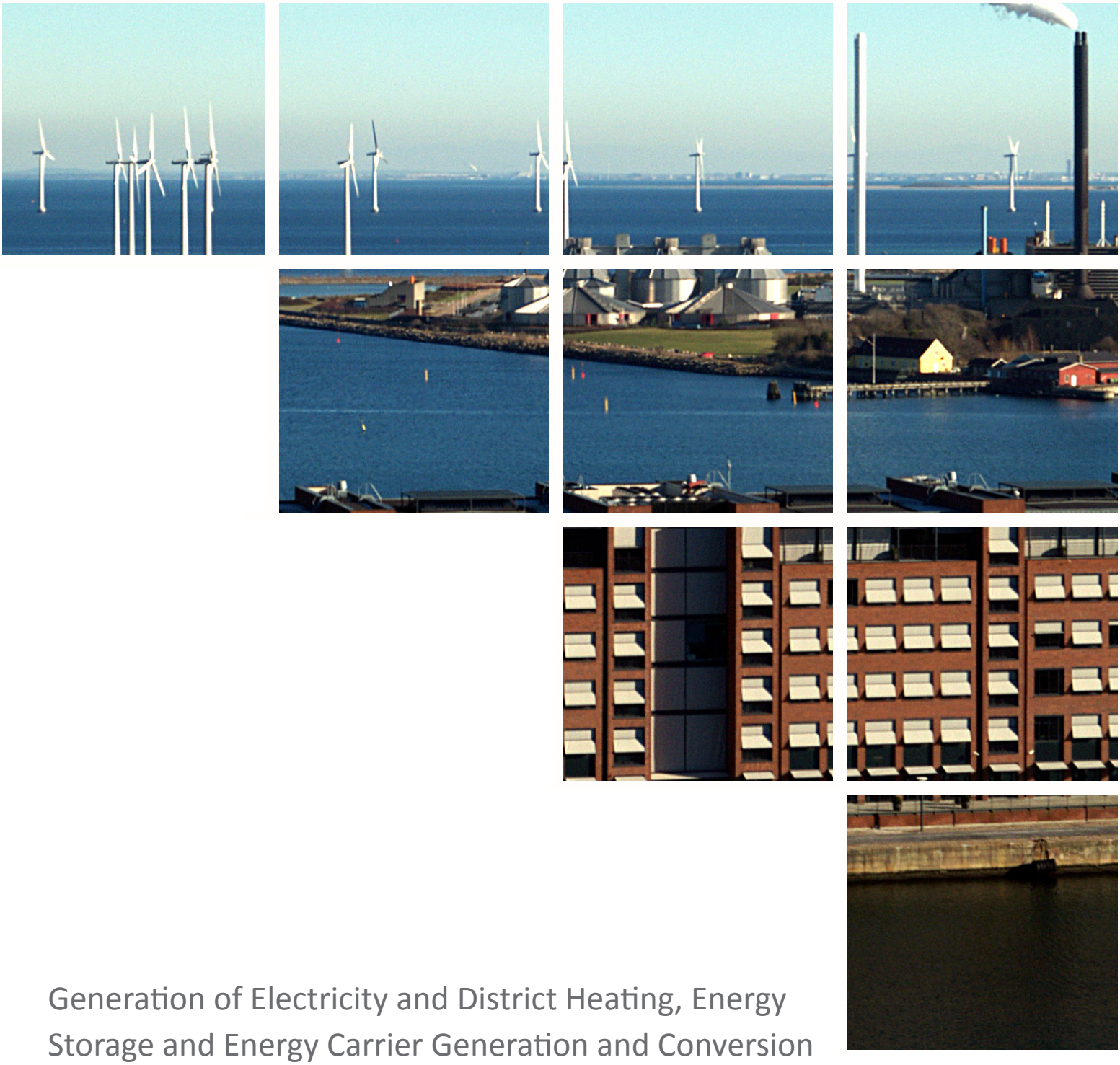

Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion

TECHNOLOGY DATA FOR ENERGY PLANTS

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ENERGINET/DK

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Technology Data
for
Energy Plants

Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion

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INTRODUCTION

The Danish Energy Agency and Energinet.dk, the Danish electricity transmission and system operator, have at regular intervals published a catalogue of energy producing technologies. The previous edition was published in June 2010. This report presents the results of the most recent update.

The primary objective of publishing a technology catalogue 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, and 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 has not been the intention to establish a comprehensive catalogue, including all main gasification technologies or all types of electric batteries. Only selected, representative, technologies are included, to enable generic comparisons of e.g. thermal gasification versus combustion of biomass and electricity storage in batteries versus hydro-pumped storage.

It has finally been the intention to offer the catalogue for the international audience, as a contribution to similar initiatives aiming at forming a public and concerted knowledge base for international analyses and negotiations.

A guiding principle for developing the catalogue has been to rely primarily on well-documented and public information, secondarily on invited expert advice. Since many experts are reluctant in estimating future quantitative performance data, the data tables are not complete, in the sense that most data tables show several blank spaces. This approach has been chosen in order to achieve data, which to some extent are equivalently reliable, rather than to risk a largely incoherent data set including unfounded guesstimates.

Cross-cutting comparisons between technologies will reveal inconsistencies, e.g. that a small version of a technology is cheaper (in €/kW) than a bigger version. This reflects diversity with several causes:

- Technologies are established under different conditions. A typical example is the investment costs of 17 off-shore wind farms being established or planned in 2009. Taking all 17 projects, the investment cost varies from 1.9 to 20 M€/MW. The 20 M€/MW project is a demonstration project (floating wind turbines). The second-most expensive (4.2 M€/MW) is also a demonstration project, while the data for the two cheapest wind farms (1.9 and 2.0 M€/MW) are considered unreliable. The remaining 13 projects, costing 2.3 – 3.8 M€/MW, have all been considered the best choice by their respective investors. The available data does not allow telling, whether one cost estimate is more ‘correct’ than another. The weighted average is 3.14 M€/MW, differing from the arithmetic average of 3.05 M€/MW. The cost figure may thus be stated as 3.1 M€/MW +/- 25%.
- Investors have different views on economic attractiveness and different preferences. Some decisions are not based on mere cost-benefit; e.g. some will tender for a good architect to design their building, others will buy the cheapest building.

- Environmental regulations vary from country to country, and the parts of the investment costs, which are environment-related, are often not reported.
- Expectations to the future development vary.
- Different authors have different views on how to report technical performance and costs. E.g. some report the nameplate electricity efficiency, while others report the average annual efficiency. The details on how to understand the data is often not reported.
- 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.

Some inconsistencies are particularly noteworthy. These are highlighted by framed text-boxes.

The current update has been developed with an unbalanced focus, i.e. most attention to technologies which are most essential for current and short-term future analyses. Therefore, some data rely on sources, which may be antiquated. However, since all data are referenced, differences in data quality appear explicitly.

INTRODUCTION IN DANISH

Energistyrelsen og Energinet.dk udgav i juni 2010 et teknologikatalog for el- og varmeproduktionsteknologier, 'Technology Data for Energy Plants'. Det nuværende katalog er en opdateret og lettere udvidet og omstruktureret udgave af 2010-kataloget.

Et hovedformål med at opdatere teknologikataloget er at sikre et ensartet, alment accepteret og aktuelt grundlag for planlægningsarbejdet og vurderinger af forsyningssikkerhed, beredskab, miljø og markedsudvikling hos bl.a. det systemansvarlige selskab og Energistyrelsen. Dette omfatter for eksempel fremskrivninger, scenarieanalyser og teknisk-økonomiske analyser.

Desuden vil teknologikataloget være 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.

Teknologikataloget vil endelig kunne anvendes i såvel nordisk som internationalt perspektiv. Det vil derudover kunne bruges som et led i en systematisk international videns-opbygning 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.

1. GUIDELINE

1.1. Introduction

This chapter serves to assist readers in understanding and assessing the presented information.

Generally, technologies described in this catalogue are mature technologies. The intention has been to present data for proven technologies, which have been sold in more than a handful of units at market terms. Therefore, the costs do not include the first-of-a-kind premium. There are, however, few exceptions, e.g. CCS (carbon capture and storage), wave energy and some storage technologies. In such cases, performance and cost data have been assessed, as if technologies were in mature conditions.

The boundary for both performance data and costing are 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 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 transmission systems receiving their energy deliveries. So a MW of electricity is the net electricity delivered, i.e. the gross generation minus the auxiliary electricity consumed at the plant. Hence, efficiencies are also net efficiencies.

Each technology is described by a separate technology sheet, following the format explained below.

1.2. Qualitative description

One to three pages give the key characteristics of the technology. Typical paragraphs are:

Brief technology description
Very brief description for non-engineers on how the technology works and for which purpose.

Input
The main raw materials, primarily fuels, consumed by the technology.

Output
The forms of generated energy, i.e. electricity, heat, bio-ethanol etc.

Typical capacities
The stated capacities are for a single ‘engine’ (e.g. a single wind turbine or a single gas turbine), not a power plant consisting of a multitude of ‘engines’ such as a wind farm.

Regulation ability
In particular relevant for electricity generating technologies, i.e. what are the part-load characteristics and how fast can they respond to demand changes.

Advantages/disadvantages
Specific advantages and disadvantages relative to equivalent technologies. Generic advantages are ignored; e.g. renewable energy technologies mitigate climate risk and enhance security of supply.

Environment
Particular environmental characteristics are mentioned, e.g. special emissions or the main ecological footprints.

The ecological footprints cannot be used to compare technologies. For example, photovoltaic cells have few and small footprints, one of the major ones being radioactive waste. However, this does not mean that there is more radioactive waste from solar electricity than coal-fired electricity. It only means that radioactive waste is one footprint from photovoltaic cells which is more important than other footprints from the same technology.

The energy pay back 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 of the technology.

Energinet.dk, DONG Energy and Vattenfall have in 2009 completed a thorough life cycle assessment (LCA) of the Danish electricity system in 2008. This includes LCA of all pertinent electricity generating technologies. The report can be downloaded from www.energinet.dk.

Research and development
This is a very brief listing of the most important current challenges, often from a Danish perspective.

Examples of best available technology
A brief mentioning of recent technological innovations in full-scale commercial operation.

Additional remarks

References

1.3. Quantitative description

To enable comparative analyses between different technologies it is imperative that data are actually comparable. As an example, economic data shall be stated in the same price level. Also, it is important to compare technologies at equal footing, e.g. either gross generation capacity or net capacity (gross minus own consumption).

It is essential that data be given for the same years. Year 2015 is the base for the present status of the technologies (best available technology commissioned in 2015), whereas data for expectations to future developments are given at years 2020, 2030 and 2050.

Below is shown a typical datasheet, containing all parameters used to describe the specific technologies. For several technologies, the datasheet have been adjusted to suit the specific characteristics.

Typical datasheet:

Technology	**Name of technology**					
	2015	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Generating capacity for one unit (MW)						
Electricity efficiency, net (%)						
Availability (%)						
Technical lifetime (years)						
Construction time (years)						
Environment						
NO_X (g per GJ fuel)						
CH4 (g per GJ fuel)						
N2O (g per GJ fuel)						
Financial data						
Nominal investment costs (M€/MW)						
Fixed O&M (€/MW/year)						
Variable O&M (€/MWh)						

References:

1

2

Notes:

A

B

All data in the datasheets 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

Before using the data please note that essential information may be found in the notes below the table.

Energy/technical data

Generating capacity for one unit

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

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.

The unit MW is used for electric generation capacity, whereas the unit MJ/s is used for fuel consumption and heat generation.

Energy efficiencies

The total efficiency equals the total delivery of electricity plus heat at the fence (i.e. excluded own consumption) divided by the fuel consumption. The efficiency is stated in per cent at ambient conditions; air 15 ^{o}C and water 10 ^{o}C.

The electricity efficiency equals the total delivery of electricity to the grid divided by the fuel consumption. The efficiency is stated in per cent.

The efficiencies are determined at full load (100 %), continuous operation, on an annual basis, taking into account a typical number of start-up's and shut-down's. Some CHP plants employ cooling towers to dismiss surplus heat during the summer. This is not included in the data.

Often, the electricity efficiency is decreasing slightly during the operating life of a thermal power plant. This degradation is not reflected in the stated data. As a rule of thumb you may deduct 2.5 – 3.5 % during the lifetime (e.g. from 40 % to 37 %). Specific data are given by ref. 3.

Start-up

The warm start-up time – used for boiler technologies – is defined as a start, where the water temperature in the evaporator is above 100 ^{o}C, which means that the boiler is pressurized.

Cogeneration values

The C_b coefficient (back-pressure coefficient) is defined as the maximum power generating capacity in back-pressure mode divided by the maximum heat capacity.

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. See also Annex 1.

Values for C_b and C_v are given – unless otherwise stated – at 100 ^oC forward temperature and 50 ^oC return temperature for the district heating system. For supercritical steam turbines the values should also be given at 80/40 ^oC.

Average annual plant capacity factor

The average annual net generation divided by the theoretical annual net generation, if the plant were operating at full capacity all year around. 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.

Forced and planned outage

Forced outage is defined as number of weighted forced outage hours divided by the sum of forced outage hours and operation hours, multiplied by 100. The weighted forced outage hours are the hours caused by unplanned outages, weighted according to how much capacity was out.

Forced outage is given in per cent, while planned outage is given in weeks per year.

The availability is determined as 1 minus (weighted forced outage hours + planned outage hours) / 8760; possibly in per cent.

Construction time

Period from financial closure – i.e. financing secured and all permits are at hand - until commissioning completed (start of commercial operation).

Environment

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

SOx: For technologies, where de-sulphuring equipment is employed (typically large power plants), the degree of desulphuring (%) is stated.

The following sulphur contents of fuels can be applied:

	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

NOx: grams per GJ fuel. NOx equals NO_2 + NO, where NO is converted to NO_2 in weight-equivalents.

Greenhouse gasses: CH_4 and N_2O in grams per GJ fuel.

Financial data

Financial data are all in Euro (€), fixed prices, price-level 2011.
Several data originate in Danish references. For those data a fixed exchange ratio of 7.42 DKK per € has been used.

The previous catalogue (from 2010) was in 2008 prices. Several data have been updated by applying the general inflation rate in Denmark, so that 2008 prices been multiplied by 1.0478.

The IEA publishes at regular intervals a report on "Projected costs of generating electricity". The latest edition being from 2010 (ref. 4) is based on costs data for 190 power plants in 21 countries. A key observation was that costs "*vary widely from country to country; even within the same region there are significant variations in the cost for the same technologies… It is clearly impossible to make any generalisation on costs above the regional level; but also within regions (OECD Europe, OECD Asia), and even within large countries (Australia, United States, China or Russia), there are large cost differences depending on local cost conditions (e.g. access to fossil fuels, availability of renewable resources, different market regulations, etc.)… In particular, the cost for renewable energy technologies shows important variations from country to country and, within each country, from location to location*". In this perspective, the present publication has been developed with an emphasis on European data sources.

Investment costs

The investment cost or initial cost is often reported on a normalized basis, e.g. cost per kW. The nominal cost is the total investment cost divided by the net generating capacity, 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 electric capacity and electricity generation.

Different organizations employ different systems of accounts to specify the elements of an investment cost estimate. As there is no universally employed nomenclature, investment costs do not always include the same items. Actually, most reference documents do not state the exact cost elements, thus introducing an unavoidable uncertainty that affects the validity of cost comparisons. Also, many studies fail to report the year (price level) of a cost estimate.

In this report, the intension is that investment cost shall include all physical equipment, typically called the engineering, procurement and construction (EPC) price or the overnight cost. Infrastructure or connection costs, i.e. electricity, fuel and water connections, are also included.

The cost of land, the owners' predevelopment costs (administration, consultancy, project management, site preparation, approvals by authorities) and interest during construction are not included. The cost to dismantle decommissioned plants is also not included, assuming that the decommissioning costs are offset by the residual value of the assets.

Costs of energy equipment surged dramatically in 2007-2008. The trend was general and global. One example is combined cycle gas turbines (CCGT): "*After a decade of cycling between $400 and $600 a kW installed EPC prices for CCGT increased sharply in 2007 and 2008 to peak at around $1250/kW in Q3:2008. This peak reflected tender prices: no actual transactions were done at these prices. Prices have since fallen, with current prices now around $1050/kW*" (ref. 3). Such unprecedented variations obviously make it difficult to benchmark data from the recent five years, but a catalogue as the present cannot be produced without using a number of different sources from different years. The reader is urged to bear this in mind, when comparing the costs of different technologies.

The per unit cost of larger power plants are usually less than that of smaller plants. This is called the 'economy of scale'. The proportionality was examined in some detail in the article "Economy of Scale in Power Plants" in the August 1977 issue of Power Engineering Magazine (p. 51). The basic equation 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

For many years, the proportionality factor averaged about 0.6, but extended project schedules may cause the factor to increase. However, used with caution, this rule may be applied to convert data in this catalogue to other plant sizes than those stated. It is important that the plants are essentially identical in construction technique, design, and time frame and that the only significant difference is in size.

For very large-scale plants, like coal and nuclear power plants, we may have reached a practical limit, since very few investors are willing to add increments of 1000 MW or above. Instead, multiple unit configurations can provide sufficient savings through allowing sharing of balance of plant equipment and support infrastructure. Typically, about 15 % savings in investment cost per MW can be achieved for gas combined cycle and big steam power plant from a twin unit arrangement versus a single unit (ref. 3). The financial data in this catalogue are all for single unit plants (except for wind farms and solar PV), so one may deduct 15 % from the investment costs, if very large plants are being considered.

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 to strengthen or expand the local grid and/or transformer-station. The costs vary much depending on the type and size of generator and local conditions. For planning purposes one may apply a generic cost of 0.13 M€ 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 aggregate capacity addition may be smaller than the sum of the individual expansions, since peak-loads do not occur simultaneously.

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

A special approach has been applied for investment costs of electricity stores. Where sufficient data have been identified, the investment cost is separated into two components:

1. The equipment, which is primarily determined by the amount of energy stored (i.e. the volume of the cavern for compressed air energy storage, the water volume behind the dam of a pumped hydropower plant, or the naked electric battery).
2. The equipment, which determines how much power the system can deliver (i.e. the turbine of compressed air energy storage, the hydropower turbine, or the converter of a battery system).

To determine the total investment cost, these two components shall be added.

For example, the investment cost of a compressed air energy store may be stated as 0.2 M€/MWh plus 1.6 M€/MW. A 10 MW plant, which shall be able to discharge up to 5 hours full capacity in one charge-discharge cycle (i.e. storage capacity 50 MWh), costs:

$$0.2 \cdot 50 + 1.6 \cdot 10 = 10 + 16 = 26\ million\ €$$

Operation and maintenance (O&M) costs

The fixed share of O&M (€/MW/year) includes all costs, which are independent of how the plant is operated, e.g. administration, operational staff, planned and unplanned maintenance, payments for O&M service agreements, network use of system charges, property tax, and insurance. Re-investments within the scheduled lifetime are also included, whereas re-investments to extend the life are excluded.

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

Fuel costs are not included. Own electricity consumption is included for heat only technologies, except for heat pumps.

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.

The O&M costs are calculated by dividing the total annual costs, fixed and variable, with the net generating capacity and net annual generation respectively, whether electricity or district heat. For electricity generating technologies, incl. combined heat and power generation, the denominator is electric capacity and electricity generation. For heat only technologies, the denominator is heat generating capacity and heat generation.

Often, the reference documents do not distinguish between fixed and variable O&M costs. Then the total O&M costs are given, typically in €/MWh.

Cost drivers
Determining the cost of energy generation is not an easy matter. Forecasting the cost is subject to even larger bands of uncertainty. Therefore, many studies have sought to determine the most important drivers of cost. For capital intensive technologies, such as nuclear power and most renewables, the largest uncertainty lies with the capital expenditures, the build time and the average annual capacity factor. For expensive fuel converters, the primary uncertainty is related to the efficiency of fuel conversion, the price of fuel and the possible carbon penalty. A major driver in reducing prices is likely to be increased competition from Chinese and other low cost manufacturers, compared with European, North American and Japanese manufacturers. Mott MacDonald (ref. 3) has provided an excellent overview of these and many other cost drivers.

The present study has not sought to develop a new understanding of cost drivers or to utilize one particular methodology. The approach has rather been to analyse what others have forecasted and then select the data, which appear most well-founded and most mainstream. For this reason the study has made a virtue out of referencing information and data to the largest extent possible, allowing the reader to make his/her own assessment.

Regulation ability

The regulation is described by three parameters:

A. Fast reserve, MW per 15 minutes.
B. Regulation speed, MW per minute.
C. Minimum load, per cent of full load.

For several technologies, these parameters do not make sense, 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.

1.4. Definitions

A steam process can be of different nature:

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**: Same as condensation, but the steam pressure (and temperature) in the condenser is higher, so that the temperature of the coolant becomes sufficiently high to be used for industrial processes or district heating. A back-pressure turbine produces electricity and heat, at an almost constant ratio.
3. **Extraction**: Same as condensation, but steam can be extracted from the turbine to produce heat (equivalent to back-pressure). Very flexible, no fixed ratio between electricity and heat.

1.5. References

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

1. Danish Energy Agency: ”Forudsætninger for samfundsøkonomiske analyser på energiområdet” (Generic data to be used for socio-economic analyses in the energy sector), May 2009.
2. “UK Electricity Generation Costs Update”, Mott MacDonald, June 2010; commissioned by the Department of Energy and Climate Change, United Kingdom.
3. “Projected Costs of Generating Electricity”, International Energy Agency, 2010.

2. COMPARISON OF FINANCIAL KEY FIGURES

This chapter presents the financial key figures for all technologies, i.e. specific investment costs and operation and maintenance costs. Data intervals in the technology sheets have here been shortened to medium values.
All data are in constant 2011 price level.

