space requirements of electric boilers are in the range of 20-40 m^2/unit with a total height of approx. 5-6.5 m. Examples of smaller units can be found as well. Furthermore, there is a space requirement of approx. 50-100 m^2/appliance for heat exchangers, piping etc.

Regulation ability
Electric boilers can participate in up- and downward regulation. Modern electrode boilers have a minimal standby consumption when used as frequency-controlled reserves (down regulation). The standby consumption varies with the type of electric boiler. New electrode boilers of e.g. 12 MW have electricity consumption down to a few kW and no consumption at high voltage. Older types may have a standby consumption of 5-10 %. The above mentioned new generation of electrode boilers operate in such a way that the voltage is kept in the boiler, without applying any power. Using this technology, the only “stand-by consumption” is related to internal pumps and electric boilers can start with close to no standby consumption. Considering the close to none standby demand, many plants chose to keep the boiler operating in standby mode in order to be able to utilize the electrode boilers immediately when necessary.

Alternatively, it is possible to offer regulating power from cold start, hence eliminating the need for a standby consumption. This is made possible ramp up times of approx. 5 minutes in cold start situations, typically being shorter than necessary to participate on e.g. the power balancing market. However, due to the above-mentioned minimal standby consumption, operation on electrode boilers in standby is very common. The load shift from 0-100 % of nominal capacity is approx. 30 seconds. [8] [9]

Advantages/disadvantages

Advantages

Due to its very simple design, the electric boiler is extremely dependable and easy to maintain. The boiler has no built-in complex components, which may impede operation and maintenance. The boiler has quick startup and fast load-response. It requires no fuel feeding systems and no stack.

Disadvantages

As the input energy is electricity, the operating costs are subject to the variation in the electricity prices (market dependent) and the taxes on electricity. Electricity prices thus constitute a major part of the operation costs, without being the only factor to consider when evaluating the economy of operation.

In case electric boilers utilize power from thermal power production, exergetical losses will have to be considered in the evaluation of the total energy balance. Depending on the type of grid connection (full/limited), the availability of the electric boiler may be limited, as explained in the Brief technology description.

Environment

During operation, the electric boiler uses electricity and the environmental impact from operation depends on the origin of the electricity. Apart from the emissions, due to the consumed electricity, electric boilers have no local environmental impact.

Research and development perspectives

The technology is well developed, tested and commercially available. Future development will focus on dynamic use of electric boilers in connection with the power system. The development objectives are thus assessed to be limited to the dynamic application of electric boilers, according to the economic & legislative framework, rather than further development of the electric boiler itself. [8] [9]

Examples of market standard technology

Swedish boiler manufacturer Zander & Ingeström (ZVBA-boiler) [2] and Norwegian boiler manufacturer PARAT (Parat IEH) [3] produce state-of-the-art electrode boilers. Additionally, [7] comprises an overview of installed electric boilers in district heating systems in Denmark, including a map and a list of plants.

Technical aspects of applying electric boilers in district heating

The technical criteria for participating in the ancillary services of the Nordic electricity market vary in terms of the necessary start up times and the duration of activation. Participating with the early applications of electric boilers (built 2006-08) as manual frequency restoration or replacement reserves (mFRR / RR, start-up time: 15 minutes) could happen from a cold-start. Application as frequency containment reserves (FCR, start-up time: 30s) and automatic frequency restoration reserves for regulating power (aFRR, start-up time: 5 minutes) however required the electric boilers to operate in stand-by. From approximately 2010-12, many electrode boilers were modified, making it possible to ramp up from 0 % to 100 % of the nominal capacity within 30 seconds. Thus, the early boilers today have the same technical specifications in terms of start-up times and energy efficiency as the new built.

Most distribution system operators (DSO) choose to offer limited grid access for electric boilers, thus limiting the available electric capacity for the boilers in hours of high load. Having the possibility of full grid access at all times typically results in higher expenses for the grid connection, worsening the economy of the electric boiler project. Depending on the DSO and the grid situation, a minimum load can be negotiated.

Operating electric boilers in the Nordic electricity market

The economic framework of the Nordic electricity market is dynamic in terms of necessary capacities and traded volumes as ancillary services. The variation of bidding players results in further dynamics of the market framework, creating a continuously changing framework for electric boilers to be operated within [1] [4].

The first electric boilers in the district heating systems in Denmark were installed in 2006-2008. The design of the electricity market in this period created a promising framework for electric boilers in terms of availability payments in mainly the manual reserve (ramp-up time 15 minutes). This was followed by potentially high revenues from other reserve markets and the trading of regulating power in general. Together with other motives, this resulted in an increase of the installation of additional capacity to approximately 400 MW by the end of 2012 and approximately 490 MW by the end of 2015. Besides the described ancillary services, the transmission system operator (TSO) has the possibility to activate “special regulating energy” (Danish title: Specialregulering) if the stability of the grid makes this necessary. The use of this option has increased throughout 2014-15, mainly due to high penetration and design of subsidy schemes of wind power in Northern Germany. The activation of Danish electricity consumption proved to be a cost-effective way to integrate surplus wind power, with forced shut-downs of wind turbines being the alternative, cf. the curtailment of wind power regulation in Northern Germany in hours of high load [5].

The techno-economic application of electric boilers in district heating

Based on the above, investments in electric boilers have historically been partially driven by the chance of making a profit at the FCR market. Other arguments for the electric boilers, such as security of supply through the installation of electric boilers as peak and backup capacity are increasing in importance, as the yields from FCR are varying. Furthermore, electrode boilers constitute a promising option for thermal power plants to integrate the electrical output in minimum load operation situations. Thus, the electrical power can be used for heat generation instead of being fed into the grid in hours of negative spot prices.

Since 2012, there has been only one – very large – new application. The installation of 2x40 MW electric boilers at Studstrup CHP plant in Aarhus (2015) and an electrode boiler at Asnæsværket in Kalundborg with a total capacity of 93 MW (2002) are the biggest applications in Denmark yet. Furthermore, a 30 MW electric boiler was installed at a CHP plant of Silkeborg Forsyning.

Figure 3: Overview of large installations in Denmark. The interactive map is available at [7]. A list of applications is available at the same web-site. 45 applications with a total of 490 MW. The largest applications are 80 and 93 MW (2015 and 2002 respectively).

List of suppliers of electric boilers:

- Aktive Energi Anlæg, www.aea.dk
- Tjæreborg Industri, www.tji.dk
- as:scan industries, www.scan-industries.com
- DWC, www.dwcsystems.com

Application of domestic scale electric boilers

In the small-scale range, household applications designed for ultra-low temperature district heating systems may serve as supplementing technology. The purpose is to top up the district heating supply to fulfil the hot tap water demand. This enables low temperature district heating implying reductions in heat losses and efficient utilisation of various low temperature heat sources (applying heat pumps with high COP). Small-scale electric water heaters (household application; approx. 5-30 kW) are subject to ecolabbeling [6]. These units are described in another catalogue on individual heating technologies.

Prediction of performance and costs

Electric boilers are a mature technology. Further development is thus estimated to be limited to reductions in equipment costs, due to an increase in the volume of sales.

The likeliness of district heating companies to invest in electric boilers is dependent on revenues from e.g. the regulating power market and other flexible ways to offer (downward) regulating power as described above. A development potential is the (supposedly increasing) necessity for thermal power plants to operate in minimum load at low or negative electricity prices. As the above factors are subject to uncertainty, minimizing the planning security, no major development of electric boilers is expected. The development potential is assessed to be related to the market shares of electric boilers only, as opposed to further technological development.

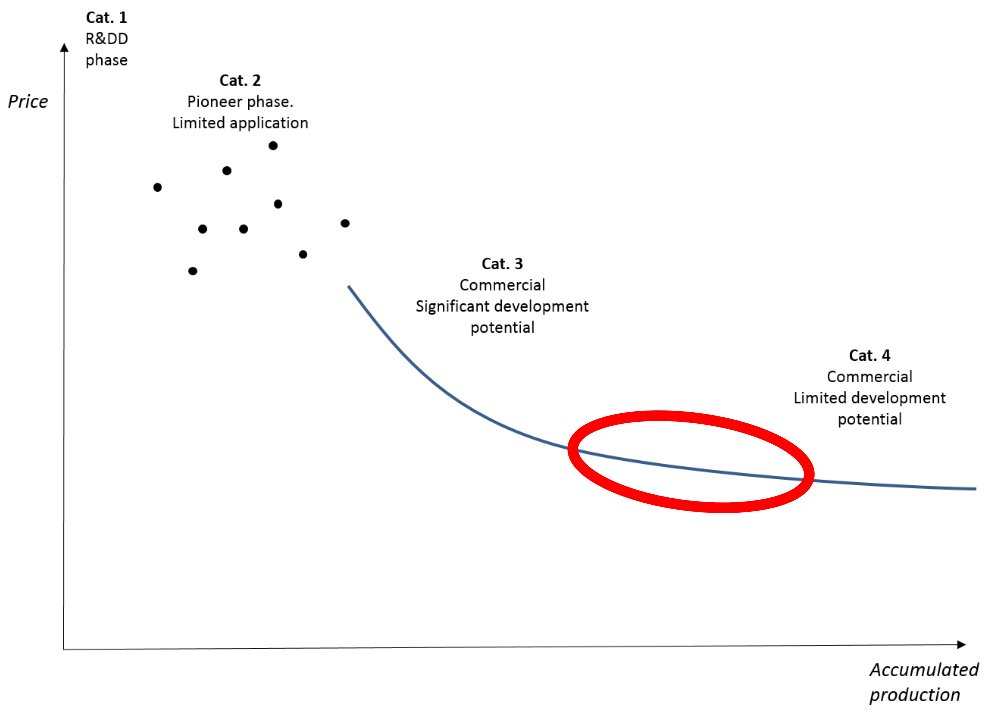


Figure 4: Technological development phases. Correlation between accumulated production volume (MW) and price. Electric boilers are to be placed between category 3 and 4, with the main development potential being related to a possible increased market penetration ("Commercial, limited development potential").

Uncertainty

For electric boilers, the uncertainty is low, because electric boilers are categorized as category 3-4. It is assessed that there will be no major decreases in the equipment costs, as these would imply a strong increase in sales volumes (and vice versa).

Additional remarks

The operating costs of an electric boiler are highly dependent on the costs of electricity, i.e. the market price of electricity and currently applicable taxes and fees. Thus, heat production on electric boilers in e.g. a district heating plant can only compete with other heat production units at low electricity prices (e.g. in periods with high wind power production).

The number of full-load hours (heat) for electric boilers is assumed to be 500 according to the Guideline.

Data sheets

Technology	Electric boilers, 400 or 690 V, 0.06-5 MW; 10 or 15 kV, >10 MW									
Energy/technical data	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref.
					Lower	Upper	Lower	Upper		
Heat generation capacity for one unit (MW)	5				1	25	1	25		
Total efficiency, net (%), name plate	99	99	99	99	99	99	99	99		10
Total efficiency , net (%), annual average	99	99	99	99	99	99	99	99		10
Electricity consumption for pumps etc. (% of heat gen)	0.5	0.5	0.5	0.5	0.1	0.5	0.1	0.5		10
Forced outage (%)	1	1	1	1	0.5	1	0.5	1	E	10
Planned outage (weeks per year)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	E	10
Technical lifetime (years)	20	20	20	20	20	20	20	20		10
Construction time (years)	0.5	0.5	0.5	0.5	0.5	1	0.5	1		10
Regulation ability										
Primary regulation (% per 30 seconds)	100	100	100	100	100	100	100	100		10
Secondary regulation (% per minute)	100	100	100	100	100	100	100	100		10
Minimum load (% of full load)	5									10
Warm start-up time (hours)	0.008									11
Cold start-up time (hours)	0.08									11
Financial data										
Nominal investment (M€ per MW), 400/690 V; 1-5 MW	0.15	0.15	0.14	0.13	0.10	0.25	0.10	0.25	A	10
- of which equipment	0.12	0.12	0.11	0.10	0.08	0.20	0.08	0.20	B	10
- of which installation	0.03	0.03	0.03	0.03	0.02	0.05	0.02	0.05	D	10
Nominal investment (M€ per MW); 10/15 kV; >10 MW	0.07	0.07	0.06	0.06	0.02	0.17	0.02	0.17	A	10
- of which equipment	0.06	0.06	0.05	0.05	0.02	0.14	0.02	0.14	C	10
- of which installation	0.01	0.01	0.01	0.01	0	0.03	0	0.03	D	10
Fixed O&M (€/MW/year)	1100	1070	1020	920	1000	1100	900	1000	A	10
Variable O&M (€/MWh)	0.8	0.9	1.0	1.2	0.5	0.9	0.5	1.3		10
- of which is electricity costs (€/MWh)	0.3	0.3	0.5	0.6	0.1	0.3	0.1	0.6	F	
- of which is other O&M costs (€/MWh)	0.5	0.5	0.5	0.4	0.4	0.5	0.3	0.5	A	10
Technology specific data										
Startup costs (€/MW/startup)	0	0	0	0	0	0	0	0		10

Notes:

E The investment and O&M costs are assessed in relation to an approx. operation in 500 hours/year.

F The installation at low voltage necessitates a transformer substation & expansion of the distribution board. Costs for these are included in the stated equipment costs.

G Electrode boilers at medium-high voltage are directly connected to the distribution grid. Costs for the distribution board are included in the equipment costs.

H The installation costs include costs for electrical integration & grid connection fees.

I The forced outage of electric boilers is very limited and typically well below 1 %. The planned outage is typically limited to 1 day/year.

J The cost of auxiliary electricity consumption is calculated using the following electricity prices in €/MWh: 2015: 63, 2020: 69, 2030: 101, 2050: 117. These prices include production costs and transport tariffs, but not any taxes or subsidies for renewable energy.

References

[36] PlanEnergi, Teknologisk Institut, GEO & Grøn Energi, Review of thermal storage technologies and heat pumps in district heating systems [Danish title: ”Udredning vedrørende varmelagringsteknologier og store varmepumper til brug i fjernvarmesystemet”], 2013

[37] Zander&Ingström, homepage of electrode boiler manufacturer, www.zeta.se/boilers/en

[38] PARAT, homepage of electrode boiler manufacturer, http://parat.no/en/products/industry/parat-ieh-high-voltage-electrode-boiler/

[39] Parbo, H., Purchase of regulating power, special regulation and other power system services [Danish title: ”Indkøb af regulerkraft, specialregulering og øvrige systemydelser”], Presentation at Dansk Fjernvarme, August 31st, 2015

[40] Article (in Danish): Tyskland beder i stigende grad danske vindmøller om at stå stille. Available at: http://www.energinet.dk/DA/El/Nyheder/Sider/Tyskland-beder-i-stigende-grad-danske-vindmoeller-om-at-staa-stille.aspx

[41] Draft commission decision of […] establishing the criteria for the award of the EU Ecolabel for water-based heaters, draft version 5, July 2013. Available at: http://www.ecolabel.dk/~/media/Ecolabel/Files/Hoeringer/Blomstm%C3%A6rkede-tekstiler-madrasser-maling/Waterbased-heaters.ashx

[42] www.smartvarme.dk

[43] BVA Elektrokessel, Personal Communication, 2016

[44] Tjæreborg Industri, Personal Communication, 2016

[45] Tjæreborg Industri, Personal Communication, 2015

[46] Parat, unknown date, Brochure High Voltage Electrode Boiler, available at http://parat.no/media/201154/Electrode-Boiler-web.pdf

42 Waste-to-Energy District Heating Plant (updated datasheet available)

For technical descriptions of the technologies go to previous catalogue. In this catalogue a common qualitative description of the the technology sheets of biomass and waste fired plants (chapter 08, 09, 42 and 43) are presented in chapter 99 in this publication.

The specific chapter for *Waste-to-Energy District Heating Plant* is under review. The old version (2012/2015) is found in the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

Data sheets: Waste, DH only

Technology	**Waste to Energy, DH only, 35 MW feed**									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Heat generation capacity for one unit (MW)	36,6	36,6	36,7	36,9	36,3	37,5	36,3	37,7	A, B	
Incineration capacity (Fuel input) (tonnes/h)	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	A, B	
Total heat efficiency, net (%), ref. LHV, name plate	104,7	104,7	105,0	105,5	104	107	104	108	A, B, C	
Total heat efficiency , net (%), ref. LHV, annual average	104,7	104,7	105,0	105,5	104	107	104	108	A, B, C	
Additional heat potential with heat pumps (% of thermal input)	4,1	4,1	4,0	3,7	2	5	2	5	A, B, D	
Auxiliary electricity consumption (% of heat gen)	2,6	2,6	2,6	2,5	2,0	2,7	1,6	2,6	A, B, C	
Forced outage (%)	1	1	1	1	1	1	1	1		1
Planned outage (weeks per year)	3,0	2,9	2,6	2,1	2,4	3,3	1,6	2,6	E	1
Technical lifetime (years)	25	25	25	25	20	35	20	35		1
Construction time (years)	2	2	2	2	1,5	2,5	1,5	2,5		1
Space requirement (1000 m2/MWth heat output)	0,55	0,55	0,54	0,54	0,46	0,63	0,41	0,68		1
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA	F	
Secondary regulation (% per minute)	1	1	1	1	1	1	1	1	F, G	
Minimum load (% of full load)	70	70	70	70	70	70	70	70	F, G	
Warm start-up time (hours)	8	8	8	8	8	8	8	8	F, G	
Cold start-up time (hours)	12	12	12	12	12	12	12	12	F, G	
Environment										
SO_2 (degree of desulphuring, %)	99,8	99,8	99,8	99,8	99,0	99,9	99,5	99,9	H	1
NO_X (g per GJ fuel)	90	67	56	22	11	84	5	56	I	2;3
CH4 (g per GJ fuel)	0,3	0,1	0,1	0,1	0	0,1	0	0,1		2
N2O (g per GJ fuel)	1,2	1	1	1	1	3	0	1	J	2
Particles (g per GJ fuel)	0,3	0,3	0,3	0,3	0,1	2	0,1	1	J	2
Financial data										

Nominal investment (M€/MWth - heat output)	1,80	1,75	1,66	1,55	1,53	2,12	1,24	2,13	P	
- of which equipment	1,03	1,01	0,96	0,92	0,88	1,24	0,71	1,24	P	
- of which installation	0,77	0,75	0,71	0,64	0,65	0,88	0,53	0,88	P	
Fixed O&M (€/MWth/year), heat output	81.321	78.600	73.334	65.253	67.980	90.067	50.650	82.474	P	
Variable O&M (€/MWh) heat output	5,5	5,5	5,5	5,5	4,7	6,3	4,1	6,8	P	
Technology specific data										
Flue gas condensation	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	N	
Combustion air humidification	No	No	No	No	No	Yes	No	Yes	N	
Nominal investment (M€/MW fuel input)	1,88	1,84	1,75	1,64	1,60	2,22	1,31	2,24	N	1
- of which equipment	1,08	1,05	1,00	0,97	0,92	1,30	0,75	1,31	N	1
- of which installation	0,80	0,78	0,74	0,67	0,68	0,92	0,56	0,93	M	1
Fixed O&M (€/MW input/year)	85.154	82.305	76.976	68.824	70.536	96.611	52.554	88.770	L	1
Variable O&M (€/MWh input)	7,4	7,6	8,4	8,7	6,2	8,5	6,1	10,3		
- of which is electricity costs (€/MWh)	1,6	1,8	2,6	2,9	1,3	1,9	1,8	3,1	C	
- of which is other O&M costs (€/MWh)	5,8	5,8	5,8	5,8	4,9	6,6	4,3	7,2	K	1
Nominal investment (€/(tonne/year))	693	676	643	604	589	819	482	826	N	1
Fixed O&M (€/tonne)	31	30	28	25	26	36	19	33	L	1;4
Variable O&M (€/tonne)	17	17	17	17	14	20	13	21	K	1;4

Notes:

A Assumed lower heating value 10.6 MJ/kg, waste input 11.9 tph = tonnes per hour (incineration capacity), corresponding to thermal input of 35 MW. Efficiencies refer to lower heating value.

B With flue gas condensation (condensation through heat exchange with DH-water, only), DH return temperature 40°C and flow 80°C

C The stated total efficiency does NOT consider auxiliary electricity consumption. It describes the total net amount of heat produced at the plant. This is contrary to CHP where the auxiliary electricity is subtracted from the production to yield the net electricity efficiency. Instead the cost of auxiliary electricity consumption is included in variable O&M and is calculated using the following electricity prices in €/MWh: 2015: 63, 2020: 69, 2030: 101, 2050: 117. These prices include production costs and transport tariffs, but not any taxes or subsidies for renewable energy.

D Additional heat potential for heat pump is the flue gas condensation potential remaining after the direct condensation stage (condensation by heat exchange with DH-water)

E Focus on availability and ambitions of 2 years' continuous operation is expected to gradually reduce planned outage.

F Regulation and start-up refer to electricity generation controlled by the turbine operation.The WtE facility would usually be operating at 100% thermal input, and the electricity output is controlled to the desired level by use of turbine by-pass, by which excess steam is used to produce DH-energy. Warm start-up time refers to 2 days down-time of the turbine.

G The combustion process and boiler may be regulated approx. 1% per minute considering extensive use of inconell (in stead of refractory, which may limit rate of change to 0.5% per minute). Minimum load is typically 70% of thermal input under which limit it may be difficult to comply with the requirement of min. 2 sec residence time of the flue gas at min. 850 °C after the last air injection. Below this limit it may also be a challenge to ensure sufficient superheating of the steam. Warm start-up of the combustion process is typically 8 hours and cold start-up is 8 hours.

H Assumed low SO2-emission 1 g/GJ in 2015 considering the use of flue gas condensation by wet scrubbing down-stream the flue gas treatment system. Sulphur content in fuel 270 g/GJ

I Increased focus on NOx reduction is expected in the future, requiring use of SNCR technology to its utmost potential by 2030 (at 60 g/GJ) and use of the more effective catalytic SCR-technology by 2050. The SCR-technology entails additional investment.

J N2O is expected to be related primarily to the use of SNCR. This is why little N2O is expected when the SCR-deNOx technology is used (indicated by verly low NOx-level).

K Variable O&M cost includes consumables (for FGT etc.), disposal of residues, small share of staff-cost and maintenance cost. Electricity consumption is not included, and revenues from sale of electricity and heat are not included. Taxes are not included.

L Fixed O&M include amongst other things the major part of staffing and maintenance, analyses, research and development, accounting, insurances, fees, memberships, office. Not included are finance cost, depreciation and amortisation.

M Installation includes civils works (including waste bunker) and project cost considering LOT-based tendering

N Assuming LOT-based tendering of electromechanic equipment

P Reference to heat output because of the lack of electricity production

References

1 Rambøll present work, range of WtE-projects

2 Emission factors of 2006: 102 g/GJ NOx, <8,3 g/GJ for SO2, <0,34 g/GJ for CH4, 1,2 g/GJ for N2O, cf.

Nielsen, M., Nielsen, O.-K. & Thomsen, M. 2010: Emissions from decentralised CHP plants 2007 - Energinet.dk Environmental project no. 07/1882. Project report 5 – Emission factors and emission inventory for decentralised CHP production. National Environmental Research Institute, Aarhus University. 113 pp. – NERI Technical report No. 786.

http://www.dmu.dk/Pub/FR786.pdf.