2015		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
01	Advanced Pulverized Fuel Power Plant						
	- Coal fired	2,04		7,0		57200	2,0
	- fired by wood pellets	2,04				57200	2,0
	- natural gas fired	1,40				38000	0,82
03	Rebuilding coal power plants to biomass						
	- wood pellets	0,18					
	- wood chips, straw	0,42					
	- wood chips, dried	0,52					
04	Gas Turbine Single Cycle						
	- large scale plant	0,65		2,4			
	- medium scale plant	1,20		7,0			
	- mini gasturbines	1,75		9,0			
	- micro gasturbines	1,20		15,0			
05	Gas Turbine Combined Cycle						
	- steam extraction	0,87				30000	2,5
	- back-pressure	1,35		2,5			
06	Gas Engines	1,25		9,2			
07	CO2 Capture and Storage	3,30				79500	3,75
08	Waste-to-Energy CHP Plant	8,50				16500	23
09	Biomass CHP, Steam Turbine						
	- woodchips (medium)	2,60				29000	3,9
	- woodchips (small)	4,25	3,5		150000		
	- straw (medium)	4,00				40000	6,4
	- straw (small)	5,15	4,0				
10	Stirling Engines, Gasified Biomass	5,00				32000	26

2015		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
20	Wind Turbines - Onshore						
	- large	1,40		14			
	- medium	1,40		14			
	- small (> 5 kW)	2,15					
	- small (< 5 kW)	4,75		30			
21	Wind Turbines - Offshore	3,10		19			
22	Solar Photovoltaic Cells, Grid-connected	2,00		34			
23	Wave Power	7,80		20,0			
30	Solid Oxide Fuel Cells						
	- Continuous Power Generation	5,00		25,0			
	- Balancing Plant	2,00		25,0			
31	Proton Exchange Membrane Fuel Cells						
	- Continuous Power Generation	5,00		25,0			
	- Balancing Plant	2,00		25,0			
40	Heat Pumps						
	- Heat pumps (ambient temperature)	0,68			5500		
	- Heat pumps (35 °C)	0,68			5500		
	- Absorption heat pumps (flue gas)	0,40			18500		
41	Electric Boilers						
	- 400 V; 1-3 MW	0,15				1100	0,5
	- 10 kV; 10 MW	0,08				1100	0,5
	- 10 kV; 20 MW	0,06				1100	0,5
42	Waste-to-Energy District Heating Plant	1,20				54000	5,6
43	District Heating Boiler						
	- Wood chips	0,80		5,4			
	- Wood pellets	0,40		2,7			
	- Straw	0,80		4,0			
44	District Heating Boiler - Gas Fired	0,10			3700		
45	Geothermal District Heating						
	- Absorption heat pump (70 °C)	1,80				47000	
	- Absorption heat pump (50 °C)	2,00				49000	
	- Electric heat pump	1,60				37000	
46	Solar District Heating			0,57			

2015		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
50	Pumped Hydro Storage	0,60				9000	
51	Compressed Air Energy Storage					14000	
52	Batteries						
	- Sodium Sulphur (NaS)	2,20				51000	5,3
	- 'Vanadium Redox (VRB)	1,50				54000	2,8
60	Heat Storage - Water Pits		0,7				
61	Large Scale Hot Water Tanks						
71	Underground Storage of Gas						
72	Hydrogen Storage						
80	Electrolysis						
	- Alkaline electrolysis (AEC)	1,40	4,0				
	- Solid Oxide Electrolysis (SOEC)						
	- Polymer Electrolyte Electrolysis (PEMEC)	6,00					
81	Centralised Biogas Plants						
	- Input: 300 Tons per Day	5,80		35			
	- Input: 550 Tons per Day	4,10		31			
	- Input: 800 Tons per Day	3,40		31			
	- Input: 1000 Tons per Day						
82	Upgraded Biogas						
	- Generating Capacity: 200 Nm3/h						
	- Generating Capacity: 1000 Nm3/h						
83	Biomass Gasifier, Pre-gasifier to Boilers	0,50		2,40			
84	Biomass, Gasifier, Updraft	3,70				185000	19
85	Biomass, Gasifiers, Staged Down-draft	3,55				69000	18

2020		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
01	Advanced Pulverized Fuel Power Plant						
	- Coal fired	2,03		7,0		61600	2,2
	- fired by wood pellets	2,03				61600	2,2
	- natural gas fired	1,30					
03	Rebuilding coal power plants to biomass						
	- wood pellets						
	- wood chips, straw						
	- wood chips, dried						
04	Gas Turbine Single Cycle						
	- large scale plant	0,60		3,4			
	- medium scale plant	1,20		7,0			
	- mini gasturbines						
	- micro gasturbines	0,70					
05	Gas Turbine Combined Cycle						
	- steam extraction	0,82				30000	2,5
	- back-pressure	1,45		2,5			
06	Gas Engines	1,25		9,2			
07	CO2 Capture and Storage	3,07				79500	3,75
08	Waste-to-Energy CHP Plant	8,50				16500	23
09	Biomass CHP, Steam Turbine						
	- woodchips (medium)	2,60				29000	3,9
	- woodchips (small)	3,50	3,5				
	- straw (medium)						
	- straw (small)	4,60	4,0				
10	Stirling Engines, Gasified Biomass	3,80				32000	21

2020		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
20	Wind Turbines - Onshore						
	- large	1,32		13,0			
	- medium	1,32		13,0			
	- small (> 5 kW)						
	- small (< 5 kW)						
21	Wind Turbines - Offshore	2,40		17,0			
22	Solar Photovoltaic Cells, Grid-connected	1,30					
23	Wave Power	6,40		15,0			
30	Solid Oxide Fuel Cells						
	- Continuous Power Generation	1,50		10,0			
	- Balancing Plant	0,40		10,0			
31	Proton Exchange Membrane Fuel Cells						
	- Continuous Power Generation	1,50		10,0			
	- Balancing Plant	0,40		10,0			
40	Heat Pumps						
	- Heat pumps (ambient temperature)	0,63			3650		
	- Heat pumps (35 °C)	0,63			3650		
	- Absorption heat pumps (flue gas)						
41	Electric Boilers						
	- 400 V; 1-3 MW	0,15				1100	0,5
	- 10 kV; 10 MW	0,08				1100	0,5
	- 10 kV; 20 MW	0,06				1100	0,5
42	Waste-to-Energy District Heating Plant	1,10				53000	5,4
43	District Heating Boiler						
	- Wood chips	0,80		5,4			
	- Wood pellets	0,40		2,7			
	- Straw	0,80		4,0			
44	District Heating Boiler - Gas Fired	0,10			3700		
45	Geothermal District Heating						
	- Absorption heat pump (70 °C)	1,80				47000	
	- Absorption heat pump (50 °C)	2,00				49000	
	- Electric heat pump	1,60				34000	
46	Solar District Heating			0,57			

2020		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
50	Pumped Hydro Storage	0,60				9000	
51	Compressed Air Energy Storage					14000	
52	Batteries						
	- Sodium Sulphur (NaS)	1,70				51000	5,3
	- 'Vanadium Redox (VRB)	1,10				54000	2,8
60	Heat Storage - Water Pits						
61	Large Scale Hot Water Tanks						
71	Underground Storage of Gas						
72	Hydrogen Storage						
80	Electrolysis						
	- Alkaline electrolysis (AEC)	1,00	4,0				
	- Solid Oxide Electrolysis (SOEC)	0,59			15000		
	- Polymer Electrolyte Electrolysis (PEMEC)	1,00					
81	Centralised Biogas Plants						
	- Input: 300 Tons per Day	5,40		35			
	- Input: 550 Tons per Day	3,80		31			
	- Input: 800 Tons per Day	3,20		31			
	- Input: 1000 Tons per Day						
82	Upgraded Biogas						
	- Generating Capacity: 200 Nm3/h						
	- Generating Capacity: 1000 Nm3/h						
83	Biomass Gasifier, Pre-gasifier to Boilers	0,40		2,4			
84	Biomass, Gasifier, Updraft						
85	Biomass, Gasifiers, Staged Down-draft	2,75				57000	17

2030		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
01	Advanced Pulverized Fuel Power Plant						
	- Coal fired	1,99		7,0		61600	2,2
	- fired by wood pellets	1,99				61600	2,2
	- natural gas fired	1,30					
03	Rebuilding coal power plants to biomass						
	- wood pellets						
	- wood chips, straw						
	- wood chips, dried						
04	Gas Turbine Single Cycle						
	- large scale plant	0,60		3,4			
	- medium scale plant	1,20		7,0			
	- mini gasturbines						
	- micro gasturbines	0,50					
05	Gas Turbine Combined Cycle						
	- steam extraction	0,81				30000	2,5
	- back-pressure	1,45		2,5			
06	Gas Engines	1,25		9,2			
07	CO2 Capture and Storage	3,00				79500	3,75
08	Waste-to-Energy CHP Plant	8,50				16500	23
09	Biomass CHP, Steam Turbine						
	- woodchips (medium)	2,60				29000	3,9
	- woodchips (small)	3,50	3,5				
	- straw (medium)						
	- straw (small)	4,60	4,0				
10	Stirling Engines, Gasified Biomass						

2030		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
20	Wind Turbines - Onshore						
	- large	1,29		12,0			
	- medium	1,29		12,0			
	- small (> 5 kW)						
	- small (< 5 kW)						
21	Wind Turbines - Offshore	2,30		16,0			
22	Solar Photovoltaic Cells, Grid-connected	1,10		19,0			
23	Wave Power	3,85		10,0			
30	Solid Oxide Fuel Cells						
	- Continuous Power Generation	0,80		4,0			
	- Balancing Plant	0,40		10,0			
31	Proton Exchange Membrane Fuel Cells						
	- Continuous Power Generation	0,80		4,0			
	- Balancing Plant	0,40		10,0			
40	Heat Pumps						
	- Heat pumps (ambient temperature)	0,58			3650		
	- Heat pumps (35 °C)	0,58			3650		
	- Absorption heat pumps (flue gas)						
41	Electric Boilers						
	- 400 V; 1-3 MW	0,15				1100	0,5
	- 10 kV; 10 MW	0,08				1100	0,5
	- 10 kV; 20 MW	0,06				1100	0,5
42	Waste-to-Energy District Heating Plant	1,10				53000	5,4
43	District Heating Boiler						
	- Wood chips	0,80		5,4			
	- Wood pellets	0,40		2,7			
	- Straw	0,80		4,0			
44	District Heating Boiler - Gas Fired	0,10			3700		
45	Geothermal District Heating						
	- Absorption heat pump (70 °C)	1,80				47000	
	- Absorption heat pump (50 °C)	2,00				49000	
	- Electric heat pump	1,60				34000	
46	Solar District Heating			0,57			

2030		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
50	Pumped Hydro Storage	0,60				9000	
51	Compressed Air Energy Storage					14000	
52	Batteries						
	- Sodium Sulphur (NaS)	1,70				51000	5,3
	- 'Vanadium Redox (VRB)	1,10				54000	2,8
60	Heat Storage - Water Pits						
61	Large Scale Hot Water Tanks						
71	Underground Storage of Gas						
72	Hydrogen Storage						
80	Electrolysis						
	- Alkaline electrolysis (AEC)		4,0				
	- Solid Oxide Electrolysis (SOEC)	0,59			15000		
	- Polymer Electrolyte Electrolysis (PEMEC)						
81	Centralised Biogas Plants						
	- Input: 300 Tons per Day	5,40		35,0			
	- Input: 550 Tons per Day	3,80		31,0			
	- Input: 800 Tons per Day	3,20		31,0			
	- Input: 1000 Tons per Day						
82	Upgraded Biogas						
	- Generating Capacity: 200 Nm3/h						
	- Generating Capacity: 1000 Nm3/h						
83	Biomass Gasifier, Pre-gasifier to Boilers	0,30		2,40			
84	Biomass, Gasifier, Updraft						
85	Biomass, Gasifiers, Staged Down-draft	2,70				57000	17

2050		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
01	Advanced Pulverized Fuel Power Plant						
	- Coal fired	1,89		7,0		61600	2,2
	- fired by wood pellets	1,89				61600	2,2
	- natural gas fired	1,30					
03	Rebuilding coal power plants to biomass						
	- wood pellets						
	- wood chips, straw						
	- wood chips, dried						
04	Gas Turbine Single Cycle						
	- large scale plant	0,60		3,4			
	- medium scale plant	1,20		7,0			
	- mini gasturbines						
	- micro gasturbines						
05	Gas Turbine Combined Cycle						
	- steam extraction	0,79				30000	2,5
	- back-pressure			2,5			
06	Gas Engines						
07	CO2 Capture and Storage	2,86				79500	3,75
08	Waste-to-Energy CHP Plant	8,50				16500	23
09	Biomass CHP, Steam Turbine						
	- woodchips (medium)	2,60				29000	3,9
	- woodchips (small)	3,50	3,5				
	- straw (medium)						
	- straw (small)	4,60	4,0				
10	Stirling Engines, Gasified Biomass						

2050		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
20	Wind Turbines - Onshore						
	- large	1,22		12,0			
	- medium	1,22		12,0			
	- small (> 5 kW)						
	- small (< 5 kW)						
21	Wind Turbines - Offshore	2,10		15,0			
22	Solar Photovoltaic Cells, Grid-connected	0,90		13,0			
23	Wave Power	1,60		7,0			
30	Solid Oxide Fuel Cells						
	- Continuous Power Generation	0,50		3,0			
	- Balancing Plant						
31	Proton Exchange Membrane Fuel Cells						
	- Continuous Power Generation	0,50		3,0			
	- Balancing Plant						
40	Heat Pumps						
	- Heat pumps (ambient temperature)	0,53			3650		
	- Heat pumps (35 °C)	0,52			3650		
	- Absorption heat pumps (flue gas)						
41	Electric Boilers						
	- 400 V; 1-3 MW	0,15				1100	0,5
	- 10 kV; 10 MW	0,08				1100	0,5
	- 10 kV; 20 MW	0,06				1100	0,5
42	Waste-to-Energy District Heating Plant						
43	District Heating Boiler						
	- Wood chips						
	- Wood pellets						
	- Straw						
44	District Heating Boiler - Gas Fired						
45	Geothermal District Heating						
	- Absorption heat pump (70 °C)						
	- Absorption heat pump (50 °C)						
	- Electric heat pump						
46	Solar District Heating						

2050		Nominal investment	Total O&M			Fixed O&M	Variable O&M
		(M€/MW)	%	(€/MWh)	(€/MW/yr)	(€/MW/yr)	(€/MWh)
50	Pumped Hydro Storage	0,60				9000	
51	Compressed Air Energy Storage					14000	
52	Batteries - Sodium Sulphur (NaS) - 'Vanadium Redox (VRB)	1,10					
60	Heat Storage - Water Pits						
61	Large Scale Hot Water Tanks						
71	Underground Storage of Gas						
72	Hydrogen Storage						
80	Electrolysis - Alkaline electrolysis (AEC) - Solid Oxide Electrolysis (SOEC) - Polymer Electrolyte Electrolysis (PEMEC)						
81	Centralised Biogas Plants - Input: 300 Tons per Day - Input: 550 Tons per Day - Input: 800 Tons per Day - Input: 1000 Tons per Day						
82	Upgraded Biogas - Generating Capacity: 200 Nm3/h - Generating Capacity: 1000 Nm3/h						
83	Biomass Gasifier, Pre-gasifier to Boilers	0,30		2,40			
84	Biomass, Gasifier, Updraft						
85	Biomass, Gasifiers, Staged Down-draft						

3. TECHNOLOGY SHEETS

The following technologies are included in this catalogue:

Electricity generation and CHP, thermal processes	
01	Advanced pulverized fuel power plant, large-scale
03	Steam turbines, refurbishment coal-to-biomass
04	Gas turbine, single cycle
05	Gas turbine, combined cycle
06	Gas engines
07	Power plants with CO2 capture and storage
08	Waste CHP
09	Biomass CHP, medium - small
10	Stirling engine, gasified biomass
Electricity generation, non-thermal processes	
20	Wind turbines, on land
21	Wind turbines, offshore
22	Solar photovoltaics, grid connected
23	Wave power
Electricity generation, fuel cells	
30	Fuel cells, solid oxide
31	Fuel cells, proton exchange membrane
Heat generation	
40	Heat pumps
41	Electric boilers
42	Waste-to-energy district heating
43	District heating boiler, biomass
44	District heating boiler, gas
45	Geothermal heat
46	Solar district heat
Energy storage	
50	Pumped hydro storage
51	Compressed air energy storage
52	Batteries
60	Seasonal heat storage
61	Large hot-water tanks
62	Small hot-water tanks
71	Underground gas storage
72	Hydrogen storage
Energy carrier generation and conversion	
80	Electrolysis
81	Biogas, centralised
82	Biogas upgrading
83	Gasifier, biomass, pre-gasifer to power plants
84	Gasifier, biomass, up-draft
85	Gasifier, biomass, staged

The technology sheets have not all been completed equally. In some cases data are missing, which reflects that it has not been possible to identify sufficiently reliable sources for such data.

01 ADVANCED PULVERIZED FUEL POWER PLANT

Brief technology description
Large base-load units with pulverised fuel (PF) combustion and advanced (supercritical) steam data.

Supercritical steam data are above 240-260 bar and 560-570 ^{o}C. The term 'ultra-supercritical' has been used (e.g. by ref. 4) for plants with steam temperatures of approximately 580 ^{o}C and above. Advanced data (AD) goes up to 350 bar and 700 ^{o}C (ref. 3). The advanced steam cycle includes up to ten pre-heaters and double re-heating.

The AD plants obtain higher efficiencies, both the electricity efficiency in condensing mode and the total energy efficiency in backpressure mode. The higher efficiencies are obtained in full load mode as well as part load and the high efficiencies remain even after many years of operation.

The integrated coal gasification combined-cycle (IGCC) plants are a fundamentally different coal technology, expected to achieve efficiencies above 50% in demonstration projects before year 2020 (ref. 4). Data for this technology are not presented below, since the AD technology appears to have better performance data.

Input
The process is primarily based on coal, but will be applicable to other fuels such as wood pellets and natural gas.

Output
Power and possibly heat.

The auxiliary power need for a 500 MW plant is 40-45 MW, and the net electricity efficiency is thus 3.7-4.3 percentage points lower than the gross efficiency (ref. 3).

Typical capacities
AD plants are built in capacities from 400 MW to 1000 MW.

Regulation ability
Pulverized fuel power plants are able to deliver both primary load support (frequency control) and secondary load support.

The units are in general able to deliver 5% of their rated capacity as primary load support within 30 seconds at loads between 50% and 90%. This fast load control is achieved by utilizing certain water/steam buffers within the unit. The secondary load control takes over after approximately 5 minutes, when the primary load control has utilized its water/steam buffers. The secondary load control is able to sustain the 5% load rise achieved by the primary load control and even further to increase the load (if not already at maximum load) by running up the boiler load.

Negative load changes can also be achieved by by-passing steam (past the turbine) or by closure of the turbine steam valves and subsequent reduction of boiler load.

A secondary regulation ability of 4% per minute is achievable between approximately 50% and 90% load on a pulverized fuel fired unit. The unit will respond slower below 50% and above 90%, approximately at 2% per minute (ref. 5).

Advantages/disadvantages
The efficiencies are not reduced as significantly at part load compared to full load as with CC-plants.

Coal fired power plants using the advanced steam cycle possess the same fuel flexibility as the conventional boiler technology. However, AD plants have higher requirements concerning fuel quality. Inexpensive heavy fuel oil cannot be burned due to materials like vanadium, unless the steam temperature (and hence efficiency) is reduced, and biomass fuels may cause corrosion and scaling, if not handled properly.

Environment
The main ecological footprints from coal-fired AD plants are bulk waste (disposal of earth, cinder, and rejects from mining), climate change and acidification. The fly ash can be utilized 100% in cement and concrete.

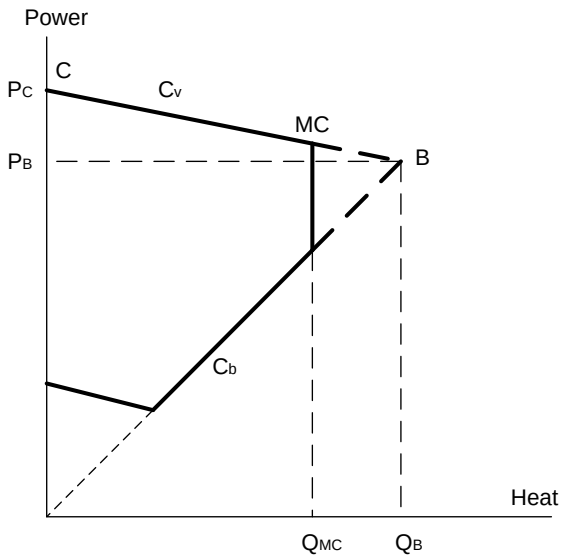
Research and development
Conventional super critical coal technology is fairly well established and so there appear to be no major breakthroughs ahead. There is very limited scope to improve the cycle thermodynamically. It is more likely that the application of new materials will allow higher efficiencies, though this is unlikely to come at a significantly lower cost (ref. 6).

Best-available-technology plants today operate at up to 600 ^{o}C. An electricity efficiency of 55 % requires steam at 700 ^{o}C and the use of nickel-based alloys (ref. 2). Further RD&D in such alloy steels is required in order to obtain increased strength, lower costs and thereby cheaper and more flexible plants.

Examples of best available technology
- Avedøre Power Station (Copenhagen), Unit 2; 570 MW; gas fired; steam at turbine inlet 580 ^{o}C and 300 bar; pre-coupled gas turbines.
- Nordjylland Power Station, Unit 3; 400 MW, commissioned 1998, coal fired.
- Skærbæk Power Station, Unit 3; 400 MW, gas fired; commissioned 1997.

Additional remarks
The efficiencies shown in the tables below assume the availability of sufficient cooling water at low temperatures (North European oceans).

A steam extraction turbine enables a large degree of freedom in varying the electricity and heat generation. This is shown by the below (ideal) figure:



P_C: Power capacity in full condensation mode; point C. No heat production.
$\eta_{e,c}$: Electricity efficiency in full condensation mode.
Q_B: Heat capacity in full back-pressure mode (no low-pressure condensation); point B.
P_B: Power capacity in full back-pressure mode.
Q_{MC}: Heat capacity at minimum low-pressure condensation; point MC.
c_v: Loss of electricity generation per unit of heat generated at fixed fuel input; assumed constant.
c_b: Back-pressure coefficient (electricity divided by heat); assumed constant.

The fuel consumption H for any given combination of power generation (P) and heat generation (Q):

$$H = \frac{P + c_v \cdot Q}{\eta_{e,c}}$$

At point MC the efficiencies can be determined by:

$\eta_{e,MC}$: Electricity efficiency at minimum low-pressure condensation:

$$\eta_{e,MC} = \eta_{e,c} \cdot \left\{1 - \frac{c_v}{c_b + c_v} \cdot \frac{Q_{MC}}{Q_B}\right\}$$

$\eta_{q,MC}$: Heat efficiency at minimum low-pressure condensation:

$$\eta_{q,MC} = \frac{\eta_{e,c}}{c_b + c_v} \cdot \frac{Q_{MC}}{Q_B}$$

$\eta_{tot,MC}$: Total efficiency (electricity plus heat) at minimum low-pressure condensation:

$$\eta_{tot,MC} = \eta_{e,c} \cdot \left\{1 + \frac{1 - c_v}{c_b + c_v} \cdot \frac{Q_{MC}}{Q_B}\right\}$$

In 2009, 3 out of 13 Danish extraction steam turbines had $Q_{MC}/Q_B = 1.0$, the average of all units being 0.80. This excludes a number of extraction steam turbines, which to a large extent were operated as condensation turbines, since the district heating loads were very small.

More details are given in **Annex 1**.

The biggest capital items of a coal plant are boiler, steam turbine and generator, with the boiler alone accounting for over 25% of costs. The civil works component falls around 20%, while the fuel handling is larger item than for most other technologies, except solid fuel biomass. Flue gas desulphurisation (FGD), which once accounted for some 15-20% of investment cost has fallen over time such that FGD and SCR (selective catalytic reduction of NOx) together typically account for some 10-15% of investment (ref. 6).

References

1. Elsam's and Elkraft's update of the Danish Energy Authority's technology catalogue (in Danish), 'Teknologidata for el- og varmeproduktionsanlæg', 1997.
2. Elforsk: "El från nya anläggningar", Stockholm, 2000.
3. www.ad700.dk
4. "Energy technology perspectives 2008", International Energy Agency, 2008.
5. DONG Energy, 2009.
6. "UK Electricity Generation Costs Update", Mott MacDonald, June 2010; commissioned by the Department of Energy and Climate Change, United Kingdom.

Data sheets

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)	2.04	2.03	1.99	1.89		15+16;15;15;15
Fixed O&M (€/MW/year)	57200	61600	61600	61600		15;9;9;9
Variable O&M (€/MWh)	2.0	2.2	2.2	2.2		15;9;9;9
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

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).

Technology	Steam turbine, fired by wood pellets, advanced steam process					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	250-400					
Electricity efficiency, condensation mode, net (%)	44-48	46-51	52	52-55	A	8;7;9;11
Cb coefficient (50°C/100°C)	0.75	0.84	1.01		F	
Cv coefficient (50°C/100°C)	0.15	0.15	0.15			1
Availability (%)	95	95	95		B	7
Technical lifetime (years)	40	40	40	40	E	6
Construction time (years)	4.5	4.5	4.5			2;3;3
Environment						
SO_2 (degree of desulphuring, %)	0	0	0	0		5
NO_X (g per GJ fuel)	38	35	35	35		12;5;5;5
CH4 (g per GJ fuel)	2	2	2	2		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)	2.04	2.03	1.99	1.89	G	15+16;15;15;15
Fixed O&M (€/MW/year)	57200	61600	61600	61600	G	15;9;9;9
Variable O&M (€/MWh)	2.0	2.2	2.2	2.2	G	15;9;9;9
Regulation ability						
Regulation speed (% per min.)	4	4	4			1
Minimum load (% of full load)	20	15	15	10		10+14

References:

1 Elsam, November 2003
2 Elsam's and Elkraft's update of the Danish Energy Authority's 'Teknologidata for el- og varmeproduktionsanlæg', December 1997
3 Eltra, September 2003
4 "Projected costs of generating electricity", International Energy Agency (IEA), 2005.
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 "Reference Document on Best Available Techniques for Large Combustion Plants", European Commision (Integrated Pollution Prevention Control), July 2006.
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

Notes:

A Supercritical in 2010 and ultra-supercritical from 2020.
B 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)
C Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2008 by multiplying by a factor 1.1876 for investment costs and 1.1672 for O&M costs.
D The cost excludes infrastructure, such as habour, district heating transmission, and electricity transmission. The unit cost refers to the capacity in full condensation mode.
E The lifespan is often quite long (up to 60 years). For this to happen, refurbishment is required (ref. 7).
F 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.
G Lower end of interval (2010) is ref. 16, upper end ref. 15.

Technology	Steam turbine, natural gas fired, advanced steam process					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	400					
Electricity efficiency, condensation mode, net (%)	45-48					1
Cb coefficient	0.7					1
Cv coefficient	0.17					1
Availability (%)	92					2
Technical lifetime (years)	30					2
Construction time (years)	4.5					2
Environment						
SO_2 (degree of desulphuring, %)	0	0	0	0		1
NO_X (g per GJ fuel)	60	60	60	60		2;1;1;1
CH4 (g per GJ fuel)	6	6	6	6		3;1;1;1
N2O (g per GJ fuel)	1	1	1	1		3;1;1;1
Financial data						
Nominal investment (M€/MW)	1.4	1.3	1.3	1.3	A	1
Fixed O&M (€/MW/year)	38000				B	1
Variable O&M (€/MWh)	0.82				B	1

References:

1 Danish Energy Agency and Energinet.dk, 2011

2 Elsams og Elkrafts opdatering af Energistyrelsens 'Teknologidata for el- og varmeproduktionsanlæg', 1997

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

Notes:

A Investment data are the same as in the 2010 catalogue, however updated with the same cost-ratio as for coal-fired power plants, mirroring the general surge in equipment cost 2007-2008.

B O&M data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying by a factor 1.2306.

03 REBUILDING COAL POWER PLANTS TO BIOMASS

Brief technology description
Existing coal power plants may be rebuilt for biomass combustion.

The easiest and cheapest solution is to convert some (or all) of the coal to a fuel with similar characteristics, such as wood pellets. In such cases it is possible to maintain steam data, efficiencies, c_v- and c_b-values.

Conversion to a more different fuel, such as wood chips or straw, requires major changes and is therefore more time consuming and costly.

Typical capacities
The below financial data are for power plants in the range of 200-400 MW electric capacity.

Environment
Emissions of the greenhouse gases methane (CH_4) and laughing gas (N_2O) will increase; see data below.

Examples of best available technology
The financial cost data below are derived from actual projects at Danish power plants Studstrup and Avedøre.

Data sheet

Years 2030 and 2050 have been deleted from the table, since it is believed that rebuilding power plants from coal to biomass is a temporary measure.

Technology	Rebuilding power plants from coal to biomass			
	2015	2020	Note	Ref
Energy/technical data				
Typical capacity, MW	200 - 400			
Environment				
Methane, CH4				
Pulverized coal as fuel (g/GJ)	0.6-1			1
- do -	1.5			2
Pulverized wood as fuel (g/GJ)	4 - 50			1
- do -	32			2
Straw as fuel (g/GJ)	32			2
Laughing gas, N2O				
Pulverized coal as fuel (g/GJ)	0.5 - 1.6			1
- do -	3			2
Pulverized wood as fuel (g/GJ)	1.2			1
- do -	0.6			2
Straw as fuel (g/GJ)	1.4			2
Financial data				
Nominal investment (M€ per MW converted capacity)			A	
- wood pellets	0.13-0.23			3
- wood chips, straw	0.42		B	4
- wood chips, dried	0.50-0.53		C	3

References:

1 "NonCO2 greenhouse gas emissions from boilers and industrial processes", VTT

2 "Emissionsfaktorer for miljøberegninger" (Emission coefficiencts for environmental calculations; in Danish), Eltra (Danish electricity systems operator), March 2003.

3 Danish Energy Agency and Energinet.dk, 2011. Based on a small number of recent projects in Denmark.

4 Dong Energy, 2007.

Notes:

A The investments may extend the technical lifetime of the power plant. On the other hand, the use of biomass may shorten the lifetime.

B The fuel is burned as is, without substantial pretreatment

C Wood chips are dried and milled, then fired same way as pulverized coal. The drier itself costs around 0.3 M€/MW.

D O&M may increase, e.g. due to reduced life of superheater and increased wear of deNOx unit. However, no data have been identified. As a first proxy, total O&M costs in Technology Sheet 01 may be applied.

E Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

04 GAS TURBINE SINGLE CYCLE

Brief technology description
The major components of a single-cycle (or open-cycle) gas turbine are: Industrial (also called heavy duty) or aero-derivative single-cycle gas turbine, gear (when needed), and generator. For combined heat and power production a heat recovery boiler (hot water or steam) is also needed.

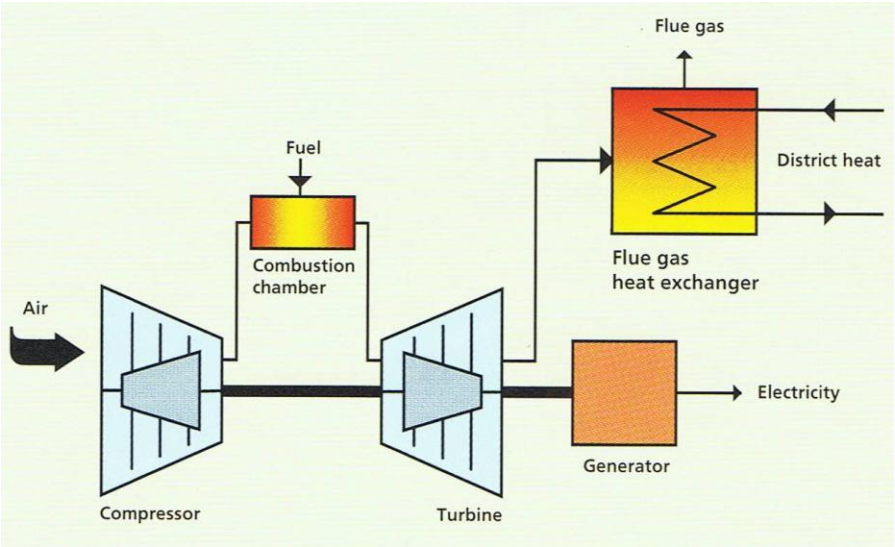


Diagramme of a plant designed for combined heat and power production.

Industrial gas turbines differ from aero-derivative turbines in that the frames, bearings, and blading is of heavier construction.

Aero-derivative turbines have generally higher efficiency than industrial ones. Industrial gas turbines have longer intervals between services compared to the aero-derivatives. However the most service-demanding module of the aero-derivative gas turbine normally can be exchanged in a couple of days thus keeping a high availability of the machine.

A few gas turbines are equipped with intercoolers and/or an integrated recuperator (preheating of combustion air) to increase efficiency - at the expense of an increased exhaust pressure loss.

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 fuel gas pressure of 20-67 bar, dependent on the gas turbine compression ratio.

Output
Electricity and heat (optional). All heat is found in the exhaust gas and is extracted by an exhaust gas boiler. Usually, emergency units do not utilize the heat.

Typical capacities
Single-cycle gas turbines are presently available in the 20 kWe - 330 MWe range (ref. 4).

The enclosed data tables cover large scale (40 – 125 MW), medium-scale (5 - 40 MW), small-scale (0.1 – 5.0 MW), and micro gas turbines (0.010 – 0.100 MW).

Regulation ability
A single-cycle gas turbine can be turned on and off within minutes, supplying power during peak demand. Because they are less efficient than combined cycle plants, they are usually used as peaking 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 (ref. 6).

Gas turbines are able to operate part load. This reduces the electrical efficiency. Normally, gas turbines with dry low NOx burners can keep emissions below 15-25 ppm in a load range of 60-100%, but at lower loads the emission will increase and can thereby limit the regulation ability.

The heat produced from the heat content of the exhaust gas can be either hot water (for heating or low-temperature process needs) or steam for process needs. Steam production is closely linked to the actual load of the turbine. Variations in steam production may be achieved by supplementary firing in the exhaust boiler.

Service contracts are usually based on generated electricity, whereby reduced generation will increase service intervals and reduce O&M costs.

To operate a gas turbine in power-only mode, the exhaust gas can be emitted directly to the atmosphere without heat extraction. Approximately 15 % of O&M costs (possibly 20 %) can be saved in power-only mode (ref. 6).

Advantages/disadvantages
For larger units, plants above 15 MW, the combined cycle technology has so far been more attractive, when used as cogeneration plants for district heating (ref. 5).

Single-cycle gas turbine plants have short start up/close down time if needed.

Construction times for gas turbine based single cycle plants are shorter than steam turbine plants.

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 the exhaust (recuperator) to achieve reasonable single-cycle electrical efficiency (25-30 %).

Research and development
Continuous research is being done concerning higher inlet temperature at first turbine blades to achieve higher electrical efficiency and output. This research is focussed on materials and/or cooling of blades, nozzles and combustors.

For several years large efforts have been made to improve the efficiency of gas turbines. The most important issue has been to increase the turbine inlet temperature (TIT). Today, the best large industrial gas turbines have TIT of approx. 1275 ^{o}C. In the near future TIT is expected to increase to almost 1400 ^{o}C for the current generation of turbines. For new generations the TIT is likely to become even higher. A higher TIT will invariably lead to a higher NOx emission. It is therefore necessary to develop new burner technologies, e.g. catalytic burners or use catalytic cleaning of the exhaust gas (ref. 5).

For 50-100 MW gas turbines, high efficiencies (above 46 %) have been reached through inter-cooling and recuperators.

Continuous development for less polluting combustion is taking place.

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

In the long perspective there are great expectations to temperature resistant ceramic materials and a new combustion technique (sequential combustion), which will allow even the small turbines to become more efficient (ref. 5).

Micro-turbines:
- Remote operation
- Low-cost recuperators
- Multi fuel availability and improved lifetime of critical components.

Additional remarks
The economic data do not include additional environmental equipment.

Low-NOx technology is assumed. Water or steam injection 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 (ref. 5).

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 the exhaust (recuperator) to achieve reasonable electricity production efficiency. If micro-turbines are installed in combination with fuel cells (hybrid cycle), an electricity efficiency of some 50-60 % may be expected. With further developments, this will increase up to 70 % according to ref. 3.

References

1. Diesel & Gas Turbine World Wide Catalogue, Brookfield US
2. Cogeneration and On-site Power Production, James and James UK
3. Opportunities for Micropower and Fuel Cell/Gas Turbine Hybrid Systems in Industrial Applications, Arthur D. Little, 2000, US
4. Gas Turbine World Handbook, 2003.
5. Danish Energy Agency: "Teknologidata for el- og varmeproduktionsanlæg", 1995.
6. Danish Gas Technology Centre, 2011.

Data sheets

Technology	Gas turbine, single cycle, large					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	**40 - 125**					
Total efficiency (%) net	80 - 85	80 - 85	80 - 85			3
Electricity efficiency (%) net	35 - 44	42 - 50	42 - 50			4;2;2
Cb ($50^oC/100^oC$)	0.84 - 1.04	0.84 - 1.3	0.84 - 1.3			2
Forced outage (%)	5	5	5			2
Planned outage (weeks per year)	3	3	3			2
Technical lifetime (years)	25	25	25			2
Construction time (years)	2	2	2			2
Environment						
SO_2 (degree of desulphuring, %)	0	0	0	0		3
NO_X (g per GJ fuel)	48	46	42	38		3
CH4 (g per GJ fuel)	1.5	1.5	1.5	1.5		3
N2O (g per GJ fuel)	1.0	1.0	1.0	1.0		3
Financial data						
Nominal investment (M€/MW)	0.4 - 0.9	0.6	0.6	0.6	A	5;1;1;1
Total O&M (€/MWh)	0.8 - 5.6	3.4	3.4	3.4	B	5;1;1;1
Regulation ability						
Fast reserve (MW per minute)	50				C	4
Minimum load (% of full load)	40 - 60%	40 - 60%	40 - 60%		D	2

References:

1 Danish Energy Agency and Energinet.dk, 2011
2 Elsam, 2003
3 Danish Gas Technology Centre, 2012
4 DONG Energy, 2009.
5 "Projected costs of generating electricity", International Energy Agency and Nuclear Energy Agency, 2010.
6 Sjællandske Kraftværker: Grovdata IRP99, November 1999. Generic data.
7 Gas Turbine World Handbook, 2003.

Notes:

A The data are valid for high-efficiency (aero-derivative) gas turbines. Investment costs of low-efficiency turbines (industrial; 32-35% electrical efficiency) are typically 0.36-0.54 M€/MW (ref. 7). Variable O&M for industrial turbines is typically 1.1-1.9 €/MWh (ref. 6).

B The O&M depends much on the gas turbine configuration, with aeroderivates being considerably more expensive than industrial turbines (ref. 4).

C The GE LMS100 can change from 50 to 100 MW in less than one minute (ref. 4).

D Technically 0%, but due to emissions 40 - 60%

Technology	Gas turbine, single cycle, medium					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	**5 - 40**					
Total efficiency (%) net	80 - 85	80 - 85	80 - 85			1
Electricity efficiency (%) net	36-40	36-42	36-45			1
Cb (50°C/100°C)	0.64-1.00	0.64 - 1.04	0.64 - 1.04			3
Availability (%)	90	90	90			2;3;3
Technical lifetime (years)	25	25	25			2;3;3
Construction time (years)	1-2	1-2	1-2			2;3;3
Environment						
SO_2 (degree of desulphuring, %)	0	0	0	0		1
NO_X (g per GJ fuel)	48	46	42	38		1
CH4 (g per GJ fuel)	1.5	1.5	1.5	1.5		1
N2O (g per GJ fuel)	1.0	1.0	1.0	1.0		1
Financial data						
Nominal investment (M€/MW)	1.2	1.2	1.2	1.2		4:5:5:5
Total O&M (€/MWh)	7	7	7	7		4:5:5:5

References:

1 Danish Gas Technology Centre, 2012
2 Elsam's and Elkraft's update of the Danish Energy Authority's 'Teknologidata for el- og varmeproduktionsanlæg', December 1997
3 Elsam, 2003
4 “Projected costs of generating electricity”, International Energy agency and Nuclear Energy Agency, 2010.
5 Danish Energy Agency and Energinet.dk, 2011

Technology	Gas turbine, single cycle, mini					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	**0.1 - 5**					
Total efficiency (%) net	80 - 85					3
Electricity efficiency (%) net	28 - 35					3
Cb (50°C/100°C)	0.55-1.1					1
Technical lifetime (years)	10					
Construction time (years)	< 0.5					
Environment						
SO_2 (degree of desulphuring, %)	0	0	0	0		2
NO_X (g per GJ fuel)	48	46	42	38		3
CH4 (g per GJ fuel)	1.5	1.5	1.5	1.5		3
N2O (g per GJ fuel)	1.0	1.0	1.0	1.0		3
Financial data						
Nominal investment (M€/MW)	1.4-2.1				A	3
Total O&M (€/MWh)	9				A	3

References:

1 Elforsk rapport nr 00:01: "El från nya anläggningar", January 2000

2 Danish Energy Agency, 2009.

3 Danish Gas Technology Centre, 2012

Notes:

A Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying by a factor 1.2306.

05 GAS TURBINE COMBINED CYCLE

More specific details on gas turbine technology are presented in technology sheet ’04 Gas Turbine Single Cycle’.

Brief technology description
Industrial or aero-derivative gas turbine, gear (if needed) and generator. Exhaust gas is led to a steam producing heat recovery boiler. The steam is used in a power producing steam turbine.

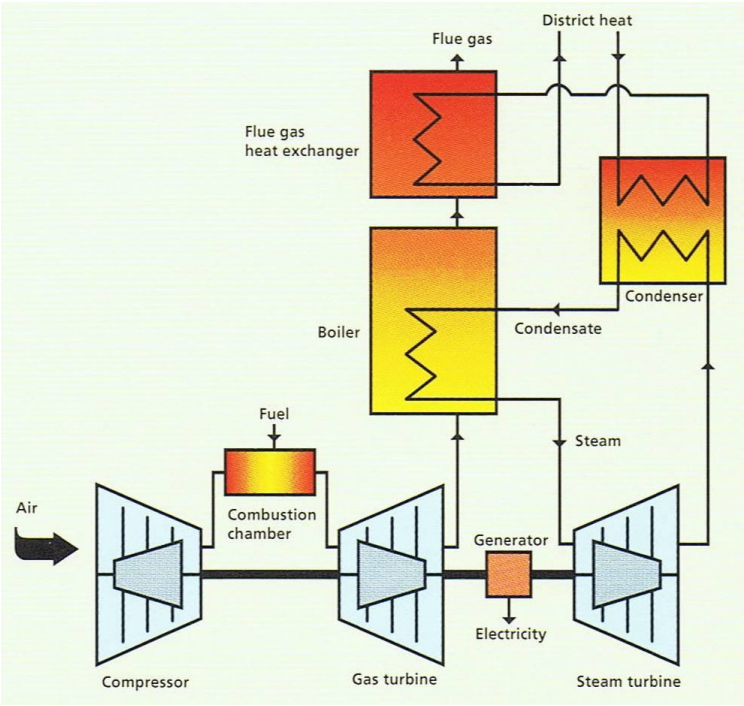


Diagramme of a plant designed for combined heat and power production.
The gas turbine and the steam turbine are shown driving a shared generator. In real plants, the two turbines might drive separate generators. Where the single shaft configuration contributes with higher reliability, the multi shaft 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 exhaust temperature, while the electricity efficiency depends, besides the technical characteristics, on the district heating forward temperature. However, some plants do not have the option to sell district heat, and the condenser is therefore cooled by sea/river/lake water.

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

The power generated by the gas turbine is typically twice 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 typically looses about 10% of its electricity generation

capacity. For example, a 40 MW gas turbine combined with a 20 MW steam turbine (condensation mode), looses 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 fuel gas pressure of 20-67 bar.

Output
Electricity and heat (for district heating or industrial processes).

Typical capacities
For combined cycle the industry has almost universally used the F class industrial machine rated at 280 MW as its workhorse. Combined with a steam turbine the block capacity is up to 440 MW (ref. 3).

The enclosed datasheets cover large scale (100 – 400 MW) and medium scale (10 – 100 MW).

Regulation ability
A combined-cycle gas turbine (CCGT) plant can be regulated up and down as one unit. If the steam turbine is out, the gas turbine can still be operating by directing the hot flue gasses through a boiler designed for high temperature or into a bypass stack.

To some extent CCGT are able to operate part load. This will reduce the electrical efficiency.

CCGT's are normally 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 more CCGT's.

Advantages/disadvantages
Smaller CCGT units have lower electrical efficiencies compared to larger units. Units below 20 MWe are seldom seen and will face close competition with single cycle gas turbines and reciprocating engines.

Natural gas fired CCGT's are characterised by low capital costs, high electricity efficiencies, short construction times and short start-up times.

The scale of economics is substantial, i.e. the specific cost of plants below 200 MWe is increasing considerably as capacity decreases. The general trend towards higher efficiencies may result in slightly higher specific costs (ref. 4).

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. However, combined cycle units are among the best technologies with regard to the electricity/heat

ratio. The somewhat lower total efficiency can therefore be excused by the extremely high electricity efficiency.

Research and development
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. catalytic burners and dry low-NOx burners.

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

Examples of best available technology
In 2009, Eon opened one of the most efficient power plants in Europe, the CHP plant Öresundsverket in Malmö, Sweden. The 440 MW CCGT has an electrical efficiency of 58 % and a total efficiency, at full cogeneration, of 90 %. The total investment figure for the project was €300 million (ref. 5).

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 around 20%, the balance of plant and electricals around 15%, the civil works around 15% and the remainder being miscellaneous other items (ref. 3).

References

1. Diesel & Gas Turbine World Wide Catalogue, Brookfield US
2. Cogeneration and On-site Power Production, James and James UK
3. “UK Electricity Generation Costs Update”, Mott MacDonald, June 2010; commissioned by the Department of Energy and Climate Change, United Kingdom.
4. Danish Energy Agency: “Teknologidata for el- og varmeproduktion”, 1995.
5. EuroHeat&Power, Vol. 6, III/2009.

Data sheets

The first data sheet (large plants) is with steam extraction steam turbines, whereas the next sheet (small and medium-size plants) is with back-pressure steam turbines, since steam extraction is often too costly for such small plants.