3 Environmental permit of recently constructed WtE-facility includes NOx limit value of 180 mg/Nm³ =100 g/GJ. Operation is expected well below limit value. Cf. Miljøstyrelsen, "Tillæg til miljøgodkendelse, Ny ovnlinje 5 på Nordforbrænding, Juni 2013," http://mst.dk/media/mst/Attachments/Tillgtilmiljgodkendelseovn5Juni2013.pdf

4 To scenarier for tilpasning af affaldsforbrændingskapaciteten i Danmark. EA Energianalyse 2014.

43 District Heating Boiler, Biomass Fired (updated datasheet available)

For technical descriptions of the technologies go to previous catalogue. In this catalogue a common qualitative description of the the technology sheets of biomass and waste fired plants (chapter 08, 09, 42 and 43) are presented in chapter 99 in this publication.

The specific chapter for *District Heating Boiler, Biomass Fired plants* is under review. The old version (2012/2015) is found in the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

Data sheets Wood Chips, DH only

Technology	**Wood Chips, DH only, 6 MW feed**									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Heat generation capacity for one unit (MW)	6,9	6,9	6,9	6,9	5,3	6,9	5,3	6,9	A	1
Total efficiency, net (%), name plate	114,9	114,9	114,9	114,9	89	115	89	115	B,C	1
Total efficiency , net (%), annual average	114,9	114,9	114,9	114,9	89	115	89	115	B,C	1

Additional heat potential with heat pumps (% of thermal input)	2,0	2,0	2,0	2,0	2	28	2	28	D	1
Auxiliary electricity consumption (% of heat gen)	2,3	2,3	2,3	2,3	2,2	2,5	1,8	2,5	C,K	
Forced outage (%)	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0		
Planned outage (weeks per year)	2,0	2,0	2,0	2,0	1,7	2,3	1,5	2,5		
Technical lifetime (years)	25,0	25,0	25,0	25,0	20,0	35,0	20,0	35,0		1
Construction time (years)	1,0	1,0	1,0	1,0	0,5	1,5	0,5	1,5		1
Space requirement (1000 m2/MWth heat output)	0,2	0,2	0,2	0,2	0,2	0,3	0,2	0,3		
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA		
Secondary regulation (% per minute)	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	E	1
Minimum load (% of full load)	20	20	20	20	20	20	20	20	E	1
Warm start-up time (hours)	0,3	0,3	0,3	0,3	0,3	0,3	0,3	0,3	H	1
Cold start-up time (hours)	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5		1
Environment										
SO_2 (degree of desulphuring, %)	98,0	98,0	98,0	98,0	89,9	99,0	98,0	99,0	G	1
NO_X (g per GJ fuel)	90	63	49	41	41	81	28	41	I	
CH4 (g per GJ fuel)	16	11	8	4	4	16	2	16	I	
N2O (g per GJ fuel)	4	3	3	1	1	4	1	4	I	
Particles (g per GJ fuel)	2,0	0,3	0,3	0,3	0,1	2,0	0,1	1,0	I	
Financial data										
Nominal investment (M€/MWth - heat output)	0,70	0,68	0,65	0,59	0,60	0,81	0,49	0,81	F, L	
- of which equipment	0,41	0,40	0,38	0,34	0,35	0,47	0,28	0,47	F, L	
- of which installation	0,30	0,29	0,27	0,25	0,25	0,34	0,21	0,34	F, L	
Fixed O&M (€/MWth/year), heat output	32.774	32.242	31.217	29.316	35.751	37.287	29.296	37.640		
Variable O&M (€/MWh) heat output	1,0	1,0	1,0	1,0	0,8	1,1	0,7	1,2		
Technology specific data										
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes	J, L	
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes	J, L	
Nominal investment (M€/MW fuel input)	0,81	0,79	0,75	0,68	0,69	0,93	0,56	0,94	J, L	1
- of which equipment	0,47	0,46	0,43	0,39	0,40	0,54	0,32	0,54	L	
- of which installation	0,34	0,33	0,32	0,29	0,29	0,39	0,24	0,39	L	
Fixed O&M (€/MW input/year)	37.667	37.055	35.876	33.692	31.728	42.926	25.999	43.332		

Variable O&M (€/MWh input)	2,5	2,7	3,4	3,7	2,4	3,0	2,9	4,3		
- of which is electricity costs (€/MWh)	1,4	1,6	2,3	2,6	1,5	1,7	2,1	2,9	C	
- of which is other O&M costs (€/MWh)	1,1	1,1	1,1	1,1	0,9	1,3	0,8	1,4		
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,020	0,020	0,019	0,017	0,017	0,023	0,014	0,023	L	

Notes:

A The plant is directly producing hot water for District Heating by burning fuel on a grate.

B Boilers up to 20 MW fuel input for hot water production are more or less standardized products with a high degree of fuel flexibility (type of biomass, humidity etc.)

C Efficiencies refer to lower heating value. The stated total efficiency does NOT consider auxiliary electricity consumption. It describes the total net amount of heat produced at the plant. This is contrary to CHP where the auxiliary electricity is subtracted from the production to yield the net electricity efficiency. Instead the cost of auxiliary electricity consumption is included in variable O&M and is calculated using the following electricity prices in €/MWh: 2015: 63, 2020: 69, 2030: 101, 2050: 117. These prices include production costs and transport tariffs, but not any taxes or subsidies for renewable energy.

D There are plants of this type with up to 108 % efficiency using flue gas condensation with moist wood chips and close to 115 % efficiency with both flue gas condensation and absorption heat pumps activated. The colder the return temperature of the district heating, the higher the total efficiency at direct condensation. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.

E Load control of the heat production is important and units of this size can make rapid load variations. Similarly, the minimum load is quite low

F Reference to heat output because of the lack of electricity production

G assuming content of sulphur in fuel of 20 g/GJ

H Warm start is starting with a glowing fuel layer on the grate.

I Estimated from: Nielsen, M., Nielsen, O.-K., Plejdrup, M. & Hjelgaard, K., 2010: Danish Emission Inventories for Stationary Combustion Plants. Inventories until 2008. National Environmental Research Institute, Aarhus University, Denmark. 236 pp. – NERI Technical Report No. 795. http://www.dmu.dk/Pub/FR795.pdf.

J The nominal investment is in the range 0.6 to 1.1 M€/Mwth

K Result of model calculation, there are reports of DH plants operating at lower power consumption, down to 1% of heat generation.

L Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies.

Data sheets Wood Pellets, DH only

Technology	**Wood Pellets, DH only, 6 MW feed**									
	2015	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data					**Lower**	**Upper**	**Lower**	**Upper**		
Heat generation capacity for one unit (MW)	6,0	6,0	6,0	6,0	5,4	6,0	5,4	6,0	A	1
Total efficiency, net (%), name plate	100,1	100,1	100,1	100,1	90	100	90	100	B,C	1
Total efficiency , net (%), annual average	100,1	100,1	100,1	100,1	90	100	90	100	B,C	1

Additional heat potential with heat pumps (% of thermal input)	1,7	1,7	1,7	1,7	2	12	2	12	D	1
Auxiliary electricity consumption (% of heat gen)	2,1	2,1	2,1	2,1	1,8	2,3	1,4	2,3	C,K	
Forced outage (%)	3,0	3,0	3,0	3,0	3,0	3,0	3,0	3,0		
Planned outage (weeks per year)	3,0	3,0	3,0	3,0	2,6	3,5	2,3	3,8		
Technical lifetime (years)	25,0	25,0	25,0	25,0	20,0	35,0	20,0	35,0		1
Construction time (years)	1,0	1,0	1,0	1,0	0,5	1,5	0,5	1,5		1
Space requirement (1000 m2/MWth heat output)	0,2	0,2	0,2	0,2	0,1	0,2	0,1	0,2		
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA		
Secondary regulation (% per minute)	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	E	1
Minimum load (% of full load)	40,0	40,0	40,0	40,0	40,0	40,0	40,0	40,0	E	1
Warm start-up time (hours)	0,3	0,3	0,3	0,3	0,3	0,3	0,3	0,3	H	1
Cold start-up time (hours)	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5		1
Environment										
SO_2 (degree of desulphuring, %)	98,3	98,3	98,3	98,3	91,3	99,1	98,3	99,1	G	1
NO_X (g per GJ fuel)	90	54	42	35	35	70	25	35	G	1
CH4 (g per GJ fuel)	0	0	0	0	0	0	0	0	G	1
N2O (g per GJ fuel)	1	1	1	1	1	3	0	1	G	1
Particles (g per GJ fuel)	2,0	0,3	0,3	0,3	0,1	2,0	0,1	1,0	G	1
Financial data										
Nominal investment (M€/MWth - heat output)	0,74	0,72	0,69	0,67	0,63	0,90	0,57	0,91	F, L	
- of which equipment	0,45	0,44	0,42	0,43	0,38	0,57	0,36	0,57	F, L	
- of which installation	0,29	0,28	0,27	0,24	0,25	0,33	0,20	0,34	F, L	
Fixed O&M (€/MWth/year), heat output	33.952	33.023	31.282	29.229	31.658	39.218	25.601	37.399	F	
Variable O&M (€/MWh) heat output	0,5	0,5	0,5	0,5	0,4	0,6	0,4	0,6	F	
Technology specific data										
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes	J	
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes	J	
Nominal investment (M€/MW fuel input)	0,74	0,72	0,69	0,67	0,63	0,90	0,57	0,91	J, L	1
- of which equipment	0,45	0,44	0,42	0,43	0,38	0,57	0,36	0,57	L	
- of which installation	0,29	0,28	0,27	0,24	0,25	0,34	0,20	0,34	L	
Fixed O&M (€/MW input/year)	34.000	33.070	31.327	29.271	28.334	39.341	22.913	37.516		
Variable O&M (€/MWh input)	1,8	1,9	2,6	2,9	1,6	2,2	2,1	3,3		
- of which is electricity costs (€/MWh)	1,3	1,4	2,1	2,4	1,2	1,6	1,7	2,7	C	
- of which is other O&M costs (€/MWh)	0,5	0,5	0,5	0,5	0,4	0,6	0,4	0,6		
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,004	0,004	0,004	0,003	0,003	0,005	0,003	0,005	L	

Notes:

A The plant is directly producing hot water for District Heating by burning fuel on a grate.

B Boilers up to 20 MW fuel input for hot water production are more or less standardized products with a high degree of fuel flexibility (type of biomass, humidity etc.)

C The stated total efficiency does NOT consider auxiliary electricity consumption. It describes the total net amount of heat produced at the plant. This is contrary to CHP where the auxiliary electricity is subtracted from the production to yield the net electricity efficiency. Instead the cost of auxiliary electricity consumption is included in variable O&M and is calculated using the following electricity prices in €/MWh: 2015: 63, 2020: 69, 2030: 101, 2050: 117. These prices include production costs and transport tariffs, but not any taxes or subsidies for renewable energy.

D There are plants of this type with up to 108 % efficiency using flue gas condensation with moist wood chips and close to 115 % efficiency with both flue gas condensation and absorption heat pumps activated. The colder the return temperature of the district heating, the higher the total efficiency at direct condensation. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.

E Load control of the heat production is important and units of this size can make rapid load variations. Similarly, the minimum load is quite low

F Reference to heat output because of the lack of electricity production

G Emissions shall comply with Danish EPA guideline, Luftvejledningen.
It is anticipated that for the smaller units the supplier has an SNCR solutiuon to reduce NOx emissions sufficiently.

I Warm start is starting with a glowing fuel layer on the grate.