Technology	**Gas turbine combined cycle, steam extraction**					
	2015	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Generating capacity for one unit (MW)	**100 - 400**					
Electricity efficiency (%) net, condensation	55 - 58	58-62	59-64	59-64		1
Cv coefficient	0.13	0.13	0.13			5
Cb coefficient	1.34	1.75	1.75		A	
Availability (%)	94	94	94			2;5;5
Technical lifetime (years)	25	25	25			6
Construction time (years)	1.5 - 2	1.5 - 2	1.5 - 2	1.5 - 2		10
Environment						
NO_X (g per GJ fuel)	48	46	42	38		1
CH4 (g per GJ fuel)	1.5	1.5	1.5	1.5		4;9;9;9
N2O (g per GJ fuel)	1.0	1.0	1.0	1.0		1
Financial data						
Nominal investment (M€/MW)	0.87	0.82	0.81	0.79		10
Fixed O&M (€/MW/year)	30000	30000	30000	30000		10
Variable O&M (€/MWh)	2.5	2.5	2.5	2.5		10
Regulation ability						
Fast reserve (% per minute)	10	10	10			5

References:

1 Danish Gas Technology Centre, 2012
2 Elsam's and Elkraft's update of the Danish Energy Authority's 'Teknologidata for el- og varmeproduktionsanlæg',
3 "Projected costs of generating electricity", International Energy Agency (IEA), 2005.
4 National Environmental Research Institute, Denmark, 2009 (data from 2007).
5 Elsam, 2003
6 International Energy Agency (IEA): "Renewable Energy Costs and Benefits for Society (RECaBS)", an interactive website (http://recabs.iea-retd.org), 2007.
7 "Energy technology perspectives 2008", International Energy Agency, 2008.
8 "Energy technology perspectives 2006", International Energy Agency, 2006.
9 Own estimate by Danish Energy Agency and Energinet.dk, 2009.
10 "UK Electricity Generation Costs Update", Mott MacDonald, June 2010; commissioned by the Department of Energy and Climate Change, United Kingdom.

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.

Technology	Gas turbine combined cycle, back-pressure					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	**10 - 100**					
Total efficiency (%) net	82-89	91	91			1;4;4
Electricity efficiency (%) net	41-55	48 - 56	48 - 56		A	2
Availability (%)	94	94	94			4
Planned outage (weeks per year)	2 - 3	2 - 3	2 - 3			4
Technical lifetime (years)	25	25	25	25		5
Construction time (years)	2.5	2.5	2.5			4
Environment						
NO_X (g per GJ fuel)	48	46	42	38		2
CH4 (g per GJ fuel)	1.5	1.5	1.5	1.5		7;6;6;6
N2O (g per GJ fuel)	1.0	1.0	1.0	1.0		2
Financial data						
Nominal investment (M€/MW)	1.1-1.6	1.2-1.7	1.2-1.7		B	1
Total O&M (€/MWh)	2.5	2.5	2.5	2.5		3;1;1;1
Regulation ability						
Fast reserve (% per minute)	10	10	10			4

References:

1 Danish Energy Agency and Energinet.dk, 2011
2 Danish Gas Technology Centre, 2012
3 "Projected costs of generating electricity", International Energy Agency (IEA), 2005.
4 Elsam, 2003
5 International Energy Agency (IEA): “Renewable Energy Costs and Benefits for Society (RECaBS)”, an interactive website (http://recabs.iea-retd.org), 2007.
6 Danish Energy Agency, 2009.
7 National Environmental Research Institute, Denmark, 2009 (data from 2007).

Notes:

A 2015 values are averages developed from measured data (1994-2006) from 6 plants in operation.
B Investment data are the same as in the 2010 catalogue, however updated with the same cost-ratio as for large CCGT, mirroring the surge in equipment cost 2007-2008.

06 GAS ENGINES

Brief technology description
A gas engine drives an electricity generator, whereas engine cooling and exhaust gas can be used for heat generation, e.g. for district heating or low-pressure steam.

A gas engine drives an electricity generator, whereas engine, oil and compressor cooling and 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 exhaust gas can be cleaned and heat recovered in a condensing cooler prior to emission.

Spark ignition engines are commonly categorized according to the air/fuel-ratio:

- In stoichiometric combustion the amount of air is just sufficient for (theoretically) complete combustion. This is employed in engines with 3-way catalysts.
- Lean-burn engines have a high air/fuel-ratio. The combustion temperature and hence the NOx emission is thereby reduced. The engines are normally equipped with oxidation catalysts for CO-reduction. Engines with air/fuel ratios above 1.8 are ignited by a flame in a precombustion chamber (prechamber engines). These chambers require a gas inlet pressure of 3.5 – 4 bar.

A dual-fuel engine is a gas engine that - instead of spark plugs - uses a small amount of oil (3 – 12 %) to ignite the air-gas mix by compression (similar to the diesel engine).

Large engines can offered as combined cycle solutions, i.e. where the heat in the exhaust gas is driving a steam turbine (ref. 3).

Input
Gas, e.g. natural gas, biogas, landfill gas, and bio syngas (from thermal gasification).
Multi-fuel engines are also on the market.

In recent years, engines have been developed to use gasses with increasingly lower heating values and higher contents of impurities.

Output
Electricity and heat (district heat; low-pressure steam; industrial drying processes; absorption cooling)

Typical capacities
5 kW - 8 MW per engine.

Regulation ability
Fast start-up.
Part load possible; with slightly decreased electric efficiencies. The dual-fuel engines have the least decrease of efficiency at part load.

Gas engines have better regulation characteristics than gas turbines: They start faster (within 15 minutes), modest efficiency reduction at part load, and they can shift fuel during operation (ref. 3).

To operate an engine in power-only mode, the exhaust gas can be emitted directly to the atmosphere without heat extraction, while 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 (ref. 3).

Combined cycle units are most appropriate as base-load plants. They normally start slowly, requiring manned start-up, and thus they are not well-suited to be operated at dynamic market conditions (ref. 4).

Advantages/disadvantages
The technology has been commercial and been widely used for many years. During the years shaft efficiency has been steadily improved and emissions reduced.

Compared with gas turbines, engines cannot be used to produce considerable amounts of high-pressure steam, as most of the waste heat is released at low temperatures.

Environment
Spark ignition engines comply with national regulations within EU by using catalysts and/or lean-burn technology.

The main ecological footprint from gas engines is climate change. Gas engines usually emit 20% more CO_2-equivalents than other gas technologies, due to unburned methane in exhaust (ref. 2).

Research and development
Spark ignition engines:

- There is a need to further reduce emissions.
- Use of various gasses, or gasses with varying composition, need be investigated.
- Efficiencies can be improved by new engine designs and optimised operation.

New engine concepts:

- The homogenous compression ignition engine combines the homogenous air-fuel mix of the spark ignition engine with the compression ignition of the diesel engine.
- Applying flue gas condensation may increase the heat efficiency by 5-7%.

References
1. Danish Energy Agency, 2003.
2. ”Life cycle assessment of Danish electricity and cogeneration”, Energinet.dk, DONG Energy and Vattenfall, April 2010.
3. Danish Gas Technology Centre, 2011.
4. Danish District Heating Association, January 2012.

Data sheet

Technology	Spark ignition engine, natural gas					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	**1 - 10**					
Total efficiency (%) net	88 - 96	88 - 96	88 - 96		A	2
Electricity efficiency (%) net	40 - 48	43 - 50	45 - 53	45 - 53	H	1
Cb (50°C/100°C)	0.9					
Availability (%)	95	95	95		B	1+3
Technical lifetime (years)	20 - 25	20 - 25	20 - 25		C	1+3
Construction time (years)	< 1	< 1	< 1			1
Environment						
SO_2 (degree of desulphuring, %)	0	0	0	0		1
NO_X (g per GJ fuel)	135	60	60	60	D	1:4;4;4
CH4 (g per GJ fuel)	465	420	375	250	G	1
N2O (g per GJ fuel)	0.6	0.6	0.6	0.6		1
Financial data						
Specific investment (M€/MW)	1.0-1.5	1.0-1.5	1.0-1.5		E	5
Total O&M (€/MWh)	7.4-11	7.4-11	7.4-11			1
Regulation ability						
Fast reserve (MW per 15 minutes)	From cold to full load within 15 minutes					1
Minimum load (% of full load)	50				F	1

References:

1 Danish Gas Technology Centre (DGC), 2011.
2 Danish Association of District Heating Companies (DFF), 2003.
3 Elsam's and Elkraft's update of the Danish Energy Authority's 'Teknologidata for el- og varmeproduktionsanlæg', 1997
4 "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.
5 Danish Energy Agency, 2003

Notes:

A May be higher than 100% (flue gas condensation).
B Regular service typically every 1,000 hours. Extra service usually every 2,000, 5,000 and 10,000 hours. Major overhauls usually at 20,000 and 40,000 hours.
C Continual more rigorous environmental regulations offen shorten the practical lifetime.
D Assumed selective catalytic reduction (SCR) from 2020. This will cost about 0.05 M€/MW in investment and 0.6 €/MWh in additional O&M.
E Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying by a factor 1.2306.
F The minimum load can be lower, but this is usually not advisable due to lower efficiency
G CH4 emissions can be substantially reduced by flue gas cleaning, which is quite expensive. The stated figures assume moderat external cleaning from 2030.
H Electric efficiencies above 50 % require a combined-cycle configuration, i.e. a steam-turbine utilizing the exhaust gas heat.

07 CO_2 CAPTURE AND STORAGE

Brief technology description
In fossil fired power plants the CO_2 content in the flue gas varies between 3 and 15 per cent of total flue gas volume, depending on the type of fuel and power plant process.

CO_2 capture and storage (CCS) is best suited for large point sources of CO_2 such as power plants. The process involves three main steps:

1. Capture of CO_2.
2. Transportation to an injection sink.
3. Underground geological injection.

Several CO_2 capture systems are already available on a smaller scale, but generally they can be divided into three groups:

- Post-combustion capture
- Pre-combustion capture
- Oxy-fuel combustion

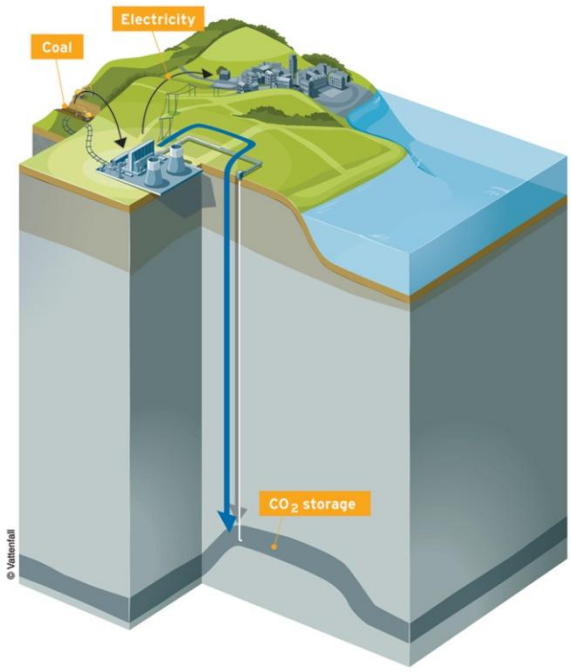


Illustration provided by Vattenfall (www.vattenfall.com).
Illustrator: www.kjell-design.com

In post-combustion capture the CO_2 is separated from the flue gas. Several technologies have been proposed. The dominant post-combustion technology is CO_2 capture by absorption in chemical solvents, like aqueous amine solutions, which is a commercial technology for some industrial purposes, but not yet for power plants. After the absorption the CO_2 is stripped from the solvent by raising the temperature, dried, compressed and transported to the storage.

Pre-combustion capture means that the CO_2 is removed prior to the actual combustion process in connection to coal gasification or decarbonisation of natural gas, which essentially produce hydrogen and CO_2. The hydrogen is then used as fuel. The removed CO_2 is compressed and transported to the storage.

In the Oxy-fuel approach the nitrogen in the air is removed prior to combustion and the fuel is combusted in an atmosphere of oxygen and recycled CO_2. The flue gas will only consist of water vapour and CO_2. The water vapour can easily be condensed giving a highly concentrated CO_2 stream, which can be compressed, purified and transported to the storage.

The major barrier for a broad use of CO_2 removal technology is the current high costs of separating and compressing the CO_2. The extra amount of energy required for this process typically reduces the overall efficiency by around 10 percentage points.

It is necessary to transport the captured CO_2 from the power plant to a location where it can be injected into a suitable (permanent) storage reservoir. This is believed to be feasible primarily by using pipelines, alternatively ships, similar to LPG tankers (ref. 1).

Relevant concepts for storage are either use of CO_2 for enhanced oil or gas recovery or storage in deep saline formations – either offshore or onshore. CO_2 is also utilised in the industry for manufacture of chemical products and in the food and drink industry, but due to the large amounts of CO_2 from power plants the only relevant utilisation is for enhanced oil or gas recovery (ref. 4).

Input
CO_2 in flue gas.

Output
Stored CO_2 and CO_2-lean flue gas.

Regulation ability
The regulation ability of a power plant is not influenced by adding post-combustion CO_2 capture. However, the CO_2 content in the flue gas decreases at part load, and thus the capture costs (in € per tonne) increases. Therefore, operating CCS power plants as base load plants may become the preferred option (ref. 4).

Research and development
Considerable research and development work is required in order to further develop and optimise techniques that reduce barriers for a wider use, i.e. to achieve greater efficiency, confidence and monitoring of storage, mitigation strategies (if there should be a leak), and integration of technologies that require scale and lower cost.

The European Commission supports RD&D on CO_2 capture and storage. The 7th Framework Programme for research, technological development and demonstration activities (2007-2013) intends to support about ten demonstration plants. The key European stakeholders formed the Zero Emission Technology Platform (ZEP, www.zeroemissionsplatform.eu) in 2005.

Examples of best available technology
Examples of best available technology for capture projects are (ref. 4):

- The Castor pilot plant at Esbjerg Power Station that cleans a 0.5% slip stream from the power plant using post combustion technology; operated by Dong Energy. The CO_2 is released after capture.
- The 30 MJ/s Oxyfuel pilotplant at Schwarze Pumpe Power Plant in Germany that demonstrates the oxyfuel technology; operated by Vattenfall.

In 2007, three large-scale storage projects (over 0.5 Mt injected per year) were in operation around the world (ref. 8):

- Offshore in Norway Statoil is injecting CO_2 from the Sleipner oil field in the Utsira aquifer. The field has a special feature as the gas has a CO_2 content of around 9%, which must be reduced to 2.5% before it is sold. The CO_2 that is stripped from the gas is injected into a structure 800 metres below the seabed is around one million tonnes of CO_2 per year. Injection began in 1996. The injection and storage is intensively monitored and provides data to various projects.
- CO_2 is extracted from natural gas from the In Salah gas field in Algeria. The CO_2 is injected into a carboniferous reservoir containing water, underlying the gas producing zone.
- CO_2 is extracted from natural gas from the Snohvit gas field in the Barents Sea, Norway. The CO_2 is injected 2600 metres underneath the gas producing zone.

Additional remarks

The costs of CCS are often divided according to the three main steps of the process:

1. Capture of CO_2, including compression for transport.
2. Transportation to an injection sink.
3. Underground geological storage.

The bulk of the costs of CCS projects are associated with CO_2 capture. For the most cost effective technologies, total capture costs (capital plus O&M costs) are USD 25 to 50 per tonne of CO_2 emissions avoided, with transport and storage about USD 10 per tonne (ref. 8). For typical European offshore settings the transport and storage cost is higher than this, and the variation from project to project is substantial (ref. 12).

Carbon capture technologies at the scale needed for power plants have not yet been demonstrated. Hence, most reported cost figures are only estimates, based on scaling up of smaller components used in other industries or on manufacturers' expert judgement based on experience from other (near-) proven technologies. The accuracy of the resulting estimates usually lies within the range of ±30 % (ref. 13).

CO_2 capture and compression consumes energy, which may result in additional emissions that must be taken into account when evaluating the impact and the cost-efficiency of CCS. The terms CO_2 capture cost and CO_2 avoidance cost are used for these two different evaluation methods.

Capture cost:	Cost of capturing one tonne of CO_2.
Avoidance cost:	Cost of reducing the CO_2 emission by one tonne, assuming same electricity generation.

For power plants, capture cost can be translated into avoidance cost based on the equation:

$$Cost(avoided) = \frac{Cost(captured) \cdot CE}{\frac{\eta_{new}}{\eta_{old}} - 1 + CE}$$

Where η_{new} and η_{old} are the electricity efficiencies of the power plants with and without CO_2 capture, and CE is the fraction that is captured. For example, if η_{new} and η_{old} are 35% and 43% and CE is 0.90, the cost ratio (avoided/captured) is 1.26.

Expressing CCS costs in terms of the cost per tonne of CO_2 avoided allows those costs to be directly compared with other CO_2 abatement measures in terms of the cost of the environmental effects that have been achieved.

As most coal-fired power plants have a long lifespan, any rapid expansion of CCS into the power sector would include retrofitting. The costs of retrofitting depend much on local circumstances:

- A case study from Norway has suggested that a retrofit would reduce efficiency by 3.3% more than a new integrated system (ref. 8). The average cost of CO_2 avoided for retrofits is about 35 % higher than for new plants. Several factors significantly affect the economics of retrofits, especially the age, smaller sizes and lower efficiencies typical of existing plants relative to new builds. The energy requirement for CO_2 capture also is usually higher because of less efficient heat integration for sorbent regeneration (ref. 10).
- A case study from Denmark indicates that retrofitting results in very little additional costs and that the electricity efficiency is only marginally lower compared with new projects (ref. 4).

There are two main methods of CO_2 transportation (ref. 14):

- Pipeline costs are roughly proportional to distance.
- Shipping costs are fairly stable over distance, but have 'step-in' costs, including a stand-alone liquefaction unit potentially remote from the power plant. The cost is less dependent on distance.

For short to medium distances and large volumes, pipelines are therefore by far the most cost-effective solution.

Pipeline costs may increase in congested and heavily populated areas by 50 to 100 % compared to a pipeline in remote areas, or when crossing mountains, natural reserves, rivers, roads, etc.; and offshore pipelines are 40 – 70 % more expensive than similar pipelines built on land (ref. 10).

References

1. Putting Carbon Back in the Ground, IEA Greenhouse Gas R&D Program, February 2001
2. CO_2 Capture and Storage in Geological Formations, by Jacek Podkanski, IEA 2003
3. CO_2 Capture at Power Stations and Other Major Point Sources, Jacek Podkanski, IEA 2003
4. Vattenfall, 2010.
5. Uncertainties in Relation to CO_2 Capture and Sequestration. Preliminary Results, Dolf Gielen, IEA/EET Working Paper 2003
6. The Future Role of CO_2 - Capture and Storage Results of the IEA-ETP Model, Dolf Gielen, 2003
7. www.ieagreen.org.uk
8. "Energy technology perspectives 2008", International Energy Agency, 2008.
9. "CO2 Capture and Storage. A key carbon abatement option", the International Energy Agency, 2008.

10. “Carbon Dioxide Capture and Storage”, International Panel on Climate Change (IPCC), 2005.
11. “Carbon Sequestration Leadership Forum Technology Roadmap” (CSLF; www.cslforum.org), 2009.
12. DONG Energy, 2009.
13. "The Cost of Carbon Capture and Storage Demonstration Projects in Europe", JRC Scientific and Technical Reports, European Commission, 2009.
14. "The Costs of CO_2 Capture, Transport and Storage", Zero Emissions Platform (ZEP), July 2011.

Data sheets

JRC (ref. 13) made a thorough review and analysis of most recent (in 2009) cost assessments of CCS. As a unique feature, all assumptions are presented in the report. All data on this page are from this report.

The mentioned reference values are calculated by a weighted average of data from 13 reviewed reports, the weighting factors determined by the robustness of the reported figures.

The following capture technologies are included:

IGCC-CCS: Integrated Gacification (of coal) Combined Cycle with pre-combustion capture
PF-CCS: Pulverized Fuel (coal) with post-combustion capture
NGCC-CCS: Natural Gas Combined Cycle with post-combustion capture
Oxyfuel: Oxyfuel combustion with post-combustion capture

		IGCC-CCS	PF-CCS	Oxyfuel	NGCC-CCS
Electricity efficiency					
Low	%	32	29	35	45
High	%	35	43	41	47
Reference value	%	35	35	35	46

All plants have a net capacity of 400 MW, and all costs are in Euro 2008:

		Carbon capture			
		IGCC-CCS	PF-CCS	Oxyfuel	NGCC-CCS
Specific investment cost					
Low	M€/MW	1.835	1.641	2.122	0.937
High	M€/MW	3.241	3.710	4.279	1.766
Reference cost	M€/MW	2.7	2.5	2.9	1.3
Fixed O&M cost					
Low	€/MW/year	60000	42000	44000	27000
High	€/MW/year	86000	80000	104000	56000
Reference cost	€/MW/year	75000	65000	90000	38000
Variable O&M cost					
Low	€/MWh	1.6	3.7	0.1	0.6
High	€/MWh	2.9	5.8	3.6	1.2
Reference cost	€/MWh	2.1	4.5	0.9	0.9
		CO2 transport and storage			
Low	€/tonnne	5			
High	€/tonnne	40			
Reference cost	€/tonnne	20			

JRC calculated the costs of CCS plants including pipelines and storage compared to reference state-of-the-art conventional plants that use the same fuel and are of the same net electricity output. The average costs per tonne of CO_2 avoided for the coal-fired CCS plants and the NGCC-CCS plant were 87 €/t and 118 €/t respectively.

The below table, in the same format as other technologies in this report, has been developed using other sources than the above-referenced JRC-report.

Technology	CO2 capture (post-combustion), pulverized coal power plant					
	2010	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	500 - 740					1+2+3+4
Capture efficiency (%)	90	90	90	90	A	1
Generation efficiency decrease (%-points)	8-10%	8-10%	8-10%	8-10%	B	1+2+3
Financial data						
Capture, post-combustion						
Nominal investment (M€/MW)	2.3-4.3	3.07	3.00	2.86	C	1+2+3+4; 2;2;2
Fixed O&M (€/MW/year)	72000-87000	72000-87000	72000-87000	72000-87000	D	1+2
Variable O&M (€/MWh)	3.4-4.1	3.4-4.1	3.4-4.1	3.4-4.1	D	1+2

References:

1 "The Costs of CO2 Capture, Transport and Storage", Zero Emissions Platform (ZEP), July 2011
2 "UK Electricity Generation Costs Update", Mott MacDonald, June 2010.
3 "Energy Technology Perspectives", IEA 2010
4 "ProjectCosts of generating Electricity", IEA & NEA, 2010

Notes:

A The non-captured CO2 is released into the atmosphere.
B Some of the electricity consumption may be regained as useful heat. The displayed efficiency decreases do most probably take the usage of heat into account.
C The nominal investment is per net generating capacity, i.e. after deducting the power consumed for CO2 capture. If you compare two power plants, with CCS (this element) and without CCS (element 01), and with the same net power generating capacity, the difference in nominal investment (e.g. 3.07-2.03 = 1.04 M€/MW in 2020) is the value of the capture equipment. If CO2 capture is added on to an existing power plant, the loss in generating capacity shall be taken into account.
D The O&M costs are per net generating capacity and net generation, i.e. after deducting the power consumer for CO2 capture.

The ZEP report (ref. 14) is probably the most complete analysis of CO_2 transport costs to date. The report describes three methods of transportation and for each of these present detailed cost elements and key cost drivers. The three methods are:

- Onshore pipeline transport
- Offshore pipeline transport
- Ship transport, including utilities.