J The nominal investment is in the range 0.6 to 1.1 M€/Mwth

K Result of model calculation, there are reports of DH plants operating at lower power consumption

L Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things.
The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies.

Data sheets Straw, DH only

Technology	Small Straw, DH only, 6 MW feed									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Heat generation capacity for one unit (MW)	6,1	6,1	6,1	6,1	5,4	6,1	5,4	6,1	A	1
Total efficiency, net (%), name plate	102,1	102,1	102,1	102,1	89	102	89	102	B,C	1
Total efficiency , net (%), annual average	102,1	102,1	102,1	3,0	89	102	89	102	B,C	1
Additional heat potential with heat pumps (% of thermal input)	1,7	1,7	1,7	1,7	2	14	2	14	D	1
Auxiliary electricity consumption (% of heat gen)	2,1	2,1	2,1	2,1	1,9	2,3	1,5	2,3	C,J	
Forced outage (%)	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0		
Planned outage (weeks per year)	4,0	4,0	4,0	4,0	3,4	4,6	3,0	5,0		

Technical lifetime (years)	25,0	25,0	25,0	25,0	20,0	35,0	20,0	35,0		1
Construction time (years)	1,0	1,0	1,0	1,0	0,5	1,5	0,5	1,5		1
Space requirement (1000 m2/MWe)	0,2	0,2	0,2	0,2	0,2	0,3	0,2	0,3		
Primary regulation (% per 30 seconds)	NA	NA	NA	NA	NA	NA	NA	NA		
Secondary regulation (% per minute)	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	E	1
Minimum load (% of full load)	50,0	50,0	50,0	50,0	50,0	50,0	50,0	50,0	E	1
Warm start-up time (hours)	0,3	0,3	0,3	0,3	0,3	0,3	0,3	0,3	H	1
Cold start-up time (hours)	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5		1
Environment										
SO_2 (degree of desulphuring, %)	95,5	96,4	99,1	99,8	90,9	99,8	95,5	99,9	G	1
NO_X (g per GJ fuel)	90	72	73	73	36	90	18	73	G	1
CH4 (g per GJ fuel)	16	11	8	4	4	16	2	16	G	1
N2O (g per GJ fuel)	4	3	2	1	1	4	1	4	G	1
Particles (g per GJ fuel)	2,0	0,3	0,3	0,3	0,1	2,0	0,1	1,0	G	1
Financial data										
Nominal investment (M€/MWth - heat output)	0,91	0,89	0,84	0,76	0,77	1,09	0,63	1,10	F,K	
- of which equipment	0,44	0,43	0,41	0,37	0,37	0,56	0,31	0,56	F,K	
- of which installation	0,47	0,46	0,43	0,39	0,40	0,54	0,32	0,54	F,K	
Fixed O&M (€/MWth/year), heat output	52.892	51.328	48.412	43.335	50.191	60.208	37.997	56.215	F	
Variable O&M (€/MWh) heat output	0,6	0,6	0,6	0,6	0,5	0,7	0,4	0,7	F	
Technology specific data										
Flue gas condensation	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Combustion air humidification	Yes	Yes	Yes	Yes	No	Yes	No	Yes		
Nominal investment (M€/MW fuel input)	0,93	0,90	0,86	0,78	0,79	1,12	0,64	1,12	I,K	1
- of which equipment	0,45	0,44	0,42	0,38	0,38	0,57	0,31	0,57	K	
- of which installation	0,48	0,46	0,44	0,40	0,41	0,55	0,33	0,55	K	
Fixed O&M (€/MW input/year)	54.000	52.403	49.426	44.243	44.767	61.575	33.890	57.491		

Variable O&M (€/MWh input)	1,9	2,1	2,7	3,1	1,8	2,3	2,2	3,5		
- of which is electricity costs (€/MWh)	1,3	1,5	2,1	2,5	1,3	1,6	1,7	2,7	C	
- of which is other O&M costs (€/MWh)	0,6	0,6	0,6	0,6	0,5	0,7	0,5	0,8		
Fuel storage specific cost in excess of 2 days (M€/MW_input/storage day)	0,080	0,078	0,074	0,067	0,068	0,092	0,056	0,093	K	

Notes:

A The plant is directly producing hot water for District Heating by burning fuel on a grate.

B Boilers up to 20 MW fuel input for hot water production are more or less standardized products with a high degree of fuel flexibility (type of biomass, humidity etc.)

C The stated total efficiency does NOT consider auxiliary electricity consumption. It describes the total net amount of heat produced at the plant. This is contrary to CHP where the auxiliary electricity is subtracted from the production to yield the net electricity efficiency. Instead the cost of auxiliary electricity consumption is included in variable O&M and is calculated using the following electricity prices in €/MWh: 2015: 63, 2020: 69, 2030: 101, 2050: 117. These prices include production costs and transport tariffs, but not any taxes or subsidies for renewable energy.

D There are plants of this type with up to 108 % efficiency using flue gas condensation with moist wood chips and close to 115 % efficiency with both flue gas condensation and absorption heat pumps activated. The colder the return temperature of the district heating, the higher the total efficiency at direct condensation. Direct condensation and combustion air humidification are included in all cases except in lower range of 2020 and 2050.

E Load control of the heat production is important and units of this size can make rapid load variations. Similarly, the minimum load is quite low

F Reference to heat output because of the lack of electricity production

G Emissions shall comply with Danish EPA guideline, Luftvejledningen. It is anticipated that for the smaller units the supplier has an SNCR solutiuon to reduce NOx emissions sufficiently.

I Warm start is starting with a glowing fuel layer on the grate.

J The nominal investment is in the range 0.6 to 1.1 M€/Mwth

K Result of model calculation, there are reports of DH plants operating at lower power consumption

L Note that investments include only two days fuel storage, and more may be optimal, depending on fuel supply opportunities and heat supply obligations, amongst other things. The additional investment is listed in the bottom row.

References

1 Rambøll Danmark, internal evaluation based on either existing projects, supplier offers, or pre-project studies.

44 District Heating Boiler, Gas Fired

Contact information:

Danish Energy Agency: Rikke Næraa, rin@ens.dk

Energinet.dk: Rune Grandal, rdg@energinet.dk

Publication date
August 2016

Amendments after publication date

Date	Ref.	Description
January 2018	44 gas fired DH boiler	Updated prices for auxiliary electricity consumption in data sheet

Qualitative description

Brief technology description
The fuel is burnt in the furnace section. Heat from the flame is transmitted via radiation (and convection) to the inner walls of the boiler and from there to the water to be heated. After the combustion part, the hot flue gasses are led through the convection parts of the boiler and heat is transmitted to the water to be heated.

Shell and flue gas tube type boilers are the most commonly used type of boilers at Danish district heating plants.

The boiler may be fitted with an external heat exchanger (economizer) to utilise any remaining heat (including latent heat) in flue gasses.

Boilers for district heating have been used for decades. Today, many gas fired district heating boilers are used for peak-load or backup capacity. During periods with low electricity prices, gas fired district heating boilers have accounted for a relatively large part of the district heating production as it has been less feasible to operate the engines at CHP plants.

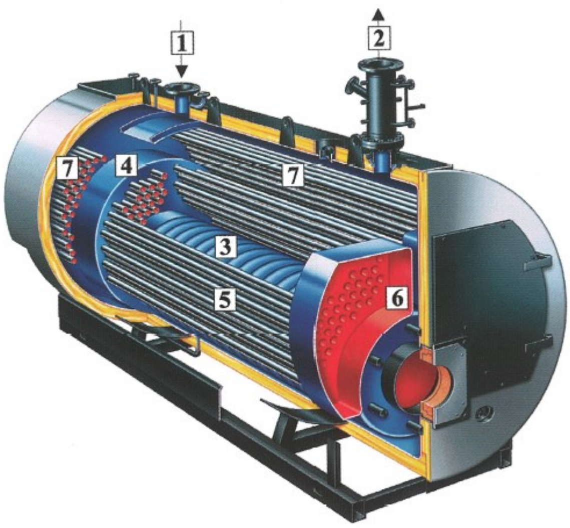


Figure 1 Typical flue gas tube boiler for the power range 1- 20 MW. Combustion takes place in the firetube (3). Flue gasses then passes inside a number of flue gas tubes ((5) & (7)) transmitting further heat to the boiler water around these. The water connections (forward/return) are on the top ((2) & (1)) [6].

Input
Natural gas or biogas.

Output
District heat.

Typical capacities
0.5-20 MJ/s.

Regulation ability and other power system services
Gas fired boilers has a wide turn-up/turn-down ratio. The load can typically be adjusted within 15-100% load. If in operation, this can be done within a few minutes if needed.

If not heated, start-up of cold boilers often takes some 30 minutes.

Advantages/disadvantages
Advantages

Gas fired boilers are a proven and well-known technology. They can be supplied over a wide range of output capacities. Load response is good.

The boilers may also be used for heat extraction at medium- or high-temperature from waste process air.

Heat pumps, either electrical or absorption, may be added to utilize flue gas heat, thereby increasing the efficiency of the heat pump.

Disadvantages

When gas boilers are being fuelled with diesel or biogas, possibly in combination with natural gas, additional sulphur cleaning may be needed.

Environment
Sulphur, NOx and methane emissions when burning natural gas are low compared to biomass or waste fired boilers.

If condensing operation is used, the condensate must be treated to comply with local wastewater standards and regulations before being led to sewage systems. Such treatment often includes pH adjustment.

Research and development perspectives
Multi-fuel operation has been made possible (gas/oil) if supplied with burners for such operation. Biogas is also widely used in same type of boilers. Some boilers can be fitted with special burners for wood dust (e.g. from ground wood pellets) thus enabling conversion to biomass.

Examples of market standard technology
If operated with low return water temperatures (30-35 °C), a district heating boiler with economizer can achieve a fuel efficiency up to approx. 106-107% (lower heating value (LHV) reference).

Prediction of performance and costs

Boiler technology, including gas fired boilers, is a commercial technology with large deployment on both national and international scale. Gas boilers are a commercial technology with a moderate need for R&D, making it a category 4 technology.

Development of the burner technology or post treatment of flue gas may lead to lower emission levels.

Uncertainty

Uncertainty stated in the tables both covers differences between various products and differences related to the power span covered in the actual table.

A span for upper and lower product values is given for the year 2020 situation. No sources are available for the 2050 situation. Hence the values have been estimated by the authors.

No reliable sources are present for the uncertainty of the 2050 numbers listed. However as a deployed, mature and highly fuel-efficient technology, there is relative little uncertainty in performance numbers given.

Additional remarks

Power production units have been developed to be installed in connection with gas fired boilers. The flue gas from power production units can be used as preheated combustion air for the boiler burner.