The following table shows the unit transportation cost (EUR/tonne) for such projects, depending on transport method and distance, and with typical capacities in million tonnes per annum (Mtpa):

Typical capacity of 2.5 Mtpa, 'point-to-point' connections					
Distance	km	180	500	750	1500
Onshore pipe	€/tonne	5.4	n.a.	n.a.	n.a.
Offshore pipe	€/tonne	9.3	20.4	28.7	51.7
Ship	€/tonne	8.2	9.5	10.6	14.5
Liquafaction (for ship transport)	€/tonne	5.3	5.3	5.3	5.3
Typical capacity of 20 Mtpa, 'point-to-point' connections					
Distance	km	180	500	750	1500
Onshore pipe	€/tonne	1.5	3.7	5.3	n.a.
Offshore pipe	€/tonne	3.4	6.0	8.2	16.3
Ship (including liquefaction)	€/tonne	11.1	12.2	13.2	16.1

The ZEP report (ref. 14) also provides an update on storage costs:

Case			Cost range (€/tonne CO2 stored)		
			Low	Medium	High
Onshore	Depleted oil and gas fields	Existing well	1	3	7
Onshore	Depleted oil and gas fields	New well	1	4	10
Onshore	Saline aquifer	New well	2	5	12
Offshore	Depleted oil and gas fields	Existing well	2	6	9
Offshore	Depleted oil and gas fields	New well	3	10	14
Offshore	Saline aquifer	New well	6	14	20

08 WASTE-TO-ENERGY CHP PLANT

Brief technology description
The major components are: A waste reception area, a feeding system, a grate fired furnace interconnected with a steam boiler, a back pressure steam turbine, a generator, an extensive flue gas cleaning system and systems for handling of combustion and flue gas treatment residues.

The plant is primarily designed for incineration of municipal solid waste (MSW) and similar non-hazardous wastes from trade and industry. Some types of hazardous wastes may, however, also be incinerated.

The waste is delivered by trucks and is normally incinerated in the state in which it arrives. Only bulky items are shredded before being fed into the waste bunker.

The design and operation of MSW plants varies greatly. For example, in Sweden and Denmark, revenues gained from the combined sales of district heat and electricity enable relatively low gate fees. In other countries, support for electricity production has encouraged electrical recovery ahead of heat recovery, e.g. UK, Italy, and Spain (ref. 2).

Input
MSW and other combustible wastes, water and chemicals for flue gas treatment, gasoil or natural gas for auxiliary burners (if installed), and in some cases biomass for starting and closing down.

In Copenhagen, the heating value for MSW has increased from 9.8 MJ/kg in 2004 to 10.5 MJ/kg in 2008 and is expected to further increase to 11.5-12 MJ/kg by 2025. However, the heating value may decrease, if large amounts of combustible fractions are sorted out.

Output
Electricity and heat as hot (> 110 ^{o}C) or warm (<110 ^{o}C) water, bottom ash (slag), residues from flue gas treatment, including fly ash. If the flue gas is treated by wet methods, there may also be an output of treated or untreated process wastewater (the untreated wastewater originates from the SO_2-step, when gypsum is not produced).

Typical capacities
About 35 tonnes of waste per hour, corresponding to a thermal input of 100 - 120 MJ/s.

Regulation ability
The plants can be down regulated to about 50% of the nominal capacity, under which limit the boiler may not be capable of providing adequate steam quality and environmental performance. For emissions control reasons and due to high initial investments they should be operated as base load.

Advantages/disadvantages
By incinerating the non-recyclable, combustible waste its energy content is utilised thereby replacing equivalent quantities of energy generated on fossil fuels. Moreover, the waste is sterilised, and its volume greatly reduced. The remaining waste (bottom ash/slag) may be utilised in construction works, and it will no longer generate methane. Consequently, by incinerating the waste, the methane emission generated, when landfilling the same quantity of waste, is avoided.

The disadvantages are that a polluted, corrosive flue gas is formed, requiring extensive treatment, and that the flue gas treatment generates residues, which are classified as hazardous waste. The corrosive nature of the flue gas limits the permissible steam data to 40 - 65 bar and 400 - 425 ^{o}C and hence the electrical efficiency to around 20 - 25%.

Environment
The incineration of MSW involves the generation of climate-relevant emissions. These are mainly emissions of CO_2 as well as N_2O, NOx and NH_3. CH_4 is not generated in waste incineration during normal operation.

Waste is a mixture of CO_2 neutral biomass and products of fossil origin, such as plastics. A typical CO_2 emission factor is 37.0 kg/GJ for the waste mixture currently incinerated in Denmark.

To comply with European Union requirements (Directive 2000/76) the flue gas must be heated to min. 850 ^{o}C for min. 2 seconds and the gas must be treated for NO_x, dust (fly ash), HCl, HF, SO_2, dioxins and heavy metals. If HCl, HF and SO_2 are removed by wet processes, the wastewater must be treated to fulfil some specific water emission limit values.

The solid residues from flue gas and water treatment are hazardous wastes and are often placed in an underground storage for hazardous waste (cf. Council Decision 2003/33).

Ecological footprints are: air and water emissions including dioxins as well as solid residues to be disposed of.

Research and development
The electrical efficiency may be increased with higher steam temperature and pressure. However, this may harm the super-heater, which may be corroded by chloride and other aggressive ingredients in the flue gas, thereby decreasing the operational availability. Simple solutions, which are common in the U.S.A., are to refurbish the super-heater regularly, or to protect the super-heater with a layer of Inconell (also used on panels in the furnace). Another solution is to use a clean fuel (e.g. natural gas or self-produced gas) for heating an external super-heater.

A newly developed solution (developed by company Babcock & Wilcox Vølund) is to install a partition wall in the combustion chamber, separating the flue gas into two streams, an aggressive and a non-aggressive flow. The latter is used to heat an additional super-heater, operating at a higher temperature, thus increasing the electricity efficiency by 3-6 percentage-points.

Further challenges are the amount and quality of the residues (bottom ash, fly ash and flue gas cleaning residue).

Similarly, the amount of hazardous waste (fly ash and flue gas cleaning residue) may be reduced by optimisation of the overall process. Also, treatment of residues may be further developed for recycling and/or disposal in landfills not dedicated for hazardous waste.

Examples of best available technology
The Afval Energie Bedrijf in Amsterdam is the largest incineration plant in the world (1.5 million tonnes per year). The most recent extension (2007) involved 2 units of 34 tonnes/hour, steam data 440 ^{o}C and 130 bar, which together with steam re-heating results in an electricity efficiency of 30% (ref. 4). These units do not produce district heat, thus enabling a higher electricity efficiency than combined heat and power plants.

The most energy-efficient plant in Denmark, Reno-Nord Unit 4, was commissioned in 2005. The capacity is 20 tonnes/hour, steam data 425 ^{o}C and 50 bar. Gross electricity efficiency 26.8%, net electricity efficiency 23.2%.

Special remarks
Contrary to other fuels used for energy generation, waste has a negative price and is received at a gate fee. The primary objective of a waste-to-energy plant is the treatment of waste, energy production may be considered a useful by-product.

By condensing most of the water vapour content of the flue gas in the flue gas treatment, a thermal efficiency (based on the net calorific value) of around 100% is achievable. At the same time the plant becomes self-sufficient in water.

The following table (ref. 2) illustrates how the capital costs of a new MSW incineration plant vary with the flue-gas and residue treatment processes applied (data from Germany, 2003):

Type of flue-gas cleaning	Specific investment costs (EUR/tonne waste input/yr)			
	100 ktonnes/yr	200 ktonnes/yr	300 ktonnes/yr	600 ktonnes/yr
Dry	670	532	442	347
Dry plus wet	745	596	501	394
Dry plus wet with residue processing	902	701	587	457

References:

1. National Environmental Research Institute, Denmark, 2008.
2. 'Reference Document on the Best Available Techniques for Waste Incineration' (BREF), European Commission, August 2006.
3. IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, 2000.
4. http://www.afvalenergiebedrijf.nl/main.asp?wpl_id=55356

Data sheet

Technology	Waste to energy CHP plant					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Waste treatment capacity (tonnes/hr)	25 - 35				A	
Total efficiency (%) gross	101	100	100	100	B+C	4
Total efficiency (%) net	98	97	97	97	B+C	4
Electricity efficiency (%) gross	28	30	30	30	C	4
Electricity efficiency (%) net	24	26	26	26	C	4
Time for varm start-up (hours)	12	12	12			1
Forced outage (%)	1	1	1			1
Planned outage (weeks per year)	3	3	3			1
Technical lifetime (years)	20	20	20			1
Construction time (years)	3	3	3			1
Environment						
SO_2 (degree of desulphurisation, %)	98.2	98.4	98.4			1
NO_X (g per GJ fuel)	124	30	30	30	C+F	2;3;3;3
CH4 (g per GJ fuel)	0.59	0.59	0.59	0.59		2;4;4;4
N2O (g per GJ fuel)	1.2	1.2	1.2	1.2		2;4;4;4
Financial data						
Specific investment (M€ per tonnes/hr)	4.7-6.8	4.7-6.8	4.7-6.8	4.7-6.8	C+D+E+	4
Specific investment (M€/MW)	7 - 10	7 - 10	7 - 10	7 - 10	C+E+G	4
Total O&M (€/tonne)	53	53	53	53	H	6;4;4;4
Regulation ability						
Minimum load (% of full load)	75	75	75			1

References:

1 Rambøll Danmark, 2004
2 National Environmental Research Institute, Denmark, 2009 (data from 2007).
3 "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.
4 Danish Energy Agency and Energinet.dk, 2011.
5 Affald Danmark (association of waste management companies), 2009.
6 "BEATE. Benchmarking the waste management sector 2011" (in Danish), report delivered by waste management and industrial associations to the Danish Environment Protection Agency, 2011.

Notes:

A tph = tonnes per hour (incineration capacity).

B With flue gas condensation and without the use of cooling towers to dismiss surplus heat during the summer. In Denmark, the actual annual efficiency is around 93%.

C From 2020 application of the SCR-process (selective catalytic reduction) is assumed for NOx reduction (not a legal requirement in Denmark). This implies additional investment and O&M costs, energy use for heating the flue gas and electricity loss due to increased pressure loss. The electricity efficiency is typically reduced by about 1%, while the total efficiency is reduced by about 2.5%. These impacts are included in the forecasted values for those parameters.

D Since electricity generation is only a secondary objective of waste incineration, it may make more sense to relate the total investment to the incineration capacity, e.g. in tonnes per hour (tph), rather than the electricity generation capacity.

E Total costs are included, including the ones relating to waste treatment and heat production.

F Measured data on 8 plants in 2008 revealed Nox emissions between 80 and 180 g/GJ (ref. 5).

G Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying by a factor 1.0478.

H The quoted figure is the average total O&M for plants established in Denmark since 1999. The analysis revealed an economy-of-scale (between 50,000 and 250,000 tonnes/year): O&M (€/tonne) = 100 - 0.00025*V, where V is annually treated waste volume, in tonnes per year (ref. 6).

09 BIOMASS CHP, STEAM TURBINE, MEDIUM - SMALL

Brief technology description
The major components are: Fuel treatment and feed-in system, high-pressure steam boiler, steam turbine, generator and flue-gas heat recovery boiler (hot water or steam).

Combustion can be applied for biomass feedstock with moisture contents up to 60%.

Straw is usually delivered in 500 kg Hesston bales (15 GJ/tonnes) to the CHP plant. Compared to coal the energy density is about 9 times lower. The bales are most commonly shredded and fed by stoker screws.

Forest residues are typically delivered as wood chips. Both straw and wood residues may also be delivered as pellets.

The furnace technology can be of different nature: Grate firing, suspension firing (where the biomass is pulverized or chopped and blown into the furnace, possibly in combination with a fossil fuel), and fluidised bed. Grate combustion is very robust with regard to using varying types of biomass.

The data sheet describes plants used for combined production of electricity and district heat. These data do not apply for industrial plants, which typically deliver heat at higher temperatures than district heating plants, and therefore they have lower electricity efficiencies. Also, industrial plants are often cheaper in initial investment and O&M, among others because they are designed for shorter technical lifetimes, with less redundancy, low-cost buildings etc.

Input
Biomass; e.g. residues from wood industries, wood chips (collected in forests), peat, straw and energy crops. However, please refer to Technology sheet 01, if wood pellets are the only fuel.

Wood is usually the most favourable biomass for combustion due to its low content of ash and nitrogen. Herbaceous biomass like straw and miscanthus have higher contents of N, S, K, Cl etc. that leads to higher emissions of NOx and particulates, increased ash, corrosion and slag deposits.

The amount of biomass available for energy production varies over time. From 1997 to 2006, the Danish straw production varied between 5.2 and 6.8 million tonnes per year, while the amount used for energy varied between 1.0 and 1.5 million tonnes.

Output
Electricity and heat. The heat may come as steam or hot water.

Typical capacities
Medium: 10 – 50 MW.
Small: 1 – 10 MW.

The capacities of cogeneration plants supplying heat to district heating systems are primarily determined by the heat demands.

Regulation ability
The plants can be down regulated, but due to high initial investments they should be operated in base load.

Advantages/disadvantages
Some biomass resources, in particular straw, contain aggressive components such as chlorine. To avoid or reduce the risk of slagging and corrosion, boiler manufacturers have traditionally deterred from applying steam data to biomass-fired plants at the same level as coal-fired plants. However, recent advances in materials and boiler design constitute a breakthrough, and the newest plants have fairly high steam data and efficiencies.

In the low capacity range (less than 10 MW) the scale of economics is quite considerable.

Environment
The main ecological footprints from biomass combustion are persistent toxicity, climate change, and acidification. However, the footprints are small (ref. 1).

Research and development
Focus of the Danish R&D strategy:
- Reduce the cost of fuel, by improved pre-treatment, better characterisation and measurement methods.
- Reduce corrosion, in particular high-temperature corrosion
- Reduce slagging
- Reduced emissions
- Recycling of ashes
- Improved trouble-shooting

Examples of best available technology
- Fyn Power Plant (Denmark), Unit 8; commissioned in 2009; 35 MW electricity; 84 MJ/s district heat. 170,000 tonnes of straw per year.
- Ensted Power Plant (Denmark); commissioned 1998; separate biomass-fired boiler supplying steam in parallel with a coal-fired unit; 120,000 tonnes of straw and 30,000 tons of wood chips per year.

Additional remarks
The data sheets for small plants indicate that wood-fired plants have lower electricity efficiencies than straw-fired plants. This has no reason in technology constraints, but reflects the fact that the development of straw-fired plants has been driven by power utilities focusing on high efficiencies.

References

1. ”Life cycle assessment of Danish electricity and cogeneration”, Energinet.dk, DONG Energy and Vattenfall, April 2010.

Data sheets

Technology	Medium steam turbine, woodchips					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	10 - 50					
Electricity efficiency (%) net	29	29	29			2
Heat efficiency (%) net; without flue gas condensation	64					2
Heat efficiency (%) net; with flue gas condensation	77					2
Availability (%)	90	90	90			1
Technical lifetime (years)	30	30	30			1
Construction time (years)	4.5	4.5	4.5			1
Environment						
SO_2 (g per GJ fuel)	1.9	1.9	1.9	1.9		3;2;2;2
NO_X (g per GJ fuel)	81	81	81	81		3;2;2;2
Unburned hydrocarbon, UHC (g per GJ fuel)	6.1	6.1	6.1	6.1		3;2;2;2
N_2O (g per GJ fuel)	0.8	0.8	0.8	0.8		3;2;2;2
Financial data						
Specific investment (M€/MW)	2.6	2.6	2.6	2.6		4;2;2;2
Fixed O&M (€/MW/year)	29000	29000	29000	29000	B	1;2;2;2
Variable O&M (€/MWh)	3.9	3.9	3.9	3.9	B	1;2;2;2
Regulation ability						
Regulation speed (MW per min.)	4	4	4			1
Minimum load (% of full load)	20	20	20			1

References:

1 Energi E2, October 2004
2 Danish Energy Agency and Energinet.dk, 2011.
3 "Emisions map for combined heat and power production 2007", National Environmental Research Institute, Denmark, 2010.
4 Ramboll Denmark, 2011

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 with fluegas condensation) in full back-pressure mode of 103 %. Cf. Annex 1.

B Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying with a general inflation factor 1.2306

Technology	Small steam turbine, back-pressure, woodchips					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	**0.6 - 4.3**					
Total efficiency (%) net	103	103	103		A	1
Electricity efficiency (%) net - 100% load	25	25	25			1
Time for varm start-up (hours)	3					3
Cb (50°C/100°C)	0.3	0.3	0.3			
Availability (%)	90 -92	90 -92	90 -92			1
Technical lifetime (years)	20	20	20			4
Construction time (years)	2-3	2-3	2-3			4
Environment						
SO_2 (g per GJ fuel)	1.9	1.9	1.9	1.9		7;6;6;6
NO_X (g per GJ fuel)	81	81	81	81		7;6;6;6
Unburned hydrocarbon, UHC (g per GJ	6.1	6.1	6.1	6.1		7;6;6;6
N_2O (g per GJ fuel)	0.8	0.8	0.8	0.8		7;6;6;6
Financial data						
Nominal investment (M€/MW)	3.6-4.9	3-4	3-4	3-4	B;C	1
Total O&M (% of investment per year)	3 - 4	3 - 4	3 - 4	3 - 4		1

References:

1 Danish Energy Agency, 2010
2 Elforsk: ”El från nya anläggningar”, Stockholm, 2000.
3 Danish Technology Institute: "Udvikling af computerbaseret værktøj, energyPRO, til simulering og optimering af driftsstrategi for biobrændselsfyrede kraftvarmeværker", 2001
4 Elkraft System, October 2003 and September 2004
6 Danish Energy Agency and Energinet.dk, 2011.
7 "Emisions map for combined heat and power production 2007", National Environmental Research Institute, Denmark, 2010.

Notes:

A Flue-gas condensation
B A cost reduction of 2 % per year cost is assumed
C Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying by a factor 1.2306.

Technology	Medium steam turbine, straw					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	10 - 50					
Electricity efficiency (%) net - 100% load	29					1
Heat efficiency (%) net; without flue gas condensation	64					1
Heat efficiency (%) net; with flue gas condensation	72					1
Technical lifetime (years)	25					3
Construction time (years)						
Environment						
SO_2 (g per GJ fuel)	49	49	49	49		4;3;3;3
NO_X (g per GJ fuel)	125	125	125	125		4;3;3;3
Unburned hydrocarbon, UHC (g per GJ fuel)	0.94	0.94	0.94	0.94		4;3;3;3
N_2O (g per GJ fuel)	1.1	1.1	1.1	1.1		4;3;3;3
Financial data						
Specific investment (M€/MW)	4.0				A	1
Fixed O&M (€/MW/year)	40000				B	3
Variable O&M (€/MWh)	6.4				B	3

References:

1 Presentation on Fyn Power Plant, Unit 8 (36 MW el with flue-gas condensation) by Vattenfall , October 2006
2 "Potential contribution of bioenergy to the World's future energy demand", International Energy Agency, 2007.
3 Danish Energy Agency and Energinet.dk, 2011.
4 "Emisions map for combined heat and power production 2007", National Environmental Research Institute, Denmark, 2010.

Notes:

A 40 % has been added to the 2006 cost, due to the general price jump for steam power plants during and after the global financial crisis 2007-2009.

B O&M data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

Technology	Small steam turbine, back-pressure, straw					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	**8 - 10**					
Total efficiency (%) net	90	90	90			1
Electricity efficiency (%) net	29 - 30	29 - 30	29 - 30			1
Time for varm start-up (hours)	2					3
Availability (%)	91	91	91			2
Planned outage (weeks per year)						
Technical lifetime (years)	20	20	20			4
Construction time (years)	2 - 3	2 - 3	2 - 3			2
Environment						
SO_2 (g per GJ fuel)	49	49	49	49		6;5;5;5
NO_X (g per GJ fuel)	125	125	125	125		6;5;5;5
Unburned hydrocarbon, UHC (g per GJ fuel)	0.94	0.94	0.94	0.94		6;5;5;5
N_2O (g per GJ fuel)	1.1	1.1	1.1	1.1		6;5;5;5
Financial data						
Nominal investment (M€/MW)	4.5-5.8	4.0-5.2	4.0-5.2	4.0-5.2	A;B	1
Total O&M (% of investment per year)	4	4	4	4		1
Total O&M (€/MW/year)						

References:

1 Danish Energy Agency, 2004

2 Elsam's and Elkraft's update of the Danish Energy Authority's 'Teknologidata for el- og varmeproduktionsanlæg', 1997

3 Danish Technology Institute: "Udvikling af computerbaseret værktøj, energyPRO, til simulering og optimering af driftsstrategi for biobrændselsfyrede kraftvarmeværker", 2001

4 Elkraft System, October 2003

5 Danish Energy Agency and Energinet.dk, 2011.

6 "Emisions map for combined heat and power production 2007", National Environmental Research Institute, Denmark, 2010.

Notes:

A A cost reduction of 2 % per year cost is assumed

B 40 % has been added to the 2004 cost, due to the general price jump for steam power plants during and after the global financial crisis 2007-2009.

10 STIRLING ENGINES, GASIFIED BIOMASS

Brief technology description
A Stirling engine is driven by temperature differences created by external heating and cooling sources. One part of the engine is permanently hot, while another part of the engine is permanently cold.

The engine is filled with a working gas, typically Hydrogen or Helium, and pressurized. This working gas is moved between the hot and the cold side of the engine by a mechanical system comprising of a displacement piston coupled to a working piston. When the working gas is heated in the hot side of the engine, it expands and pushes the working piston. When the working piston moves, the displacement piston then forces the working gas to the cold side of the engine, where it cools and contracts.

In the biomass-gasifier solution developed by the company Stirling DK, the engine is Helium-filled, heated by biomass combustion flue gasses, and cooled by cooling water.

Specifically, a solid biomass fuel is converted into producer gas, which is led to one or more combustion chambers, each coupled to a Stirling engine. The gas is ignited in the combustion chamber(s), and the flue gases are heating the Stirling engine(s), which is driving an electricity generator.

For a more detailed description of the gasifier process, please refer to technology no. 84.

Input
Wood chips, industrial wood residues, demolition wood and energy crops can be used. Also, it is expected that more exotic fuel types, such as coconut shells and olive stones, can be used. Requirements to moisture content and size of the fuel are depending on the design of the gasifier.

The Stirling engines can also be fuelled by natural gas and mineral oil.

Output
Electricity and heat.

The electricity efficiency, when using wood chips, is around 18%.

Typical capacities
The electric output of one Stirling engine is 35 kW. For plants with several engines, one common gasifier is used.

Regulation ability
The heat load can be changed from 10 to 100 % and vice versa within a few minutes. The electrical output can not be regulated quickly.

Advantages/disadvantages
The main advantage of the Stirling engine is that it can generate power using residues from forestry and agriculture, which typically have a very low economic value. In addition, emission levels are very low. Finally, the service requirement of a Stirling engine is very low compared to otto- and diesel-engines.

The main disadvantage is a relatively high capital cost compared to otto- and diesel-engines.

Stirling engines are therefore ideally used for base load generation with many annual operating hours, preferable 6-8,000 hours/year.

Environment
A highly controlled gasification process together with the continuous combustion process secure much lower air emissions than otto- and diesel-engines.

Research, development and demonstration
The Danish Stirling engine updraft-gasifier technology is presently being supported in two projects:

- A multi-unit system with two engines and a wood gas boiler (for heat only) on one common updraft gasifier, is being developed, supported by PSO-means. Also a new combustion technology, high efficiency, is being developed under this program.
- A containerized plant has been built, supported by EUDP-means. In order to demonstrate fuel flexibility, the plant will be tested with 8 different fuel types. Also, an off-grid solution will be developed.

Examples of best available technology
Examples of plants in Denmark:

- In Svanholm, an 800 kJ/s updraft counter-current fixed bed gasifier was installed in 2009. The gasifier utilises wood chips and is coupled to two 35 kW Stirling engines and a 400 kJ/s wood gas boiler.
- In both Copenhagen and Lyngby, a 200 kJ/s updraft counter-current fixed bed gasifier was installed in 2009. Each gasifier utilises wood chips and is coupled to one 35 kW Stirling engine.

References

1. Biomasse kraftvarme udviklingskortlægning – Resume-rapport. Eltra. Elkraft System. Danish Energy Agency, 2003
2. Strategi for forskning, udvikling og demonstration af biomasseteknologi til el- og kraftvarmeproduktion i Danmark, Danish Energy Agency, Elkraft System og Eltra, 2003.
3. Stirling DK, December 2009.

Data sheet

Technology	Stirling engine, fired by gasified biomass					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity electric, (kW)	37	40				1
Generating capacity, heat, (kJ/s)	120	120				1
Electrical efficiency (%)	20	22			A	1
Time for wam-up (hours)	1	1				1
Forces outage (%)	4	3				1
Planned outage (weeks per year)	3	2				1
Technical lifetime (years)	15	15				1
Construction time (years)	0	0.3			B	1
Environment						
SO2 (degree of desulphuring, %)	0	0				1
NOx (ppm)	130	100				1
CH4 (ppm)	0	0				1
N20 (ppm)	0	0				1
Financial data						
Specific investment costs (M€/MW)	5.0	3.8			C+E	1
Fixed O&M (€/MW/year)	32000	32000			D+E	1
Variable O&M (€/MWh)	26	21			D+E	1

References:

1 Stirling DK, December 2009

Notes:

A The efficiency of the gasifier is 97%, while the total efficiency for the whole system is 90% (2020).

B The plants may be delivered as pre-assembled container solutions reducing construction times on site to a couple of weeks.

C Complete plant, including gasifier, combustion chambers, engines, control system, piping, and instrumentation.

D O&M for the Stirling engine itself is (2010) around 16 €/MWh, while the remianing O&M costs are for biomass feeding, gasification, heat exchangers etc.

E Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

20 WIND TURBINES ON-SHORE

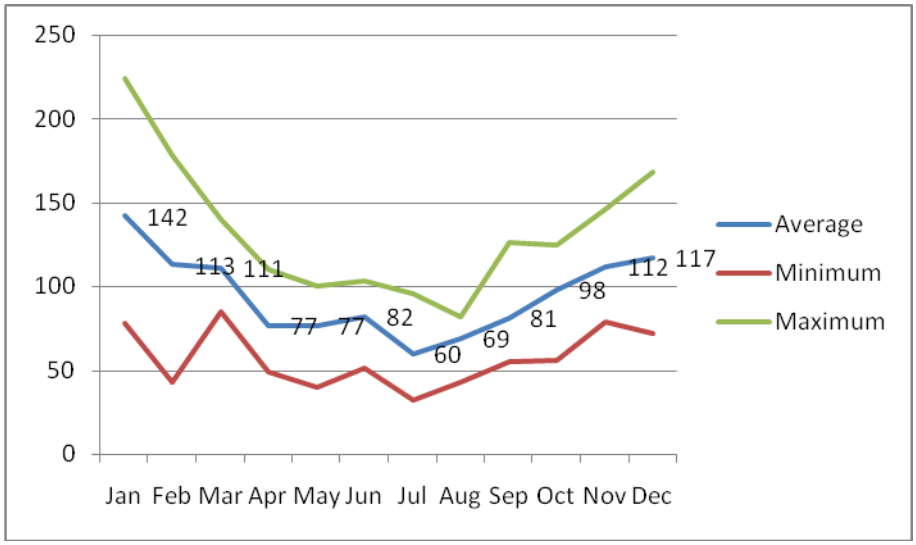
Brief technology description
Today, the most typical large wind turbine is the three-bladed propeller-type rotor on a horizontal axis, placed on the upwind side of a tubular steel tower, electricity producing and grid connected. Most often, they are pitch regulated.

In recent years gearless wind turbines with compact multi-pole permanent-magnet synchronous generators have been installed.

On-shore wind turbines are installed either as single turbines, in small clusters or in wind farms with a large number of turbines.

Input
Minimum wind speed: 3-4 m/s.
Rated power generation is reached at around 10 to 12 m/s wind speed.
Maximum operational wind speed: Approx. 25 m/s.

The seasonal variation of the energy content in winds over Denmark is shown in the below figure (ref. 4):



The blue curve (centre, with data labels) shows the average of the monthly averages over a 10-year period in per cent of annual average. The green (upper) curve shows the maximum monthly average values, while the red (lower) curve shows the minimum monthly average values.

During 2003 – 2008 the annual averages varied between 85 % and 107 % of a normal year.

Output
Electricity.

Typical capacities
Electricity generating on-shore wind turbines on-shore can typically be categorised according to nominal electrical power and application:

Large wind turbines:	800 – 4000 kW
Small wind turbines:	1 – 25 kW
Stand alone wind turbines (only few exist in DK):	5 - 500 kW
Battery chargers:	0.5 - 5 kW

For various environmental planning reasons, it is expected that that wind turbines installed on-shore in Denmark will be below 150 metres (highest point of rotor), except in remote areas and special selected test sites. This typically corresponds to a generation capacity of approx. 4 MW (ref. 10).

Regulation ability
Wind energy is a fluctuating energy source depending on the energy in the wind. Wind energy can participate in the regulation and balancing of the grid.

Advantages/disadvantages
Advantages:
- No emissions
- Stable and predictable costs; in particular due to no fuel costs and low operating costs
- Modular technology - capacity can be expanded according to demand. This saves systems overbuilds and avoids stranded debts.

Disadvantages:
- High initial investment costs
- Generation dependent of the wind (however, there is some correlation between electricity demand and wind energy generation).
- Aspects of visual impact
- Noise (in some cases)

Environment
Wind energy is a clean energy source. The main environmental concerns are visual impact, flickering (rapid shifts between shadow and light), noise and the risk of bird-collisions. Today noise is dealt with in the planning phase and normally it poses little problems to build wind turbines close to human settlements. The visual effects of wind turbine may, however, create some controversy. In general birds are able to navigate around the turbines in a wind farm and recent studies report very low bird mortality numbers in the order of 0.1 to 0.6 birds per turbine per year (ref. 9).

The energy payback time is 6 – 8 months (ref. 1 and 2).

The main ecological footprint from on-shore wind turbines is hazardous waste; i.e. from steel production and powder lacquering the tower (ref. 1 and 2).

Research and development

R&D potential:

- Reduced investment costs by improving the design methods for up-scaling and the physical models of structural design, aero-elastic and other material properties, load and safety and interactions with the energy systems
- Increased length of blades (includes aerodynamics, strength, safety and materials)
- Reduced costs of power electronics
- More efficient transmission and conversion system
- Reduced operational and maintenance costs
- Improvement of wind turbine component reliability
- Power grid integration
- Facilities for wind turbine testing, component testing, and grid connection compliance and validation testing
- More efficient methods to determine wind resources, incl. external design conditions, e.g. normal and extreme wind conditions
- Tools for wind power forecasting; incl. boundary surface meteorology
- New control elements
- Improved electrical storage techniques
- Public attitudes and visual impact

Furthermore, novel technologies may be developed and tested, such as DC generators, or superconducting generators, based on so-called high-temperature superconductor materials (operating at or above 77°K, the boiling point of Nitrogen; described in ref. 4).

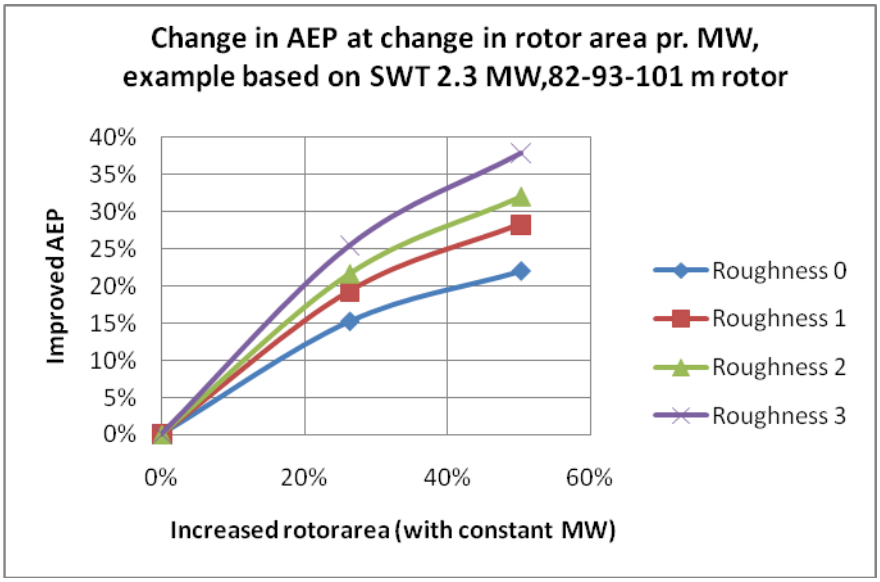
Additional remarks

The average annual capacity factor depends on the local wind resource, but also much on how the turbines are configured. Besides the hub height, an important parameter is the specific power, i.e. generator capacity divided by rotor area (W/m^2). This is illustrated in the following table, which shows the generation from two equal turbines, same rotor, but different generators:

Generator, MW	1.8	3.0
Annual generation, MWh/year	5400	6000
Average annual plant capacity factor	0.34	0.23

The larger and thus more expensive generator obviously generates more energy, but the capacity factor is less. A high capacity factor is beneficial for the overall electricity system, and may also be the most attractive solution for the wind turbine owner, depending on price mechanisms and subsidies.

The impact of specific power on the capacity factor (here annual energy production, AEP) is also illustrated below (ref. 3):



Thus, 15% more rotor area per MW yields about 12-13% more production per MW for a typical Danish site. For Danish wind turbines, the specific power has decreased substantially in recent years, from about 420 W/m^2 during 1990-2005 to about 350 W/m^2 for modern turbines (ref. 3).

The Danish average for on-shore turbines 2006-2008 (corrected to a normal wind year) was 2020 hours (ref. 12).

Turbine prices have risen about 20% from 2004 to 2007 (ref. 6). "The weakness of the dollar, rising material costs, a concerted movement towards increased manufacturer profitability, and a shortage of components and turbines continued to put upward pressure on wind turbine costs, and therefore wind power prices in 2006" (ref. 7). 2006 order books were filled up for 1.5 to 2 years ahead for all the leading suppliers (ref. 8).

Since 2001, installed wind capacity worldwide has grown by 20% to 30% a year, and the global capacity is forecasted to increase from 94 GW to 1360-2010 GW in 2050 (ref. 6). This is equivalent to an average increase of 6-8% per annum. With such increases, the future price development is much dependant on, when supply capacity will be able to balance market pull. Thus, the market imbalance (or business bubble) may for several years be more important for the price formation than technological advances.

The European Wind Energy Association (EWEA) expects that balance between demand and supply for wind turbines will be achieved around 2015 – 2018. EWEA anticipates a growth in installed capacity in EU of 2.9% per year from 2020 to 2050 (ref. 13).

Capital costs of wind energy projects are dominated by the price of the wind turbine itself. The below table shows the cost structure for a medium sized turbine (850 kW to 1500 kW), based on data from UK, Spain, Germany and Denmark (ref. 9):

	Share of total cost (%)	Share of other costs (%)
Turbine, ex works	74-82	-
Foundation	1-6	20-25
Electric installation	1-9	10-15
Grid-connection	1-9	35-45
Land	1-3	5-10
Road construction	1-5	5-10
Consultancy	1-3	5-10
Financial costs	1-5	5-10

'Ex works' means that no balance of plant, i.e. site work, foundation, or grid connection costs are included. Ex works costs include the turbine as provided by the manufacturer, including the turbine itself, blades, tower, and transport to the site.

The incremental cost of increasing the generation capacity with unchanged rotor is determined by the generator, gear, transformer and possibly grid connection. These costs constitute up to 20% of total turbine cost. Thus, doubling the generation capacity increases the total cost by approx. 20% (ref. 11).

The split of O&M costs have been studied in Germany and Denmark (ref. 9), here shown in percent of total O&M costs:

	Germany	Denmark
Land rent	18	
Insurance	13	35
Regular service	26	28
Repair and spare parts		12
Power from the grid	5	
Administration	21	11
Miscellaneous	17	14

Small wind turbines

Very small wind turbines have special features. They can roughly be classified in two categories (ref. 5):

- HAWT (Horizontal Axis Wind Turbine)
- VAWT (Vertical Axis Wind Turbine)

The traditional three blade HAWT is said to be highly dependent on "quality wind" with a minimum of turbulence and variation. The producers of VAWT claim that their turbines are less sensitive to wind

turbulence and changing wind directions. Thus, the VAWT appears most suitable for households and buildings in urban areas, while the HAWT is more appropriate for rural areas.

Noise and vibrations from building mounted turbines have yet to be solved. The Danish noise limits for micro turbines are 39 dB at a wind speed of 8 m/s and 37 dB at a wind speed of 6 m/s (ref. 5).

References

1. "Life cycle assessment of offshore and onshore sited wind power plants based on Vestas V90-3.0 MW turbines", Vestas Wind Systems, July 2006.
2. "Life cycle assessment of electricity produced from onshore sited wind power plants based on Vestas V82-1.65 MW turbines", Vestas Wind Systems, December 2006.
3. "Input data to technology catalogue for wind turbines", prepared by project 'Economy of wind turbines 2007-2009', with major Danish stakeholders as participants. P. Nielsen, EMD International, et al, October 2009.
4. www.naturlig-energi.dk
5. "Minivindmøller i København" (Mini wind turbines in Copenhagen; in Danish), Ea Energy Analysis for Copenhagen Municipality, November 2009.
6. "Energy technology perspectives 2008", International Energy Agency, 2008.
7. "Annual report on U.S. wind power installation, cost, and performance trends: 2006", US Department of Energy, May 2007.
8. "International wind energy development. World market update 2006", BTM Consult, March 2007.
9. "Contribution to the Chapter on Wind Power, Energy Technology Perspectives 2008" (cf. ref. 6), J. Lemming et al, Risø National Laboratory for Sustainable Energy, Denmark, January 2008.
10. Danish Energy Agency, 2009.
11. DONG Energy, 2009.
12. Energinet.dk, 2009.
13. "Pure power. Wind energy targets for 2020 and 2030", European Wind Energy Association (EWEA), November 2009.

Data sheets

Technology	Large wind turbines on land					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one turbine (MW)	3	3.5	3.5	3.5	A	1
Rotor diameter (m)	105 - 125	120 - 140	120 - 140	120 - 140	A	1+2
Hub height (m)	85	90	90	90	A	1
Average annual plant capacity factor	0.337	0.354	0.365	0.371	B	1
Availability (%)	97	98	98	98	C	1
Technical lifetime (years)	20	20	25	30	D	1
Construction time (years)	1.5	1.5	1.5	1.5		1
Environment						
Noise (dbA) at nearest neighbour, open land	44 (8 m/s); 42 (6 m/s)				E	1
Flicker, hours/year at nearest neighbour	< 10					1
Financial data						
Specific investment, total costs (M€/MW)	1.40	1.32	1.29	1.22	G	1
O&M (€/MWh)	14	13	12	12	C+F+G	1

References:

1 "Vindmøllers økonomi" (Economy of wind turbines), final report prepared by the project 'Economy of wind turbines 2007-2009', with major Danish stakeholders as participants. P. Nielsen, EMD International, et al, January 2010.

2 DONG Energy, December 2009.

Notes:

A The turbine size is estimated to increase further the coming 10 years, but for most sites an upper limit will be seen, partly due to air traffic, but also due to environmental impact.

B The capacity factor is quite site- and technology-specific, cf. above 'Additional remarks'. It is expected to increase further due to increased hub height and lower specific power from 2010 to 2020. After 2020 only a marginal improvement is expected through technological refinements.

C More intelligent maintenance programs and improved components are expected. These also lead to slightly improved availability.

D The life time is expected to increase with better design tools, while there no longer will be basis for repowering with larger turbines.

E Average values for Denmark 2007, 10 metres above groundlevel.

F Gearbox refurbushment is a major component of O&M costs, in particular for large turbines. Improved surveillance is expected to lower the cost. Also, gear-less turbines should reduce the cost substantially.

G Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying by a factor 1.053

Technology	Medium-size wind turbines on land					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one turbine (MW)	0.85	0.85	0.85	0.85	A	1
Rotor diameter (m)	50	50	50	50	A	1
Hub height (m)	55	55	55	55	A	1
Average annual plant capacity factor	0.303	0.318	0.329	0.334		1
Availability (%)	97	98	98	98		1
Technical lifetime (years)	20	20	25	30		1
Construction time (years)	1.5	1.5	1.5	1.5		1
Environment						
Noise (dbA) at nearest neighbour, open land	44 (8 m/s); 42 (6 m/s)					1
Flicker, hours/year at nearest neighbour	< 10					1
Financial data						
Specific investment, total costs (M€/MW)	1.40	1.32	1.29	1.22		1
O&M (€/MWh)	14	13	12	12		1

References:

1 Danish Energy Agency, November 2011

Notes:

A The maximum height is 80 m. Hence, an Environmental Impact Assessment is not required (Danish regulation). Also, noise and visual nuasance is less for neighbours.

Technology	Small wind turbines, grid-connected					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one turbine (Watt)	5000 - 30000				A	
Rotor diameter (m)	5 - 15					
Hub height (m)	25 - 35					
Utilization time (hours/year)	1500				B	2
Technical lifetime (years)	15-25				C	1
Environment						
Noise at nearest neighbour, open land						
Financial data						
Specific investment, total costs (€/Watt)	1.1-3.2				D	1
O&M (€/kWh)						

References:

1 "Catalogue of Small Wind Turbines 2009", Nordic Folkecenter for Renewable Energy, April 2009.

2 "Small wind systems. UK market report 2009", Bristish Wind Energy Association (BWEA), 2009.

Notes:

A Several small wind turbines are stand-alone DC-generating types. This data sheet covers merely AC-generating turbines.

B Estimated total installed capacity of turbines between 1.5 and 10 kW in UK 2010: 22.6 MW. Estimated annual generation: 33.65 GWh.

C Information from manufacturers

D Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying by a factor 1.053

Technology	Micro wind turbines, grid-connected					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one turbine (Watt)	200 - 5000				A	
Rotor diameter (m)	0.5 - 2.5					
Hub height (m)	1 - 25				B	
Utilization time (hours/year)	900				C	2
Annual generated electricity (kWh per m2 swept area); mean wind 6 m/s	500				D	3
Annual generated electricity (kWh per m2 swept area); mean wind 3-4 m/s	100-200				E	3
Technical lifetime (years)	15-25				F	1
Environment						
Noise at nearest neighbour, open land						
Financial data						
Specific investment, total costs (€/Watt)	2.1-7.4				G	1+4
O&M (€/kWh)	0.03				G	5

References:

1 "Catalogue of Small Wind Turbines 2009", Nordic Folkecenter for Renewable Energy, April 2009.
2 "Small wind systems. UK market report 2009", Bristish Wind Energy Association (BWEA), 2009.
3 "Mini-vindmøllers elproduktion" (Power generation from micro wind-turbines; in Danish), Risoe National Laboratory for Sustainable Energy, February 2009.
4 www.allsmallwindturbines.com
5 “Minivindmøller i København” (Mini wind turbines in Copenhagen; in Danish), Ea Energy Analysis for Copenhagen Municipality, November 2009.

Notes:

A Several small wind turbines are stand-alone DC-generating types. This data sheet covers merely AC-generating turbines.
B The smallest turbines are often mounted on roofs, with almost no tower.
C Estimated total installed capacity of turbines below 1.5 kW: 21.98 MW in UK 2010. Estimated annual generation: 19.26 GWh in 2010.
D Open agricultural land, good wind conditions; 10 metres above ground.
E Populated areas
F Information from manufacturers
G Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying by a factor 1.053

21 WIND TURBINES, OFFSHORE

More specific details on wind turbine technology are presented in technology sheet ’20 Wind Turbines On-shore’.

Brief technology description
The typical concept is a tower with a three-bladed rotor mounted on a horizontal axis. The rotor drives a gear and generator.

To minimize specific costs, offshore wind farms are typically based on large turbines in considerable numbers.

For offshore applications the electricity is usually transformed to approx. 34 kV within each turbine. The electricity from all the turbines (or a group hereof) is then collected and cabled to a transformer station, which is either offshore or on-shore.

Input
Minimum wind speed: 3-4 m/s.
Rated power generation reached at around 12 m/s wind speed.
Maximum operational wind speed: Approx. 25- 30 m/s.

Output
Electricity.

Typical capacities
The physical limit of a single wind turbine is probably well above 20 MW (with current technologies). Whether the economic optimum is reached before then is yet to be seen.

The main reason for increasing the capacity per turbine is to decrease foundation costs. However, there may be no wind resource argument to increase the height above 150-200 metres (5-10 MW), since the wind energy per m^2 may actually decrease due to a boundary layer between the upper jet winds and the lower winds.

The first offshore wind farms were established in the 1990’s, with total capacities from 2 to 17 MW. A new Danish offshore wind farm "Anholt" of 400 MW will be commissioned in 2012. The U.K. established several offshore wind farms in 2011, ranging from 30 to 175 MW.

Regulation ability
See technology sheet ’20 Wind turbines on-shore’.

Advantages/disadvantages
The case for offshore wind power is that the wind conditions generally are much better offshore than on-shore, and therefore the higher cost for offshore wind farms can be justified by a larger electricity production per installed megawatt.

The wind speeds do not increase as much with the height above sea level as they do on land. This implies that it may be economic to use lower (and thus cheaper) towers.

The wind is less turbulent at sea than over land, resulting in less mechanical fatigue.

See also ’20 Wind turbines on-shore’ for general advantages and disadvantages of wind turbines.

Environment
For offshore wind turbines some disturbance to sea-life must be anticipated during the construction phase and the operation phase.

Before, during and after the construction of two Danish wind farms Horns Reef I (160 MW) and Nysted (166 MW) comprehensive monitoring programmes were launched to investigate and document the environmental impact of these two wind farms (ref. 5). The monitoring programmes showed that, under the right conditions, even big wind farms pose low risks to birds, mammals and fish, even though there will be changes in the living conditions of some species by an increase in habitat heterogeneity. They also showed that it is possible to adapt offshore wind farms in a way which is environmentally sustainable and which causes no significant damage to the marine environment.