Data sheets

Technology	44 District heating boiler, natural gas fired									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Heat generation capacity for one unit (MJ/s)	0.5 -10									
Total efficiency, net (%), nominel load	105	105	106	106	95	107	96	108	A	1, 2, 3
Total efficiency , net (%), annual average	103	103	104	104	93	105	94	106	B	1, 3
Electricity consumption for pumps etc. (% of heat gen)	0,15	0,14	0,12	0,1	0,13	0,2	0,08	0,15	L	1
Forced outage (%)	1	1	1	1	0,08	2	0,08	2		3
Planned outage (weeks per year)	0,4	0,4	0,4	0,4	0,3	0,6	0,3	0,6	F	3
Technical lifetime (years)	25	25	25	25	25	>25	25	>25	K	3
Construction time (years)	0,5	0,5	0,5	0,5	0,2	0,7	0,2	0,7	F	9
Space requirement (1000m2 per MJ/s)	0,005	0,005	0,005	0,005	0,003	0,01	0,003	0,01	E	2
Plant Dynamic Capabilities										
Primary regulation (% per 30 seconds)	-	-	-	-	-	-	-	-	C	
Secondary regulation (% per minute)	-	-	-	-	-	-	-	-	C	
Minimum load (% of full load)	15	15	15	15	10	20	10	20		9
Warm start-up time (hours)	0,1	0,1	0,1	0,1	0,08	0,15	0,08	0,15	D	9
Cold start-up time (hours)	0,4	0,4	0,4	0,4	0,3	0,5	0,3	0,5	D	9
Environment										
SO_2 (g per GJ fuel)	0,3	0,3	0,3	0,3	0	0,3	0	0,3	H	1
NO_X (g per GJ fuel)	10	9	7	6	8	60	5	30		1, 2
CH4 (g per GJ fuel)	3	3	2	2	2	6	2	6		1, 2
N2O (g per GJ fuel)	1	1	1	1	NA	NA	NA	NA	I	7
Financial data										
Nominal investment (M€ per MJ/s)	0,06	0,06	0,05	0,05	0,035	0,25	0,035	0,25	J	2, 3
- of which equipment	0,04	0,04	0,03	0,03	0,025	0,15	0,025	0,15		2, 3
- of which installation	0,02	0,02	0,02	0,02	0,01	0,1	0,01	0,1		2, 3
Fixed O&M (€/MJ/s/year)	2000	1950	1900	1700	1000	2500	1000	2500	F	
Variable O&M (€/MWh)	1,1	1,1	1,0	1,0	0,6	2,1	0,6	2,2		
- of which is electricity costs (€/MWh)	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,2	L	
- of which is other O&M costs (€/MWh)	1,0	1,0	0,9	0,9	0,5	2,0	0,5	2,0		8, 9

Notes:

A Includes a condensing economizer, without economizer the efficiency will be up to some 93-97 %, LHV reference

B Includes a condensing economizer, without economizer the efficiency will be up to some 92-95 %, LHV reference

C Not Relevant for heat-only technologies

D Boilers with low water content (e.g. watertube instaed of shell tube 3-5 pass boilers) are used start up time from cold is shorter

E Boilers in the low power range approx. 0.010 and boilersin the higher power range 0.003

F DGC Estimate

G Ultra Low NOx burners can reach a level of 5 g/GJ

H Fuel dependent , not tecchnology dependent

I No data available

J The average numbers are for a 2- 3 MW boiler installation

K Technical lifetime often exceeds 25 years

L The cost of auxiliary electricity consumption is calculated using the following electricity prices in €/MWh: 2015: 63, 2020: 69, 2030: 101, 2050: 117. These prices include production costs and transport tariffs, but not any taxes or subsidies for renewable energy.

References

[1] DGC Statistics, Efficiency and Emission test reports from district heating plants, up to and including 2014

[2] Burner and boiler manufacturer's information 2015

[3] Danish District Heating Association, information given to the 2012 survey for the report

[4] Inputs given by Trade Organisation and boiler installation Company

[5] Industriell Energigasteknik, Gas Akademin, SGC 2011

[6] Industriell Energigasteknik, Gas Akademin, SGC 2004/Viessmann

[7] National Environmental Research Institute, Denmark 2009

[8] Elsam/Elkraft update, Teknologidata for el- og varmeproduktionsanlæg, 1997

[9] DGC calculations, estimates

45 Geothermal District Heating (go to previous catalogue)

This chapter is under review.
Until then please look at the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

46 Solar District Heating (go to previous catalogue)

This chapter is under review.
Until then please look at the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

50 Pumped Hydro Storage (go to previous catalogue)

There are no plans to update this chapter.
For now please look at the previous catalogue at http://www.ens.dk/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger

99 Introduction, Biomass and Waste section

Qualitative description

Contact information

- Danish Energy Agency: Andreas Moltesen/Rikke Næraa
- Author: Rambøll: Claus Hindsgaul, Tore Hulgaard
- Reviewer: Niels Houbak

Edition: 2, date 2017.12.07

1. Common technology description

The qualitative description the technology sheets of biomass and waste fired plants are presented with a common technology description.

Biomass and waste sections plants comprise combined heat and power (CHP) and Heat only facilities fired with biomass or waste, the latter named Waste-to-Energy (WtE) facility.

The main systems are presented in Figure 1 Main systems of a CHP (or Heat only) facility, example WtE CHP facility, illustrated by a WtE CHP facility. The main systems are described in more detail below.

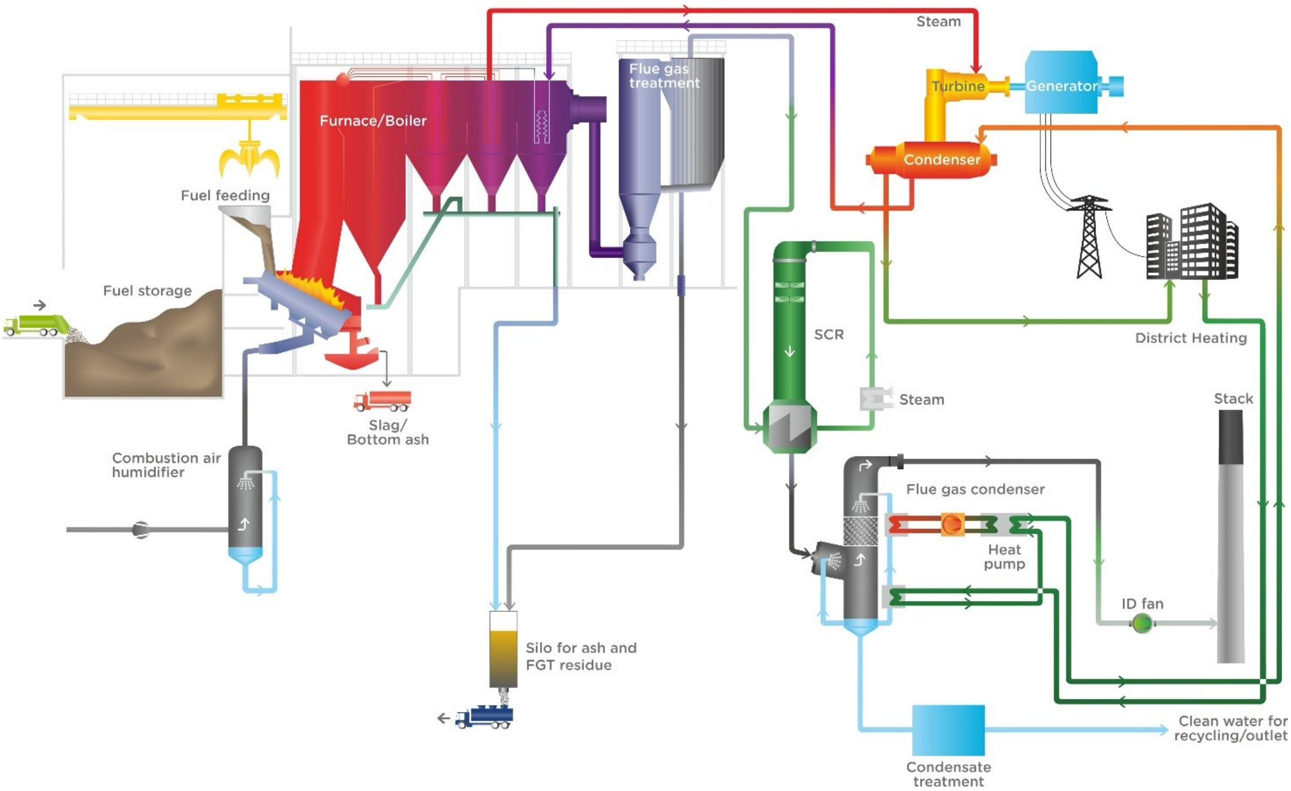


Figure 1 Main systems of a CHP (or Heat only) facility, example WtE CHP facility

The main systems of a biomass or waste fired CHP plant are:

- Fuel reception and storage area,
- Furnace or firing system including fuel feeding
- Steam boiler
- Steam turbine and generator,
- Flue gas treatment (FGT) system potentially including a SCR-system for NOx reduction
- Systems for handling of combustion and flue gas treatment residues
- Optional flue gas condensation system
- Optional combustion air humidification system

In case of heat only plant, the steam boiler is replaced with a hot water boiler, and no turbine/generator set is included. Other main systems are in principle the same as for the CHP-plants.

1.1 Fuels

The considered biomass types are wood chips, wood pellets and straw. Other types of biomass may be relevant as energy source, e.g. other forest residues, sawdust and nut shells.

WtE facilities receive non-recyclable municipal solid waste (MSW), commercial waste and certain fractions of industrial waste and construction & demolition waste. It may also include refuse derived fuel (RDF), for instance imported from the United Kingdom. Certain types of hazardous waste may be included, but dedicated hazardous waste plants are not covered here. More on fuel follows below, section 0.

1.2 Fuel reception and storage

The fuel is received by lorry or boat, and storage is usually available on site for a minimum of two days full load operation. The fuel storage may be larger under consideration of cost of storage and supply opportunities. Straw is received in bales and stored in an enclosed building in order to avoid exposure to moisture, wood pellets are stored in a closed silo, wood chips may be stored outside, but often under roof to limit exposure to rain.

Waste is received and stored in a closed building to avoid escape of odour and it is unloaded into a dedicated bunker from where a grab brings it to the feeding hopper.

1.3 Furnace

The furnace is where the fuel is injected, dried, pyrolysed and burnt and the energy content is converted to hot flue gas for subsequent uptake in the boiler. The typical furnace technologies can be divided into: grate firing, suspension firing (where the fuel is pulverized or chopped and blown into the furnace, optionally in combination with a fossil fuel) and different types of fluidised beds.

WtE facilities in Denmark are all grate fired. At WtE plants an afterburning chamber ensures that temperature and residence time requirements are met. During boiler start-up biomass or auxiliary burners in the furnace fired by oil or gas are needed to ensure the required temperature. During normal operation, no auxiliary fuel is added.

1.4 Boiler

The boiler is where the energy content of the flue gas is transferred by heat exchange to the heat media, which is usually hot water and in case of CHP, water and steam. As flue gas passes through the boiler, it is cooled, and the heat media is heated by heat exchange. In a heat only boiler, water is heated to supply the necessary district heating supply temperature.

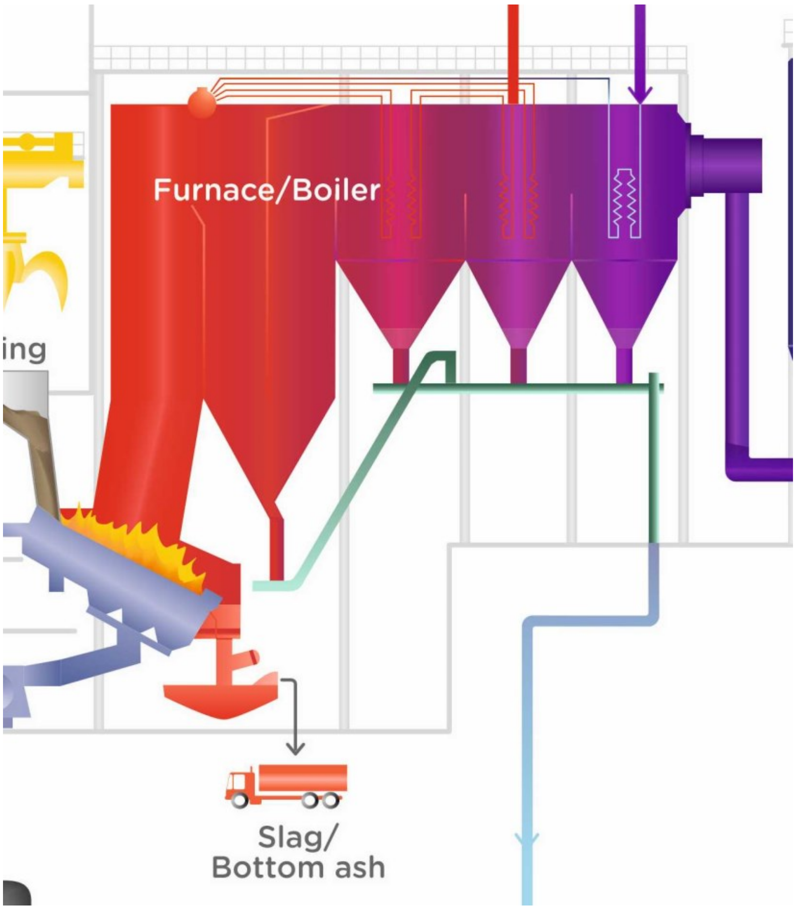


Figure 2 Furnace/boiler system

The output from the boiler of a CHP facility is superheated steam, i.e. steam that is heated above the boiling point. The plant includes feed water pumps supplying high pressure water to the boiler, an economiser, where the input water is heated towards the boiling temperature, evaporators, where the water is evaporated to steam, a drum vessel for separation of steam and water, and super heaters, where the steam is heated above the boiling temperature. Large biomass facilities may use different boiler types.

1.5 Turbine/generator

The turbine/generator set is only included in CHP (or power only) facilities. The superheated high-pressure steam from the boiler is led to the turbine where the energy content of the steam is converted to rotation energy in the turbine. Through its connection to the generator, the rotation energy is converted to electricity. The temperature and pressure of the steam decrease as the steam drives the rotation of the turbine blades. The low-pressure steam is extracted from the turbine to district-heating condensers at the pressure and temperature levels that suit the requirements of the district-heating network. The condensation heat is delivered to the district-heating network. This is different from a power-only facility where condensation happens at lower temperatures and the heat of condensation is wasted, e.g. in an air-cooled condenser. The power efficiency of a CHP facility is therefore lower than the corresponding power-only facility, but the total efficiency is much higher. Only CHP facilities are covered by the present technology sheets.

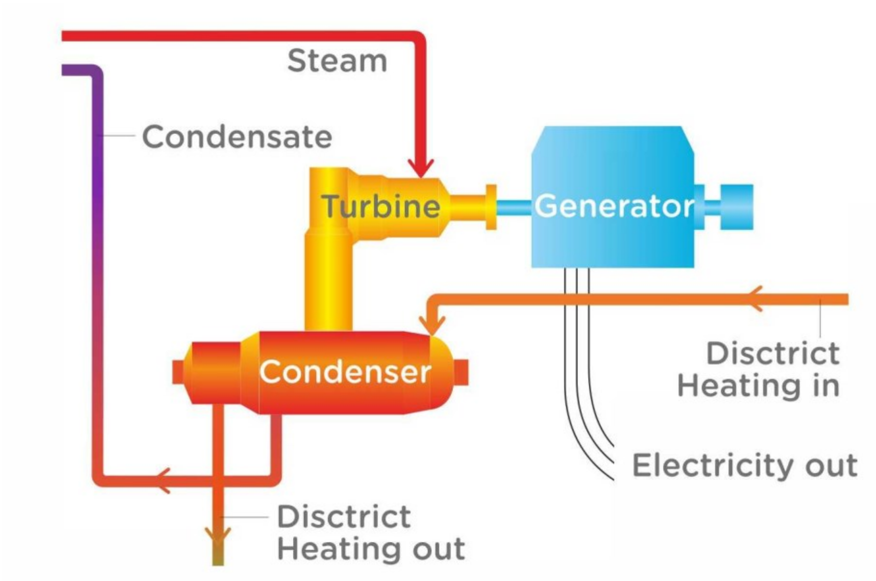


Figure 3 Turbine/generator system

1.6 Flue gas treatment (FGT)

The flue gas is treated to meet the emission requirements of biomass and waste, respectively. The FGT always includes a particle filter, either an electrostatic precipitator (ESP) or a bag house filter (BHF). Acid gases (HCl, SO_2 and HF) are mitigated in a dry process by injection of hydrated lime, for subsequent capture in a BHF, or in a wet scrubbing system. Using a wet scrubbing system reduces the amount of solid residue, but effluent process water must be treated before discharge to meet stringent emission levels.

NOx is mitigated by the SNCR or SCR process (SNCR and SCR are Selective Reduction of NOx by ammonia injection, by the respective non-catalytic or catalytic process). The SNCR process works by injection of ammonia in the furnace at around 900 °C. It has limited efficiency, and to meet stringent emission limit values it may be necessary to install the highly efficient catalytic SCR system. With biomass and waste an SCR system would usually be located downstream the main FGT (tail-end) or at least downstream the particle filter to avoid that the ashes in the flue gas deactivates the catalyst. In WtE dioxin and mercury may be captured by injection of activated carbon.

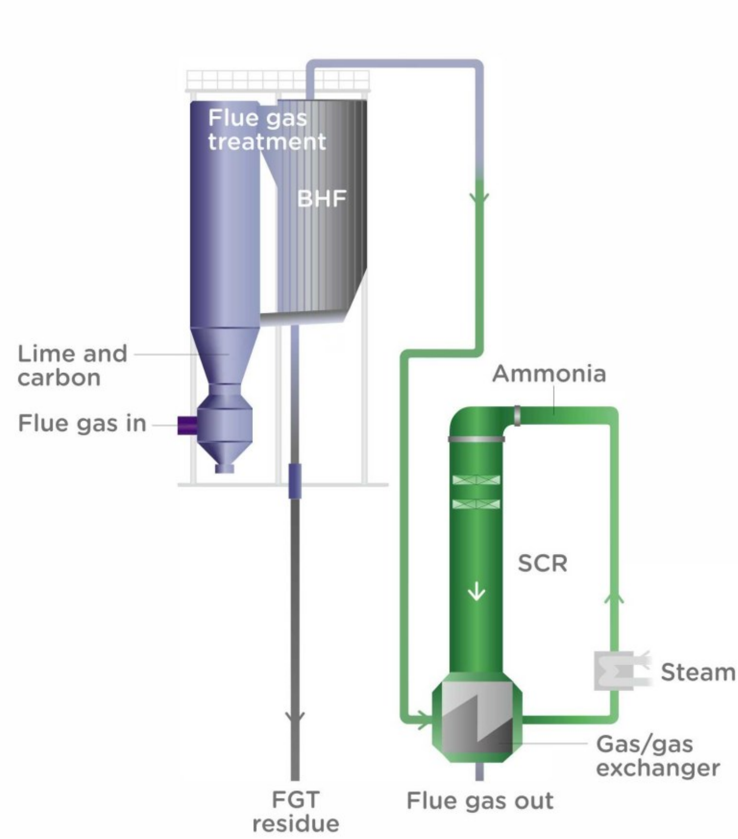


Figure 4 Flue gas treatment system (dry/semi-dry) including reactor with injection of hydrated lime, a bag house filter and an SCR system with gas/gas heat exchanger, steam reheater, ammonia injection and catalyst.

1.7 Handling of solid residues

Solid residues include incombustible matter (ash) and FGT residues. With biomass most of the ash is segregated in the boiler or particle filter and collected in a silo for disposal together with the FGT residue. In case of WtE the ash makes up 15-20 % of input waste, and around 90 % thereof leaves the facility as bottom ash, segregated from the furnace grate.

1.8 Flue gas condensation system

The flue gas condensation system is installed for increased heat recovery through condensation of the water vapours of the flue gas. Flue gas condensation is currently customary in WtE facilities and biomass fired facilities, particularly when using wood chips and similar relatively wet fuels.

Flue gas condensation may be arranged as a wet scrubbing system (Figure 5) in which the scrubbing liquid is cooled by heat exchange with district-heating water. The relatively cold district-heating water cools the scrubber and it is thereby heated. When the cooled scrubbing liquid meets the warmer flue gas that has been saturated with water vapour, the vapour condenses, thereby releasing the heat of condensation. The condenser may also be arranged with flue gas running in vertical tubes exchanging heat with district-heating water surrounding the tubes or plate heat exchangers in the flue gas path. The flue gas condensation system may be divided into two systems. First stage is direct condensation where heat recovery happens by direct heat exchange with district-heating water and in the second stage condensation is assisted by heat pumps. The heat recovery by direct condensation is limited by the district-heating return temperature. The lower the temperature, the higher the heat recovery. The heat pump allows cooling the flue gas and condensation of water vapour to quite low temperature (20-30 °C), corresponding to very high energy recovery at the expense of driving energy for the heat pump (typically steam or electricity). In the technology tables, only direct condensation is included to the level limited by the district-heating return temperature. The heat pump condensation potential is listed separately ("Additional heat potential for heat pump (%)"), and not included in the listed efficiencies. Section 0 below describes how to quantify the total efficiency for a biomass or WtE facility with flue gas condensation given a specific fuel and district heating temperature.

Running the flue gas through several wet scrubbers contributes to reaching very low emissions of HCl, $SO_{2,}$ dust, heavy metals and ammonia.

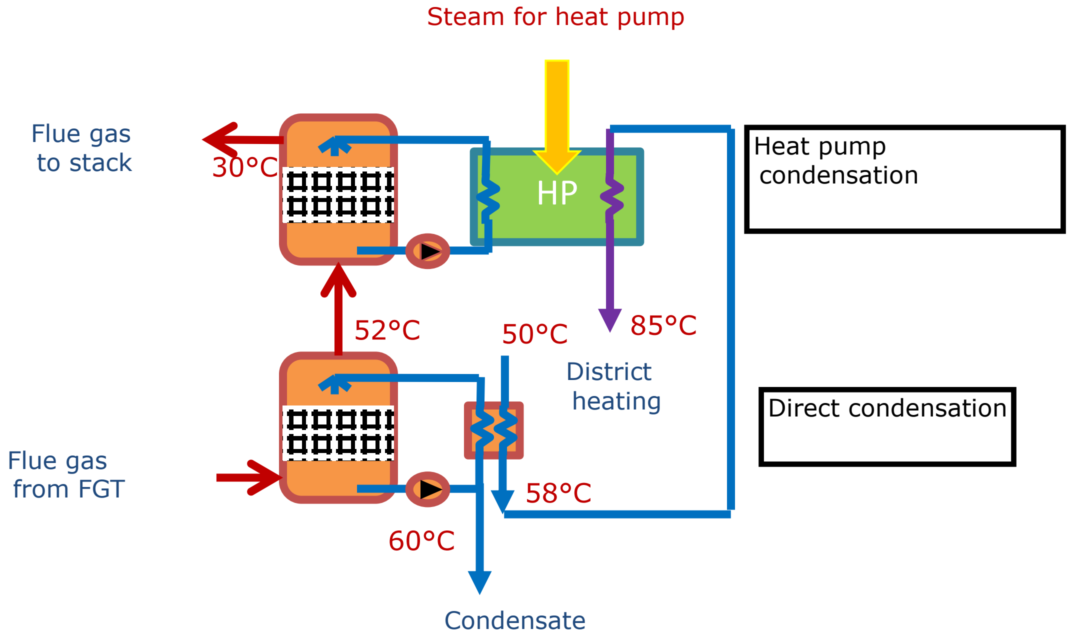


Figure 5 Flue gas condensation, direct and heat pump driven with 50°C district-heating return temperature, and typical WtE adiabatic scrubber temperature of 60°C.

1.9 Condensate and wastewater treatment

Process waste water from a wet scrubber (if included) must be treated prior to discharge. Treatment includes neutralisation, precipitation of heavy metal ions and filtering.

Condensate from flue gas condensation has low content of salts and pollutants when the condensation system is located downstream the FGT-system. Condensate treatment includes reverse osmosis to yield very clean water useful for industrial applications including boiler make-up water and make-up water for the district-heating network. The net water production may significantly exceed the original fuel moisture content, due to water formed from hydrogen and oxygen during combustion. For relatively wet fuel the excess water may be more than 500 kg per tonne of fuel input.

1.10 Combustion air humidification system

Combustion air humidification may to some extent substitute the use of heat pump driven condensation for increased heat production. Combustion air humidification works by adding water vapour to the combustion air, thereby increasing the content of water vapour in the flue gas as it enters the flue gas condensation system, in turn increasing the heat output of the direct flue gas condensation. The energy needed to generate the water vapour input to the combustion air is recovered from the last stage of the flue gas condensation system, at the temperature level below the district-heating temperature. This low temperature heat, at e.g. 50 °C, is used as heat source for evaporation of water in the combustion air humidification system.

The high-level effect of combustion air humidification is that the flue gas is cooled further than it is possible by heat exchange with the district-heating water, thereby representing an increase in energy recovery from the fuel. In the data tables it is assumed that combustion air humidification (if included) reduces the flue gas condensation temperature by 5 °C and 8 °C at DH return temperatures 40°C and 50°C, respectively. Currently no WtE facilities in Denmark is equipped with air humidification, but the system can be found in biomass fired facilities having flue gas condensation.

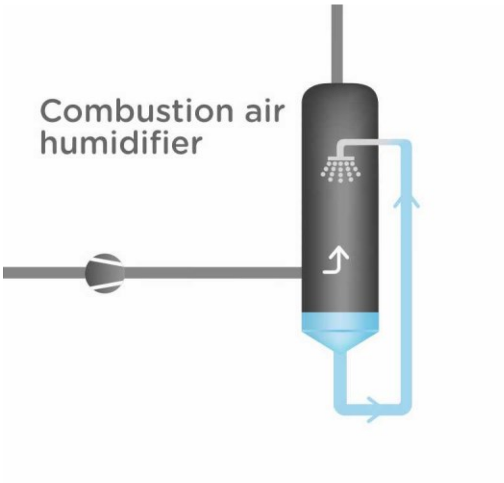


Figure 6 Combustion air humidifier, where water heated by a low-temperature source is evaporated into the combustion air flow.

Fuels

1.11 Biomass

The fuel input to biomass plants can in general be described as biomass; e.g. residues from wood industries, wood chips (from forestry), straw and energy crops. Combustion can in general be applied for biomass feedstock with average moisture contents up to 60% for wood chips and up to 25 % for straw dependent on combustion technology. The three types of biomass feedstock considered here are: Wood chips, wood pellets (white pellets), and straw. They are in several ways very different (humidity, granularity, ash content and composition, grindability, and density).

Sometimes it is possible to change fuel on a plant from one type of biomass to another, but it should be explicitly guaranteed by the supplier of the plant. Below is a broad description of biomass fuels.

Wood (particularly in the form of chips) is usually the most favourable biomass for combustion due to its low content of ash, nitrogen and alkaline metals, however typically with 45 % moisture for chips and below 10 % for pellets. Herbaceous biomass like straw, miscanthus and other annual/fast growing crops have higher contents of K, N, Cl, S etc. that lead to higher primary emissions of NO_x and particulates, increased ash generation, corrosion rates and slag deposits.

The amount of biomass available for energy production varies over time. From 2006 to 2014, the Danish straw production varied between 5.2 and 6.3 million tonnes per year (avg. 5.6 mil. t.), while the amount used for energy varied between 1.4 and 2 million tonnes (avg. 1.6 mil. t.).

Other exotic biomasses as empty fruit bunch pellets (EFB) and palm kernel shells (PKS) are available in the market; however, operating experience seems to be limited.

Forest residues are typically delivered as wood chips. Forest residues may also be delivered as pellets. During pellet production the fuel is dried to moisture content below 10%. As of today, the use of forest biomass for energy purposes accounts for only a small percentage of the total forest biomass production for, say, timber, paper, and other industrial purposes; thus typically biomass for energy purposes is (and must be) a residual product. This is also reflected by the fact that the current price (in $US/GJ) for wood products for energy purposes is much lower than the price for industrial applications of wood. Further to this there seems to be a growing interest for utilizing other types of surplus biomass from industrial productions like Vinery, olive oil production, sugar production, and more.

Wood chips are wood pieces of 5-50 mm in the fibre direction, longer twigs (slivers), and a fine fraction (fines). The quality description is based on three types of wood chips: Fine, coarse, and extra coarse. The names refer to the size distribution only, not to the quality. Fine particles as well as thin, long fibres may cause problems (in case the boiler is using grate firing). In the table below can be seen some typical (commercial) requirements for wood chips.

Typical sizes in a sample:

Name	Withhold on sieve	Share w%
Fines	<3 mm	<12
Small	3 < X < 8 mm	<25
Coarse	8 < X < 16 mm	No requirm
Extra coarse	16 < X < 45 mm	No requirm
Over size	45 < X < 63 mm	< 3
Over long 10	> 63 mm	< 6
Over long 20	100-200 mm lang	< 1,5

Ash concentrations must not exceed 2% on dry basis.

Existing district heating boilers in Denmark can burn wood-chips with up to 45-63 % moisture content, depending on technology. In 2014-2015, the actual moisture content was 40 % in average, varying between 25 and 55 % (ref. 1). Wood chips with high moisture content will often be mixed with dry wood chips.

Other possible fuels are chipped energy crops (e.g. willow and poplar) and chipped park and garden waste. The fuel quality must be in focus. Small particles must be avoided as well as long thin pieces. High moisture content of e.g. willow will increase the level of CO and PAH, so either the willow must be low in moisture content or it must be mixed with other fuels. Willow is known to take up Cadmium from the soil and thus increasing the concentrations in ash depending on where the willow has been growing. Poplar has been found to give problems in the boiler like “popcorn” in a combustion test. Chipped Park and garden waste must be of a good quality with low content of non-combustible materials, because of risks of blocking the grate (ref. 1).

Wood pellets are made from wood chips, sawdust, wood shavings and other residues from sawmills and other wood manufacturers. Pellets are produced in several types and grades as fuels for electric power plants and district heating (low grade), and homes (high grade). Pellets are extremely dense (up to the double of the density of the basic material) and can be produced with a low humidity content (below 5 % for high grade products) that allows easy handling (incl. long-term storage) and to be burned with high combustion efficiencies. When humidified, pellets are prone to auto-ignition. When exposed to mechanical treatment like conveyer transportation the pellets may break (or disintegrate) and release dust; this dust is highly explosive and therefore constitute a serious hazard. Documented sustainability is a serious issue for pellets in particular for plants above 20 MW thermal input. Both the disintegration of wood chips in hammer mills and the subsequent drying require energy and this must come from non-fossil sources (e.g. the wood itself).

Straw is a by-product from the growing of commercial crops, in North Europe primarily cereal grain, rape and other seed-producing crops. Straw is often delivered as big rectangular bales (Heston bales), typically approx. 5-700 kg each, from storages at the farms to the district heating plants etc. during the year pursuant to concluded straw delivery contracts.

1.12 Waste

The fuels used in WtE plants include mainly MSW and other combustible non-recyclable wastes. Biomass may be used mainly for starting up and closing down. Some plants in Denmark are feeding green waste from gardens and parks and challenging forest residues such as stubs. In addition, imported Refuse Derived Fuel (RDF) may be used as fuel. Other fuels include gasoil or natural gas for burners used mainly for start-up.

The fuel, waste, is characterised by being heterogeneous having large variation in physical appearance, heating value and chemical composition. The heating value of the waste fed to the furnace is a result of controlled mixing of available waste sources fed to the bunker of the WtE facility. It is usually in the range 7-15 MJ/kg, typically averaging 10-11 MJ/kg, referring to the lower heating value, LHV. For instance, the average heating value was 9.5 MJ/kg varying from 8-11 MJ/kg in 2014 in the WtE facility owned by Amager Resource Center (ARC) in the Copenhagen area. At the time ARC had about 50% waste from trade and industry, which is a high ratio in Denmark (Ref. 2).

The table below shows the trend of the heating value at Vestforbrænding I/S – the largest MSW plant in Denmark, and also located in the Copenhagen area.

Table 1 Development of lower heating value at Vestforbrænding, Denmark. Ref. 3.

Year	2011	2012	2013	2014	2015
MJ/kg	10,32	10,30	9,80	10,0	10,4

The heating value of the waste received at the WtE plants may be affected by increased focus on recycling, which on one hand may divert organic waste with relatively low heating value and on the other hand divert plastics, paper and wood with relatively high heating value. Many Danish WtE plants are importing RDF waste with relatively high heating value.

The energy model for the technology tables

A new approach has been introduced to generate the data tables for the biomass and waste combined heat and power (CHP) and heat only plants in this version of the tables. Due to the technological similarities, a common model has been used to populate the tables for biomass and waste data tables. This ensures a better consistency of the data spanning many scenarios and feedstocks. It is believed that this will eliminate skewness caused by differences in conditions for the reference plants, such as fuel and district-heating (DH) infrastructures, and reduce skewness caused by interpretation of reference data.

The energy efficiency estimates in the technology tables were calculated using a thermodynamic model of flue gas energy recovery to steam and district heating, including flue gas condensation (Ref. 4). A steam cycle model estimated the steam-to-power efficiency based on the steam parameters and turbine sizes. The same models were used to estimate efficiencies for the tables covering heat only and CHP plants for Waste-to-Energy (WtE) as well as biomass plant types at all size ranges. The different performances in the tables are thus a consequence of different plant design data assumed in each case and the fuel properties.

Table 2 shows the basis plant design assumptions made for the "2015" scenarios for different feed stocks. Conservative and optimistic variations of these assumptions were made to produce the future, "Upper" and "Lower" performance data. For example, "Lower" WtE models would assume steam at 400°C/40bar and no combustion air humidification, while "Upper 2050" assume 500°C/90bar, which will require advances in the technology. For small-to-medium biomass plants, "Upper" models assume the lower excess air offered by the Dall boiler already today etc.

Table 2 Base assumptions for "2015" model CHP plants for energy performance estimation.
"Upper" means that the feature is only assumed in the optimistic "Upper" scenarios of 2020 and 2050.

Fuel	Waste	Wood chips	Wood pellets	Straw
Firing system	Grate	Grate/ CFB(large)	Suspension	Grate
Live steam, CHP	425°C/50bar	540°C/90bar	560°C/90bar	540°C/90bar
Flue gas T after steam boiler	160°C	130°C	130°C	130°C
Excess air ratio	1,5	1,3	1,3	1,3
Boiler losses other than flue gas (% of LHV)	2%	2%	2%	2%
Turbine losses (gear/generator) (% of gross power), CHP	3%	3%	3%	3%
Flue gas condensation	Yes	Yes	Yes	Yes
Combustion air humidification	"Upper"	Yes	Yes	Yes
Flue gas cleaning type	Wet	Dry	Dry	Dry
NOx abatement (small and medium size)	SNCR	SNCR	SNCR	SNCR
NOx abatement (large facilities)	SNCR	SNCR	SCR	SCR

The total efficiency of plants with flue gas condensation is calculated assuming “direct condensation”, where the condensation heat is recovered directly with the available district heating water without the use of heat pumps.

DH plants share base assumptions with the CHP plants, except that live steam parameters are not applicable, and the turbine losses do not exist for these plants.

At some plants, condensation heat recovery is augmented by cooling the flue gas further, typically to 30 °C using heat pumps. In the tables, the row “Additional heat potential for heat pump (%)” contains the additional heat energy that a heat pump would recover from the flue gas by cooling it further to 30 °C. The so produced additional heat is the sum of this energy amount and any external driving energy (electricity or steam) supplied to drive the heat pump. The efficiencies listed in the data tables do not include the contribution from heat pump driven condensation, and the heat pump investments are not included in the listed investments.

As an example, the plant like Amager Bakke would belong to the “Large WtE” plants with high DH temperature levels of 50/100°C. The 2015 data from the tables provide name plate values of 21.1% for power and 74.4% for heat, summing up to 95.5%. The additional heat from heat pumps is given as 10.0%, increasing the sum to 105.5%.

Without heat pumps, the actual design power efficiency of 25 % at Amager Bakke is higher than the 21.1 % that the tables suggest. This is mainly due to the high steam parameters (440°C/70bar), and the lower forward temperature of the actual district heating water (85°C instead of the 100°C assumed in the tables). The total design efficiency is 95 % without using heat pumps, which is on level with the 95.5% from the tables.

With heat pumps activated, the total efficiency at Amager Bakke reaches 107%. This is slightly higher than the 105.5 % in the tables, which is due to the flue gas being cooled to 20 °C instead of 30 °C, and some additional component cooling heat recovery is performed by the installed heat pumps as well. The power efficiency is reduced to 22.5 % when using the heat pumps, mainly due to the transfer of driving steam for the heat pumps. The system coefficient of performance (COP) of the heat pump system is estimated at around 5.5, meaning that 5.5 MWh of heat is generated for one MWh reduction of electricity production.

The loss of power production caused by the steam consumption of the heat pumps is system specific and cannot be tabulated here. If electrically driven heat pumps had been used instead, the power production loss would be avoided, but instead the heat pump would consume power themselves. Please refer to the heat pump technology sheets.

1.13 Total energy efficiency determination with flue gas condensation

Flue gas condensation is a technology that can significantly increase the heat efficiency of biomass and WtE plants by recovering the heat of condensation from water vapour in the flue gases. It is now implemented at the majority of the WtE plants and at many biomass plants in Denmark.

The heat of condensation is not included in the heating value definition of the lower heating value, LHV, which is usually used in Europe as basis for defining the energy input. Thus, total efficiencies based on LHV at plants with flue gas condensation may exceed 100%. Further the total efficiency of such plants can vary significantly for different fuels with different compositions and moisture contents when using the LHV as the basis.

For flue gas condensation the relevant heating value definition to describe the heat recovery and the total plant efficiency is the higher heating value (HHV), which takes into account the energy recovery potential from condensation. Thus, we will in the specific section below need to make references to the HHV. The rest of the technology data sections as well as all the data tables will refer to the usual LHV only.

The total HHV-based efficiency of a given plant with flue gas condensation is almost the same for any fuel, when the flue gasses are cooled, and water vapour condensed to a certain temperature. The total HHV-based efficiency with flue gas condensation depends mainly on the temperature of the district heating return water, which is used to recover the low temperature heat through heat exchange.

Figure 7 shows the HHV-based total gross efficiency for typical biomass plants and WtE plants. This curve is generally applicable to such plants, for CHP as well heat only configurations. Biomass plants with flue gas condensation have slightly higher HHV-based gross efficiencies because they typically operate with lower excess air ratios than WtE plants. The dashed boiler efficiency indications in Figure 7 show the no-condensation lower efficiency limit, which is fuel specific. Wood chips were selected for the example to give a low lower limit.

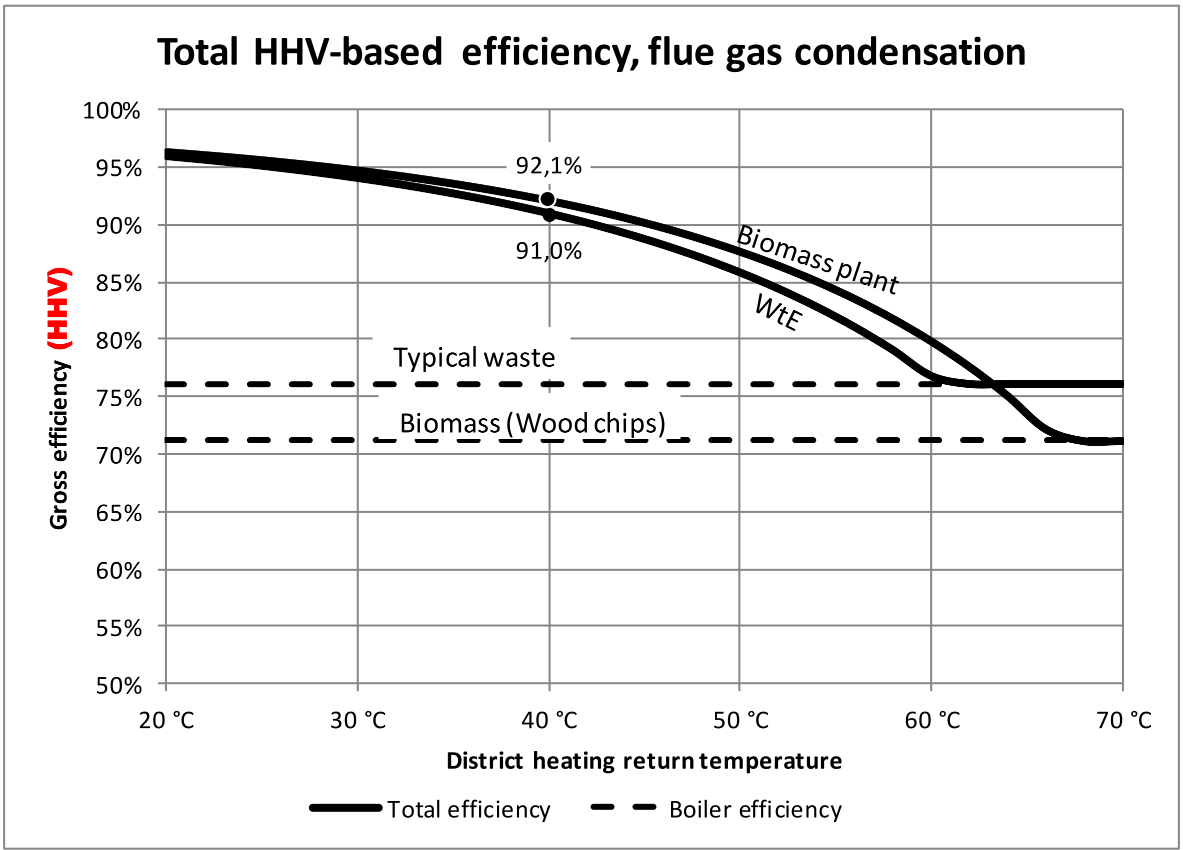


Figure 7.Total HHV-based efficiency estimate for WtE plants[11] and biomass plants[12] given varying district heating return temperatures (Ref. 5) – or temperature of the cold media of a heat pump.

Figure 7 can be used generally with good accuracy to estimate the total efficiency (based on HHV) of a WtE or solid biomass plant equipped with flue gas condensation, based only on the available district heating return temperature. The estimate is even valid for marginal efficiencies of single waste fractions such as organic waste, paper, plastics etc. The conversion to the usual LHV-based total efficiency is straight-forward. As an example, typical municipal solid waste with a LHV of 10.6 MJ/kg and a HHV of 12.2 MJ/kg treated at a plant with flue gas condensation fed with 40 °C DH water would according to Figure 7 have a total efficiency of 91.0% based on HHV. This can be calculated to the LHV-based gross total energy efficiency as: $91.0\% \cdot \frac{12.2\ \mathrm{MJ/kg}}{10.6\ \mathrm{MJ/kg}} = 104.7\%$. This value can be found in the WtE "2015" tables. For wet organic waste with a HHV of 6.5 MJ/kg and LHV of 4.4 MJ/kg treated at the same plant, gross total energy efficiency would be $91.0\% \cdot \frac{6.5\ \mathrm{MJ/kg}}{4.4\ \mathrm{MJ/kg}} = 134.9\%$. Table 3 shows examples of gross total efficiencies calculated the same way for different fuels at WtE and biomass plants connected to district heating networks with return temperatures of 50, 40 and 30°C.

[11] Assumptions for WtE: Excess air ratio λ=1.5. Ash content 25% of dry matter. Flue gases cooled to 2°C above the DH return temperature.

[12] Assumptions for biomass: Excess air ratio λ=1.3. Wood chips with an ash content of 2% of dry matter. Flue gases cooled to 2°C above the DH return temperature.

Table 3. Gross total efficiencies for different fuels at biomass and waste fired plants with access to different DH return temperatures using flue gas condensation.

Gross total efficiencies with flue gas condensation	Heating value		Total efficiency (LHV)		
Fuel or fuel fraction	LHV [MJ/kg]	HHV [MJ/kg]	DH 50°C	DH 40°C	DH 30°C
WtE configuration HHV efficiency (from Figure 1)			*85.8%*	*91.0%*	*94.1%*
Mixed waste 10.6 GJ/t (31% moisture)	10.6	12.2	**98.8%**	**104.7%**	**108.3%**
Organic waste (70% moisture)	4.4	6.5	**127.3%**	**134.9%**	**139.5%**
Green waste (50% moisture)	9.5	11.5	**103.4%**	**109.6%**	**113.3%**
Paper	11.1	12.6	**97.4%**	**103.3%**	**106.8%**
Plastic	35.0	37.5	**91.9%**	**97.5%**	**100.8%**
Biomass configuration HHV efficiency (from Figure 1)			*87.7%*	*92.1%*	*94.7%*
Wood chips (50% moisture)	8.1	10.0	**107.7%**	**113.1%**	**116.3%**
Wood chips (40% moisture)	10.3	12.0	**102.5%**	**107.7%**	**110.8%**
Wood pellets (5% moisture)	17.7	19.0	**94.3%**	**99.0%**	**101.9%**
Straw (11% moisture)	15.0	16.4	**95.8%**	**100.6%**	**103.5%**

As some plants, large heat pumps have been installed to supply condenser cooling water at even lower temperatures than the DH return temperature in order to further increase the heat recovery. In these cases, the total efficiency can still be read from Figure 7 by replacing the district heating return temperature on the x-axis by the (lower) chilled water temperature from the heat pump. The use of a heat pump to provide a cold media for extended flue gas condensation is considered an add-on, the feasibility of which is judged as a separate project (cf. technology sheets on heat pumps). The heat pump constitutes most of the necessary additional investment.

Even higher total efficiencies can be achieved by recovering the heat from component cooling at the plant, which is usually lost. This would require the use of heat pumps. Recovery of component cooling energy is being implemented both at the WtE plants Amager Bakke and Fjernvarme Fyn in Odense during 2017, both reaching total net total efficiencies around 105-110 %.

All efficiencies in the main data tables of all ENS technology data sheets are given based on the usual LHV basis for the specifically assumed waste and biomass composition. Given other waste or biomass compositions, the total efficiency at plants with flue gas condensation is much more accurately estimated using the table or procedure described above with the given fuel. The power efficiency should however be taken directly from the technology data sheets, as it is not significantly affected by flue gas condensation.

References:

1. Input and comments several places by Dansk Fjernvarme, 2015, 2017

2. ARC, Kirstine Hansen, Email 2015-05-07.

3.Vestforbrænding I/S, Grønt regnskab (Green accounts) of 2013 and 2015, respectively. (http://www.vestfor.dk/Om-Vestforbraending/Nogletal)

4. Veronica Martinez-Sanchez, Tore Hulgaard, Claus Hindsgaul, Christian Riber, Bettina Kamuk, Thomas F. Astrup; Estimation of marginal costs at existing waste treatment facilities, Article in Waste Management 50, p 364-375· March 2016.

5. Calculations by Rambøll. Not published.