Research and development
Besides the R&D potential described in technology element ‘20 Wind turbines on-shore’, the following challenges need be addressed:

- Monitoring and maintenance strategies
- New foundation concepts
- Foundations for water depths beyond 15 meters
- Impacts on ocean environment

Furthermore, novel technologies may be developed and tested. Some concepts have been described in ref. 4:

- Hybrid fossil fuel/wind energy facilities on offshore oil and gas platforms.
- Hybrid wave/wind energy facilities
- Floating wind turbines. The first full-scale floating wind turbine (2.3 MW) was commissioned in the sea off Stavanger in Norway, September 2009 (ref. 3). It fell over during a hurricane December 2011.

Additional remarks
Please refer to the discussion of the average annual plant capacity factor in technology element '20 Wind turbines on-shore'.

Danish average utilization times (capacity factor multiplied by 8760 hours) for off-shore turbines 2004-2008 (corrected to a normal wind year) are shown in the below table together with values for planned sites (ref. 2 + 1):

	In operation	Planned, availability 100%
North Sea		
Horns Rev I	4110	
Rønland	4120	
Horns Rev II		4280
Ringkøbing		4300
Jammerbugt		4100
Inner seas, open sea		
Nysted/Rødsand	3620	
Samsø	3570	
Djursland		4010
Store Middelgrund		4030
Kriegers Flak		4040
Rønne Banke		4060
Inner seas, near shore		
Middelgrunden	2510	
Frederikshavn	2640	

Average investment cost structure for wind farms at Horns Reef I (160 MW; established 2002) and Nysted (166 MW; established 2003), both Denmark (ref. 4; here converted to 2011 price level):

	Investment (k€/MW)	Share (%)
Turbines ex works, incl. transport and erection	912	49
Foundations	392	21
Internal grid between turbines	95	5
Transformer station and main cable to coast	302	16
Design, project management	112	6
Environmental analysis etc.	56	3
Miscellaneous	11	<1
Total	1881	100

There is a very clear relation between foundation costs and water depth, price level 2011 (ref. 1):

Water depth (metres)	Foundation cost (M€/MW)
10	0.45
20	0.69
30	1.1
40	1.5 - 2.0

The investment cost of the transformer station depends much on, whether helicopter landing is required or not. Helicopter service is required in the North Sea, while service by ship is sufficient in most inner Danish seas. Typical investment costs in million EUR (2011) for a 200 MW wind farm are (ref. 1):

	Water depth (metres)	
	10	30-40
Helicopter landing included	30	38
Helicopter landing excluded	24	32

The landfall costs (cable to shore plus connection to grid) depends primarily on the distance. For a 200 MW wind farm, using a 132/150 kV cable, the typical cost in million EUR (price level 2011) is (ref. 1):

Distance to shore (km)	Investment cost (M€)
15	19
30	38
50	50

References

1. "Fremtidens havmølleplaceringer - 2025" ("Future locations for offshore wind parks"; in Danish), Danish Energy Agency, April 2007.
2. Energinet.dk, 2009.
3. www.statoilhydro.com, 2009.
4. “Contribution to the Chapter on Wind Power, Energy Technology Perspectives 2008” (published by the International Energy Agency), J. Lemming et al, Risø National Laboratory for Sustainable Energy, Denmark, January 2008.
5. “The Danish offshore wind farm demonstration project: Horns Rev and Nysted offshore wind farms. Review report 2005”, DONG Energy and Vattenfall, 2006.

Data sheet

The below data are based on a typical water depth (10 metres) and distance to shore (15 km) of wind farms established 2009-2011. The cost of a helicopter landing platform on the transformer station is excluded.

Technology	Offshore windturbines					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one	4 - 7	5 - 10	8 - 10	8 - 10		1+2
Rotor diameter (m)	110 - 140	130 - 160	160 - 170	160 - 200		1+2
Hub height (m)	85	95	115	130		1
Average annual plant capacity	0.457	0.479	0.502	0.514	A	1
Availability (%)	96	97	97	98		1
Technical lifetime (years)	20	20	25	30		1
Construction time (years)	3 - 4	3 - 4	3 - 4	3 - 4		1+2
Financial data						
Nominal investment, total costs (M€/MW)	3.1	2.4	2.3	2.1	B+C	1+2;1;1;1
Total O&M (€/MWh)	19	17	16	15	C	1

References:

1 "Vindmøllers økonomi" (Economy of wind turbines), final report prepared by the project 'Economy of wind turbines 2007-2009', with major Danish stakeholders as participants. P. Nielsen, EMD International, et al, January 2010.

2 DONG Energy, December 2009.

Notes:

A The capacity factor is quite site- and technology-specific, cf. above 'Special remarks'.

B The average cost of 11 offshore wind parks installed 2001- 2009 was 2.1 M€/MW (1.4 – 2.7 M€/MW), whereas the average cost of 13 planned offshore wind parks (in operation 2010 – 2013) was 3.1 M€/MW (2.3 – 3.8 M€/MW). This significant price increase has several causes, the most recognized ones being price increases in main resources, such as steel, and the fact that the current market is very much demand-driven. Also, most developers of the planned wind parks are situated on the very steep part of the learning curve. The forecasted price development presented here anticipates that the current out-of-the-ordinary situation will cease before 2020, and that the market thus will reach balance.

C Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying by a factor 1.053

For scenarios including more ambitious developments, cost data may be increased according to the tables in section ‘Additional remarks’, or you may refer to the below summary matrix in million EUR (2011) per MW:

.

		Water depth (metres)			
		10	20	30	40
Distance to shore (km)	15	0	0.24	0.64	1.28
	30	0.09	0.34	0.74	1.38
	50	0.15	0.40	0.80	1.44

Additional investment costs, relative to a location at 10 metres water, 15 km from the shore, and without helicopter landing on the transformer station.

22 PHOTOVOLTAIC CELLS, GRID-CONNECTED SYSTEMS

Brief technology description
A photovoltaic cell (PV) generates electricity, when exposed to light such as solar radiation.

PV modules can be produced from many different materials:

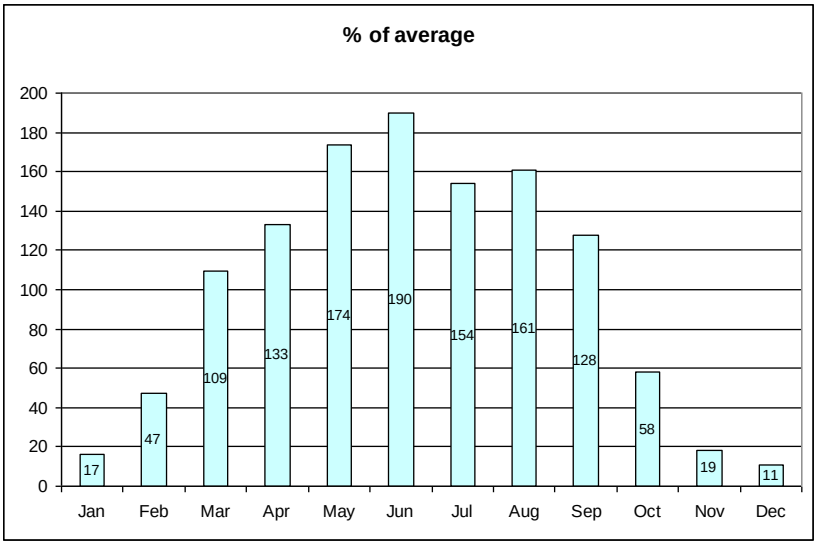
1. Crystalline silicon: The individual cells are based on mono- or poly-crystalline silicon wafers. Almost 90 % of PV systems in the world are made of crystalline silicon solar cells. This technology is expected to remain the dominating PV technology until at least 2020 (ref. 6).
2. Thin film panels: The active photovoltaic material, which is amorphous silicon, cadmium-telluride or copper-indium-selenide (CdTe, CIS or CIGS), is deposited directly on the cover or bottom glass of the solar panel in a micro-meter thin layer. Both Tandem-Junction and Triple Junction thin film modules, where several layers are deposited on top of each other in order to increase the efficiency, are already today commercial available.
3. Organic solar cells and Dye-Sensitized solar Cells (DSC): Significant research activities are currently devoted to development of cells made by organic materials or combinations of dyes and liquid electrolytes. This kind of cells are expected to develop into commercial products in the 2020-2030 timeframe (ref. 1), but are not considered viable candidates for grid-connected systems.

Other types of PV cells are found, such as special cells for concentrated sunlight or for conversion of infrared radiation from a combustion process (thermo photovoltaic)

This technology sheet deals with grid-connected systems only. The major components of such a system are PV modules, inverter, and mechanical and electrical assembly equipment.

Input
Solar radiation.

The seasonal variation of electricity generation from a typical PV system in Denmark is shown in the below figure (ref. 3):



In Denmark, about half of the electricity generated originates from diffuse radiation. This implies a fairly high degree of freedom in orienting the PV modules, both inclination and east-west (ref. 5).

Output
Direct current (DC) electricity. The DC electricity can be converted to alternating current (AC) electricity by using an inverter.

The electrical output depends on:

- Solar radiation
- Installed capacity; typically stated in W_P (p for peak power; i.e. the electrical generation capacity at Standard Test Conditions (STC), i.e. at a light intensity of 1000 W/m^2 and 25 ^{o}C cell temperature).
- Orientation of the PV panel; i.e. azimuth (angle relative to direction towards Equator) and tilt (angle relative to horizontal). In Denmark the optimum orientation is azimuth 180° and tilt 42°.
- Panel temperature (minor impact), soiling and/or shadows/shades
- Efficiency and electrical characteristic of the inverter
- Cable length and cross section, and overall quality of components

Typical capacities
PV systems are available from a few milliwatt to megawatt sizes.

Silicon solar cells are typically assembled into modules of 54-72 individual cells. The module voltage is typically 25-40 volt DC; higher voltage can be obtained by connecting more modules in series or in parallel. Most common in the market are PV modules with a capacity of 180-270 W_P, but up to 440 W_p is available.

The typical capacity for a solar roof-top system in Denmark is 4 –6 kW; equivalent to an area of 30 – 50 m^2 for crystalline silicon. A PV system with a capacity of 1 kWp will typically produce 850-900 kWh per year.

Regulation ability
PV system reflects the daylight variations. To the extent the grid peak load follows the daylight, PV systems can be – and often are, such as in California and southern Europe – used as peak shavers or as grid support at the end of feeder lines.

State of art, PV inverters only have a positive impact on power quality, as their control function is of high speed allowing them to improve local power quality. This is increasingly reflected in revised grid codes for low voltage and medium voltage grid connection. However, high penetration of PV in grids can lead to unwanted increase in voltage (ref. 9).

Advantages/disadvantages
Advantages:

- PV uses no fuel for producing the electricity.
- There is no air or other emissions from electricity generation.
- Electricity is produced in the daytime, when demand is highest.
- PV modules have a long lifetime, 30 years or more, and the modules are easily recycled.
- PV systems are easy to install and operate; no moving parts.
- PV systems integrated in buildings require no incremental ground space, and the electrical inter-connection is readably available at no or little additional cost.

Disadvantages:

- Grid-connected PV systems have high initial costs.
- The output of a PV-system is directly proportional to the solar radiation, although the efficiency decreases slightly by increasing temperature.
- Relatively high area demand per kWh produced.

Environment
Under Danish climatic conditions, the energy payback time is 1 – 4 years (ref. 5).

The main ecological footprints from silicon cells stem from the energy consumed to produce the cells (ref. 2).

The environmental impacts from silicon based PV modules are very limited, as they only contain small amounts of harmful chemicals. Other PV modules containing very small amounts of cadmium and arsenic may have environmental impact at demolition, if not carefully treated. Recycling of PV-modules is well known, although the processes are still being developed and refined, and the typical main components such as PV cells, glass and aluminium can safely be recycled.

Research and development
R&D is primarily conducted in countries, which have already implemented PV technologies in large volumes, such as Japan, USA and Germany.
The priorities in Denmark are (ref. 4):

- Silicon feedstock for high-efficiency cells
- New PV cells like photo-electro-chemical, polymer cells and nano-structured cells
- Inverters; increased technical lifetime, high efficiency and lower costs
- System technology, incl. integration in the overall electricity system
- Building integration of PV modules
- Design and aesthetics

Examples of best available technology
The Chinese company Suntech Power Co. Ltd (www.suntech-power.com) is the largest manufacturer of wafer based solar cells/modules in the world with 2010 shipments of more than 1,5 GW. The main market for Suntech Power is Germany and Italy. Manufacturing cost of about 1 €/Wp has been reported (ref. 7).

The American company First Solar (www.firstsolar.com) is the largest manufacturer of thin film solar cells in the world. In 2010 the company signed contracts to establish several 200-500 MW power plants in the USA. The company announced in 2011 that it had reduced its manufacturing cost to about 0.65 USD per watt.

Additional remarks

At present, PV modules account for roughly 60 % of total system costs, with mounting structures, inverters, cabling, etc. accounting for the rest (ref. 1).

The nominal investment cost for larger systems are typically lower than for smaller systems. Prices for systems installed in Europe 2010 were 2.7-5.9 €/W (average 4.1 €W) for systems below 10 kW and 2.4-5.4 €/W (average 3.4 €/W) for systems above 10 kW (ref. 6).

In Denmark in 2011 the PV Island Bornholm (PVIB) project installed about 350 PV roof-top systems with an aggregate capacity of about 2.1 MW at an average turn-key price including VAT of almost DKK 26/W or 3.5 €/W (ref. 8).

References

1. "Energy Technology Perspectives 2008", International Energy Agency, 2008.
2. "Life cycle assessment of Danish electricity and cogeneration", Main report October 2000 and update November 2003 (both in Danish), prepared by Danish electricity utilities. The update is based on 2001 data.
3. Energinet.dk, 2006.
4. "Solceller. Dansk strategi for forskning, udvikling, demonstation 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.
5. "Notat om solcelleteknologi" (Memo on PV technology; in Danish); memo to the Danish Climate Commission, PA Energy Ltd., 2009.
6. "Trends in photovoltaic applications. Survey report of selected IEA countries between 1992 and 2010", preliminary statistical data, IEA Photovoltaic Power Systems Programme (PVPS), 2011.
7. PV Status Report 2011, Institute of Energy, EC Joint Research Center, 2011.
8. Statistics from Oestkraft Holding A/S, analyzed by PA Energy in the PVIB Project.
9. Energinet.dk, 2011.

Data sheet:

Technology	Photovoltaic cells, large grid-connected systems on the ground					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Typical capacity for one unit (kW)	900		1300	1500		6
Module efficiency (%)						
Crystalline silicon	14-20			20-28		8;1
Thin film	8-11			22-25		1
Third generation (PEC, polymer cells)				10-40	A	1
Inverter efficiency (%)	97	98	98			2;3;3
System efficiency (%)	90% of module efficiency					3
Net electricity generation (in Denmark) per installed kW (kWh/kW)	800				B	4
Availability (%)						
Technical lifetime (years)	30	30	30	10-50	C	5;5;5;1
Inverter lifetime	10					2
Financial data						
Specific investment, total system (M€/MW)	1.5-2.5	1.3	1.1	0.9	D	10+11;3;3;9
Total O&M (€/MWh)	34		19	13	E	6+9;6;6

References:

1 “Energy technology perspectives 2008”, International Energy Agency, 2008.
2 European Commission's Energy Technology Indicators
3 Danish Energy Agency, 2011
4 ”Renewable Energy RD&D Priorities. Insights from IEA Technology Programmes”, IEA, 2006
5 International Energy Agency (IEA): “Renewable Energy Costs and Benefits for Society (RECaBS)”, an interactive website (http://recabs.iea-retd.org), 2007.
6 "A strategic research agenda for PV technology", the EU PV Technology Platform, quoted by “Notat om solcelleteknologi” (Memo on PV technology; in Danish); memo to the Danish Climate Commission, PA Energy Ltd., 2009.
7 "Renewable Energy RD&D Priorities. Insights from IEA Technology Programmes", IEA, 2006
8 PA Energy Ltd., October 2009.
9 “Energy technology perspectives 2010”, International Energy Agency, 2010.
10 "Projected costs of Generating Electricity, 2010", International Energy Agency & Nuclear Energy Agency, 2010.
11 "Large scale PV plants - Also in Denmark", PA Energy and SiCon, report to the Energy Research and Demonstration Programme (EUDP) of the Danish Energy Agency, April 2011.
12 Addendum to ref. 11, January 2012.

Notes:

A Third generation cells may include two very different conepts, ultra-high efficiency and ultra-low cost. This implies a large span in efficiencies.

B Germany 1000 kWh/kW; Italy, Spain and Portugal 1400 kWh/kW (ref. 7).

C First generation cells have very long lives (40-50 years), while younger generations have shorter lives, with ultra-low cost 3. generation cells around 10-15 years.

D Ref. 10 quotes prices of 2.2-5.0 M€/MW for plants expected to be commissioned in 2015. Ref. 12 quotes prices of 1.35-2.10 M€/MW for ground placed turnkey installations above 200 kW, based on 5 actual tenders. The very low prices end 2011 (ref. 12) was partly due to a substantial excess production capacity compared with market demand. On this background, the data from these two sources have here been aggregated to 1.5-2.5 M€/MW. The inverter typically constitutes about 15% of total investment cost.

E The O&M costs are primarily due to reinvestments or repair of inverters, secondarily to periodic overhauls.

23 WAVE ENERGY

Brief technology description
A wave power converter comprises a structure interacting with the incoming waves. The wave power is converted by a Power Take-off (PTO) system based on hydraulic, mechanical or pneumatic principles driving a rotating electrical generator producing electricity or by a linear generator directly driven by the structure.

Numerous concepts are under development. Most of them can be classified according to three categories (ref. 2):

A. A *point absorber* is a floating device, moved up and down by the waves, typically anchored to the sea floor.
B. A *terminator* is a structure located perpendicular to the wave movement, 'swallowing' the waves
C. An *attenuator* is placed in the wave direction, activated by the passing waves.

There is no commercially leading technology on wave power conversion at the present time. However a few different systems are presently at a stage of being developed at sea for prototype testing or developed at a more fundamental level including tank testing, design studies and optimisation.

Input
Energy in ocean waves.

The energy content along Europe's Atlantic coasts is typically 40-70 kW/m. The wave influx in the Danish part of the North Sea is 24 kW/m farthest West, 7 kW/m nearer the coast, in average about 15 kW/m. The inner seas are irrelevant with only 1 kW/m (ref. 2).

The annual variation is normally within +/- 25%, while the seasonal variation is around 5:1, with highest potential during winter (ref. 2).

Output
Electricity.
Some systems are designed to pump water and produce potable water.

Typical capacities
The electrical output from wave power converters in some cases are generated by electrical connected groups of smaller generator units of 100 – 500 kW, in other cases several mechanical or hydraulically interconnected modules supply a single larger turbine-generator unit of 1 – 3 MW. These sizes are for pilot and demonstration projects. Commercial wave power plants will comprise a large number of devices, as is the case with offshore wind farms.

Regulation ability
The ability to regulate the system operation depends on the design of the PTO system. In general the systems are developed with the aim of regulating the system to absorb most of the incoming waves at a given time, but also to enable disconnection of the system from the grid if required for safety or other reasons.

Wave power is more predictable compared to wind power and the waves will continue some time after the wind has stopped blowing. This could help increase the value of systems with combined wind and wave power.

Advantages/disadvantages
Advantages:

- Wave power converters produce power without the use of fossil fuels.
- The power plants are located in the ocean without much visual intrusion.
- Wave power is a more predictable resource compared to wind.
- Extracting energy from waves can help costal protection, as the wave heights are reduced

Disadvantages:

- The initial prototype development at sea is costly and the successful development to reach costs comparable with i.e. off shore wind will require dedicated development programmes and substituted electricity prices until the technology has matured.
- In Denmark, the largest wave energy resource is found 150 km from the shore, making grid connection only feasible for large wave energy farms.
- Wave power converters, albeit at sea, take up large amounts of space, much dependent on type of converter and how much power is extracted. It is too early to tell, whether wave power will require more or less space than offshore wind power (ref. 7).

Environmental aspects
As for wind-energy a positive life cycle impact is expected. Planned in cooperation with navigation, oil exploitation, wind farms and fishing industry wave power plants are expected to have a positive impact on the living conditions for fish in the sea, by providing sheltered areas.

Research and development
The most recent Danish R&D strategy (ref. 3) has three focus areas:

- Continue the development and demonstration of concepts that have already proven a technical and economical potential.
- Support R&D in new concepts with promising perspectives.
- Evaluate most feasible sites, assess ways of safe anchoring, and determine how wave energy is best integrated into the Danish electricity system.

Examples of best available technology
It is too early to define best available technologies, since numerous technologies are being tested and demonstrated. Recent reviews have identified about 100 projects at various stages of development, and the number does not seem to be decreasing. Most concepts are described in ref. 5. This includes the

most mature Danish technologies: Wave Star, Wave Dragon, Poseidon Floating Power Plant, Waveplane, Dexa.

By 2009, several plants with an individual turbine/generator capacity of up to 0.7 MW have been demonstrated (ref. 6).

Scotland and Portugal are very active in developing wave energy. Portugal had a goal of having 23 MW capacity installed by end of 2009. The first plant consisted of 3 Pelamis wave devices (www.pelamiswave.com), each 750 kW, installed in 2008 (ref. 1 and 2). However, due to financial problems for one of the investors, the plant was not in continuous operation end of 2009 (ref. 4).

National targets in Europe (ref. 9):

United Kingdom:	0.3 GW in 2020
Ireland:	0.5 GW in 2020
France:	0.3 GW in 2015
Spain:	0.2 GW in 2015
Portugal:	0.3 GW in 2020

Additional remarks

A cost breakdown of a typical mature ocean energy project is as follows (ref. 1):

Site preparation:	12%
Civil works:	55%
Mechanical and electrical equipment:	21%
Electrical transmission:	5%
Contingencies:	7%

Such a breakdown depends much on the chosen system and ocean location i.e. water depth and distance to shore. Energinet.dk has developed a spreadsheet to estimate the cost of energy (ref. 8).

References

1 "Energy Technology Perspectives 2008", International Energy Agency, 2008.
2. "Ressourceopgørelse for bølgekraft i Danmark" (Wave energy resources in Denmark), Aalborg University for the Danish Commission on Climate Change Policy, May 2009.
3. "Bølgekraftteknologi. Strategi for forskning og udvikling" (Wave power technologies. Strategy for R&D; in Danish); Danish Energy Agency and Energinet.dk, June 2005.
4. Aalborg University, Department of Civil Engineering, November 2009.
5. International Energy Agency Implementing Agreement on Ocean Energy Systems (IEA-OES; www.iea-oceans.org), Annual Report 2008.
6. "State of the art analysis", status report of the Waveplam project, February 2009. www.waveplam.eu/files/downloads/SoA.pdf
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8. www.energinet.dk/DA/KLIMA-OG-MILJOE/Energi-og-klima/Forskning-i-vedvarende-energi/Sider/Boelgekraft.aspx

9. www.eu-oea.com/euoea/files/ccLibraryFiles/Filename/000000001047/Cover%20letter%20position%20paper_merged.pdf

Data sheet

	Wave Power					
	2015	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Generating capacity for one power plant (MW)	1.0 - 30	2.0 - 50	10 - 100	50 - 500		1;1;4;4
Length of installation of one power plant km	0.2 - 2	0.2 - 5.0	1 - 20	5 - 100		1;1;4;4
Annual generated electricity production (MWh/MW)	1500	2500	3500	4500		4
Availability (%)	90	95	97	98		4
Technical lifetime (years)	10	20	25	30		4
Construction time	3 - 4	3 - 4	3 - 4	3 - 4	C	4
Financial data						
Nominal investment (M€/MW)	4.6-11	3.8-9.0	2.2-4.5	1,6	A+B	2;2;2;3
O&M (€/MWh)	20	15	10	7		4
O&M (€/kW/year)	85			47		3

References:

1 Wave Net final report, Project no. ERK5 – CT –1999-20001 (2000 - 2003)
2 "Energy Technology Perspectives 2008", International Energy Agency, 2008.
3 "Energy Technology Perspectives 2010", International Energy Agency, 2010.
4 Danish Wave Energy Association, 2012

Notes:

A The cost presented provides an estimate for what capital cost and operating costs of wave power converters might be in the future assuming all R&D challenges have been overcome, that economics of scale have been realized and that efficiencies in production and operation due to the learning curve effect have been achieved.

B Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

C Much dependent on plant size and location.

30 SOLID OXIDE FUEL CELLS

Brief technology description
The solid oxide fuel cell (SOFC) is an electrochemical cell that converts hydrogen and oxygen into electricity, heat and water. When the heat is recuperated, the fuel cell work in a Combined Heat and Power (CHP) mode, otherwise it is a Power generator only.

The Solid Oxide Fuel Cell (SOFC) is a high-temperature fuel cell (600-800°C) and the exhaust gas can be used to drive gas or steam turbines in combined cycle mode. Electricity efficiency of a single cycle SOFC-plant in the range 1-200 kW can be approximately 60%[1], when fuelled with natural gas at atmospheric pressure. The systems may achieve overall efficiencies up to 88 % (ref. 5) or beyond, if low temperature heat can be utilized. Some vendors expect electrical efficiencies of 70-75 %, when combining with gas turbines.

SOFCs are particularly appropriate for stationary applications. Here, large fuel cell generators are described. Differentiation is made between CHP for continuous power delivery, which requires long life time, and plants for providing balancing power in shorter periods, requiring shorter lifetime.

Input
Natural gas, methane, methanol, hydrogen and similar fuels can be used. Hydrogen may originate from electrolysis (e.g. based on renewable electricity) or waste from the chemical industry.

Units fuelled by methane gas will include a reformer. Hydrogen units will need an electrolyser and hydrogen storage for local production.

Output
Electricity (DC) and heat.
If AC is needed, a DC/AC inverter is required.

Typical capacities
The typical capacities can range from 10 kW to multi megawatt of electricity and from 10 kW to megawatt of heat.

Regulation ability
It is expected, that SOFC fuel cells will have good part load capabilities between 100 - 20 % load.

To guarantee optimal running high temperature fuel cells need to be kept at working temperature, requiring sufficient insulation or additional energy during the idle running phases.

[1] ESTO report expects 45-47% electrical efficiency and 80-85% overall efficiency of a similar system (ref. 2). Also other sources of information predicts electricity efficiencies around 50 % or higher for natural gas fuelled SOFC-systems (ref. 4, 5)

Advantages/disadvantages
One advantage is high electrical efficiency also at reduced load. This can be beneficial for a liberalised and volatile energy market, since the need for regulation of decentralised power plants may increase. Furthermore, the total waste heat is made available in a flexible way at high temperatures. This means that the waste heat can be utilised in combined cycle plants, not just for district heating.

A disadvantage is the long start up time needed to heat up the fuel cell from cold-state (4-6 hours).

Environment
Due to higher efficiencies, absence of open flame as well as other features, fuel cells are less polluting per kWh electricity than conventional and other competing CHP technologies. There is no emission of sulphur containing compounds and soot. NOx levels are also very modest.

If a fossil fuel is used as fuel for a SOFC system, CO_2 will be emitted, albeit less than for alternative technologies.

Research and development
The fuel cell technology has proven higher electrical efficiency than competing power generating technologies. However, the fuel cell technology still has to mature with regards to issues such as life time and cost reduction. It is expected that the Danish fuel cell technology matures to reach a commercial level within this decade.

In Denmark a document has defined the Overall Strategy for Development of Fuel Cell Technology (ref. 4). Among other conclusions it states that fuel cell systems have potential interest for society based on environmental-, economical-, energy-, and system considerations. However, a considerable R&D effort is needed primarily to reduce costs of fuel cells, stacks, and systems, and to ensure high efficiency and long durability.

There is focus on development of cells and cell-stacks for different purposes. Currently work is progressing on two types of SOFCs:

- Anode supported cells optimized for operation at 700-800°C (2nd generation)
- Metal-supported cells optimized for operation at approximately 600°C (3rd generation)

Examples of best available technology
At H.C. Ørsted power plant a 10 kW SOFC demonstration has been deployed during 2009 operating at natural gas. The stack technology was delivered by Topsoe Fuel Cell and the manufacture of the unit was made by EBZ GmbH.

Bloom Energy (USA) has delivered several 100 kW Bloom Box power plants in the US based on SOFC technology.

Additional remarks
As SOFC is a new technology which is not yet fully developed it is difficult to get reliable estimates for the future.

References

1: Siemens AG; www.energy.siemens.com/hq/en/power-generation/fuel-cells/; 2009.

2: Fuel Cells – Impact and consequences of fuel cells technology on sustainable development. t. Fleischer and D. Oertel. An ESTO Project Report prepared for Prospective Technology Studies Joint Research Centre by Institut für Technikfolgenabschätzung und Systemanalyse (ITAS), March 2003.

3: Topsoe Fuel Cell, October 2009.

4: ”Overordnet strategi for udvikling af brændselscelle teknologi i Danmark” (Overall Strategy for Development of Fuel Cell Technology, in Danish). Eltra, Elkraft System, and Danish Energy Agency, 2003.

5: Solid Oxide Fuel Cells - Assessment of Technology from an Industrial Perspective. Pålsson et. al. Haldor Topsøe A/S Lyngby, Denmark, May 2003.

Data sheets

Technology	Solid Oxide Fuel Cell (SOFC) Continuous power generation, fuelled by natural gas at atmospheric pressure					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	0.1	1	10	100		1
Total efficiency (%) net	90	92	95	97	A	1
Electricity efficiency (%) net, full load 25% load	50 45	55 50	60 52	63 55	A	1
Working temperature (oC)	750	750	650	650		1
Technical lifetime, power (years)	6	15	20	20		1
Environment (fuel: natural gas)						
SO_2 (mg per kWh)	0	0	0	0		1+2
NO_X (kg per GJ fuel)	0.0001	0.0001	0.0001	0.0001	B	1+2
CH_4 (mg per kWh)	negligible	negligible	negligible	negligible		1+2
CO (kg per GJ fuel)	< 0.003	< 0.003	< 0.003	< 0.003	B	1+2
NMVOC (mg per kWh)	negligible	negligible	negligible	negligible		1+2
Financial data						
Investment (M€/MWel)	5.0	1.5	0.8	0.5	C	1
Total O&M (€/MWh)	25	10	4	3	D	1

References:

1 Danish Power Systems, Dantherm Power, H2logic Aps., IRD A/S, Serenergy A/S. & Topsoe Fuel Cell A/S, 2011.

2 Fuel Cells – Impact and consequences of fuel cells technology on sustainable development. T. Fleischer and D. Oertel. An ESTO Project Report prepared for Prospective Technology Studies Joint Research Centre by Institut für Technikfolgenabschätzung und Systemanalyse (ITAS). March 2003".

Notes:

A Based on lower heating value.

B Hydrogen produced by electrolysis and fuel cells operated on pure hydrogen have none of the listed emissions.

C Including fuel processing e.g. methane reformer or electrolyser, but no building included.

D Service and maintenance e.g. change of filters, fuel cell stacks.

Technology	Solid Oxide Fuel Cell (SOFC) Balancing plant, fuelled by natural gas at atmospheric pressure					
	2015	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Generating capacity for one unit (MW)	0.1	0.5	0.5		A	1
Total efficiency (%) net	90	92	92		B+C	1
Electricity efficiency (%) net	> 52.5	> 55	> 55		B+C	1
Working temperature (oC)	750	650	650		B+C	1
Maximum time for cold start-up (hours)	6	4	4			1
Start-up time, when warm (seconds)	90	90	90		D	
Technical lifetime, power (years)	3	5	5			1
Construction time (years)	1	1	1			3
Environment (fuel: natural gas)						
SO_2 (mg per kWh)	0	0	0			1
NO_X (kg per GJ fuel)	0.0001	0.0001	0.0001		E	1
CH_4 (mg per kWh)	negligible	negligible	negligible			1
CO (kg per GJ fuel)	< 0.003	< 0.003	< 0.003		E	1
NMVOC (mg per kWh)	negligible	negligible	negligible			1
Financial data						
Investment (M€/MWel)	2.0	0.4	0.4		C+F	1
Total O&M (€/MWh)	25	10	10		G	1

References:

1 Danish Power Systems, Dantherm Power, H2logic Aps., IRD A/S, Serenergy A/S. & Topsoe Fuel Cell A/S, 2011.

2 Siemens AG; www.energy.siemens.com/hq/en/power-generation/fuel-cells/; 2009.

3 Danish Gas Technology Centre, 2011

Notes:

A Scalable units stated is minimum output.

B Based on lower heating value.

C Electrolyser and hydrogen storage not included.

D From 20% load to 100% load.

E The listed emissions are related to reformed methane fuelled units, hydrogen fuelled units does not have any emissions

F Depends on economics of scale – includes DC/AC grid connection and heat grid connection

G Service and maintenance e.g. change of filters, fuel cell stacks

31 PROTON EXCHANGE MEMBRANE FUEL CELLS

Brief technology description
In a Proton Exchange – or Polymer Electrolyte - Membrane Fuel Cell (PEM FC) an electrochemical conversion of hydrogen into electricity and heat takes place. It is a relatively low temperature fuel cell, which can change load very fast. It consists of a thin polymer membrane, which allows penetration of hydrogen ions.

PEM FC is the fuel cell technology, which is most developed so far, and it is currently available on the market up to 250 kW.

In Denmark, the following main types are being developed:

- Low temperature (LT PEM), conventional water cooled; by University of South Denmark, IRD Fuel Cells and Dantherm Power.
- Medium temperature (MT PEM); by IRD Fuel Cells.
- High temperature (HT PEM); by Danish Power Systems (DPS), Technical University of Denmark, IRD Fuel Cells, Dantherm Power and Serenergy.
- Direct methanol fuel cells (DMFC); by IRD Fuel Cells, University of Southern Denmark and Technical University of Denmark.

LT PEMs operate from subzero up to 80°C and are sensitive to carbon monoxide in the fuel gas. A variant of the LT PEM can operate directly on diluted methanol. MT PEMs operate from subzero to around 120ºC and are less sensitive to fuel impurities than LT PEM. HT PEMs operates from ≈120ºC up till 200°C, and can work with several percentages of carbon monoxide in the fuel gas. PEM FCs working at 150-200°C can be run with hydrogen from the reformer/shift unit (reforms natural gas or liquid fuels to hydrogen), which is not purified. Efficiency of the HT PEMs is not yet on the level of the best LT PEMs, but the potential is there (ref. 1).

In this section, large fuel cell generators are described. Differentiation is made between CHP for continuous power delivery, which requires long life time, and plants for providing balancing power in shorter periods, requiring shorter lifetime.

Input
Hydrogen for LT/MT/HT PEM, methanol for DMFC.
If another hydrogen carrying agent such as methane is used, it needs to be reformed into hydrogen in an external reformer. This is where HT PEM offers more simple system architecture.

Output
Electricity (DC) and heat.
If AC is needed, a DC/AC inverter is required.

Typical capacities
The typical capacities can range from 1 to 200 kW (ref. 1).

Regulation ability
The LT PEM has a very short start-up time and PEM FC in general enables fast regulation of load due to the relatively low operating temperature. However, if a reformer is part of the system, the regulation is slower.

Environment
Primarily due to the higher efficiencies and lower temperatures than normal combustion, fuel cells are expected to be less polluting per kWh than conventional technologies (except for NMVOC – non-methane volatile organic compounds). Also, fuel cell systems might be developed as CHP-plants in small scale (micro - for individual homes) with relatively high efficiencies. That may enlarge the market and application of micro scale CHP and thus increase the overall efficiency of the electricity and heat systems.

However, if a fossil fuel is reformed to hydrogen, the emissions from reforming must be taken into account. Emissions of CO_2 will per energy unit of fossil fuel be the same from fuel cells as that of a conventional technology, but if storage of CO_2 will be an option, extraction of CO_2 from a fuel cell system is expected to be advantageous compared to conventional technology. It implies that a comprehensive infrastructure system is constructed to handle the CO_2. A substantial CO_2 saving is achieved in most applications due to the high efficiencies.

Advantages/disadvantages
PEM FC can be used for mobile applications (battery chargers for remote power supply in leisure, military and marine) as well as stationary applications (power back up for Telecom, combined heat and power supply for housing applications, balancing the grid etc.). Several large car companies all over the world are undertaking research to develop the technology (ref. 2).

LT PEM only operates on very clean hydrogen; the content of CO must be below 50-100 ppm (ref. 1). HT PEM is more tolerant and can accept 1% CO or more (ref. 6).

Research and development
In Denmark an Overall Strategy for Development of Fuel Cell Technology was recently issued by the stakeholders of "The Danish Partnership for hydrogen and Fuel Cells" (ref. 3). Among other conclusions it states that fuel cell systems have potential of interest for society on the grounds of environmental-, economical-, energy-, and system considerations. However, a considerable R&D effort is needed primarily to reduce costs of fuel cells, stacks, and systems, and to ensure high efficiency and long durability.

In the Sevens Framework Programme of EU fuel cells are included in the Research activities having an impact in the medium and the longer term. A Joint Technological Initiative (JTI) for Fuel Cells and Hydrogen Joint Undertaking (FCH JU) has been established in 2008. The FCH-JU is a unique public private partnership supporting research, technological development and demonstration (RTD) activities in fuel cell and hydrogen energy technologies in Europe. Its aim is to accelerate the market introduction

of these technologies, realizing their potential as an instrument in achieving a carbon-clean energy system. The European Commission will contribute with up to 470 M€ for the 6-year period until 2013 (ref. 4).

Examples of best available technology

A 10 kW hydrogen-fuelled power plant was demonstrated by Norwegian Hydro at the island Utsira (Norway) in the period 2004-2007. The generator was delivered by IRD A/S and based on their LT PEM technology.

H2 Logic in 2010 installed a complete hydrogen production and fuel cell combined heat and power plant for storage of renewable energy in Greenland. The plant has a production capacity of 19 Nm^3 H_2/hour and a fuel cell power on 20 kW (ref. 7).

Dantherm Power has in 2009 delivered a 100 kW unit to BC Hydro in Canada operating on hydrogen made from electrolysis on a remote location in British Colombia. The installation produces hydrogen at night and electricity during day time in order to match supply for a hydropower plant and demand from a small community. In 2011 Dantherm Power has shipped 5 hydrogen fuelled system of 45 to 50 kW to South Africa and Korea,

Ballard (Canada) is delivering a 1 MW unit to Toyota Motor Sales in California, USA. Hydrogen is produced by steam-reformation of renewable bio-gas generated from landfill gas. The unit will be in operation in 2012. Earlier Ballard in 2010 commissioned a similar system at First Energy Corp. in Ohio USA for grid balancing. Ballard has delivered a number of smaller systems ranging from 163 kW an up in size.

Nedstack (Netherlands) have in 2011 constructed a 1 MW PEM fuel cell generator to be operated on waste hydrogen from Solvays chlor-alkali plant in Lillo, near Antwerp, Belgium (ref. 8).

Additional remarks

As fuel cells are a new technology, which is not yet fully developed, it is difficult to get reliable estimates for the future. Furthermore the technology is not being sold on the open market and prices are not readily available.

There is no international norm on how to define the efficiency of a fuel cell. This should be taken into account when comparing efficiencies from different references.

References

1. IRD A/S, November 2009.
2. Fuel Cells – Impact and consequences of fuel cells technology on sustainable development. t. Fleischer and D. Oertel. An ESTO Project Report prepared for Prospective Technology Studies Joint Research Centre by Institut für Technikfolgenabschätzung und Systemanalyse (ITAS). March 2003
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5. Dantherm Power, 2009.

6. Q. Li, R. He, J. Gao, J. O. Jensen and N. J. Bjerrum: "The CO poisoning effect in polymer electrolyte membrane fuel cells operational at temperatures up to 200°C". J. Electrochem. Soc. 150 (12), A1599-A1605 (2003)
7. www.h2logic.com/com/news/H2KT_info-sheet-ENG.pdf
8. www.nedstack.com/applications/demonstration-systems

Data sheets

Technology	**Proton Exchange Membrane Fuel Cell (PEMFC) Continuous power generation, fuelled by natural gas**					
	2015	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Generating capacity for one unit (MW)	0.1	1	10	100		1
Total efficiency (%) net	90	92	95	97	A	1
Electricity efficiency (%) net, full load 25% load	50 45	55 50	60 52	63 55	A	1
Working temperature (oC)	70	80	80 - 100	100 - 180		1
Technical lifetime, power (years)	6	15	20	20		1
Environment (fuel: natural gas)						
SO_2 (mg per kWh)	0	0	0	0		1+2
NO_X (kg per GJ fuel)	0.0001	0.0001	0.0001	0.0001	B	1+2
CH_4 (mg per kWh)	negligible	negligible	negligible	negligible		1+2
CO (kg per GJ fuel)	< 0.003	< 0.003	< 0.003	< 0.003	B	1+2
NMVOC (mg per kWh)	negligible	negligible	negligible	negligible		1+2
Financial data						
Investment (M€/MWel)	5.0	1.5	0.8	0.5	C	1
Total O&M (€/MWh)	25	10	4	3	D	1

References:

1 Danish Power Systems, Dantherm Power, H2logic Aps., IRD A/S, Serenergy A/S. & Topsoe Fuel Cell A/S, 2011.
2 Fuel Cells – Impact and consequences of fuel cells technology on sustainable development. T. Fleischer and D. Oertel. An ESTO Project Report prepared for Prospective Technology Studies Joint Research Centre by Institut für Technikfolgenabschätzung und Systemanalyse (ITAS). March 2003".

Notes:

A Based on lower heating value.
B Hydrogen produced by electrolysis and fuel cells operated on pure hydrogen have none of the listed emissions.
C Including fuel processing e.g. methane reformer or electrolyser, but no building included.
D Service and maintenance e.g. change of filters, fuel cell stacks.

Technology	Proton Exchange Membrane Fuel Cell (PEMFC) Balancing plant, fuelled by natural gas					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	0.1	0.5	0.5		A	1
Total efficiency (%) net	85	92	92		B+C	1
Electricity efficiency (%) net	> 50	> 55	> 55		B+C	1
Working temperature (oC)	70	80	80		B+C	1
Start-up time, when warm (seconds)	60	60	60		D	1
Technical lifetime, power (years)	3	5	5			1
Construction time (years)	1	1	1			3
Environment (fuel: natural gas)						
SO_2 (mg per kWh)	0	0	0			1
NO_X (kg per GJ fuel)	0.0001	0.0001	0.0001		E	1
CH_4 (mg per kWh)	negligible	negligible	negligible			1
CO (kg per GJ fuel)	< 0.003	< 0.003	< 0.003		E	1
NMVOC (mg per kWh)	negligible	negligible	negligible			1
Financial data						
Investment (M€/MWel)	2.0	0.4	0.4		C+F	1
Total O&M (€/MWh)	25	10	10		G	1

References:

1 Danish Power Systems, Dantherm Power, H2logic Aps., IRD A/S, Serenergy A/S. & Topsoe Fuel Cell A/S, 2011.

2 Siemens AG; www.energy.siemens.com/hq/en/power-generation/fuel-cells/; 2009.

3 Danish Gas Technology Centre, 2011

Notes:

A Scalable units stated is minimum output.

B Based on lower heating value.

C Electrolyser and hydrogen storage not included.

D From 20% load to 100% load.

E The listed emissions are related to reformed methane fuelled units, hydrogen fuelled units does not have any emissions

F Depends on economics of scale – includes DC/AC grid connection and heat grid connection

G Service and maintenance e.g. change of filters, fuel cell stacks

40 HEAT PUMPS

Brief description
Heat pumps employ the same technology as refrigerators, moving heat from a low-temperature location to a warmer location. Heat pumps usually draw heat from the ambient (input heat) and convert the heat to a higher temperature (output heat) through a closed process; either compressor heat pumps (using electricity) or absorption heat pumps (using heat; e.g. steam, hot water or flue gas).

Heat pumps serve different purposes, e.g. industrial purposes, individual space heating, heat recovery and district heat production. Today all small heat pump systems used for individual space heating are driven by electricity.

For mechanically driven heat pumps, the heat output will be 2 to 5 times (the coefficient of performance) the drive energy. The energy flow is illustrated in the Sankey diagram in figure 1 below:

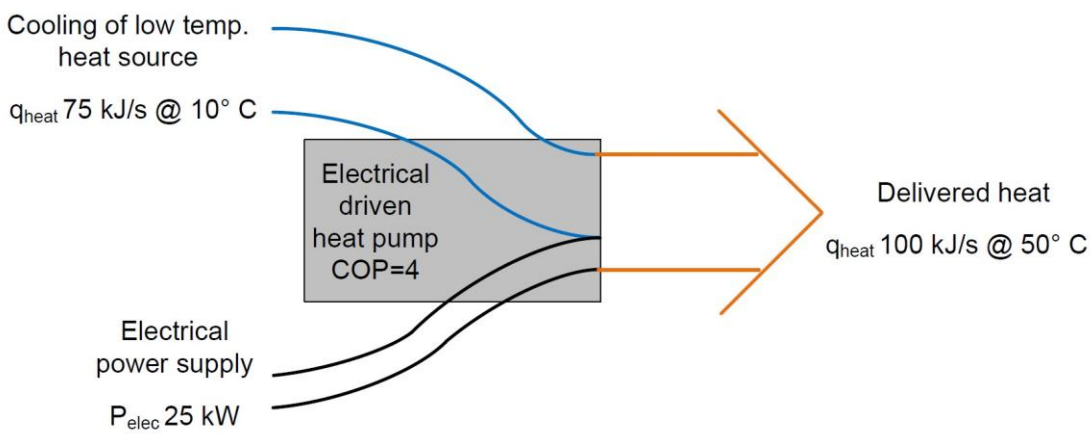


Figure 1: The electrical power consumption of 25 kW enables the heat pump to utilize 75 kJ/s from a low temperature heat source at 10° C. Thus delivering 100 kJ/s at 50° C.

It is not possible to make general formulas for calculating the coefficient of performance (COP) since the efficiency of the systems can vary significantly depending on the compressor type etc. The theoretical COP is given by the temperature of the input and output heat:

$$COP = \frac{Heat\ output}{Energy\ input} = \frac{T_{hot}}{T_{hot} - T_{cold}}$$

both temperatures given in Kelvin (K = °C + 273.15)

For example, with a hot temperature of 80°C and a cold temperature of 10°C the theoretical COP is 5.0. In all practical appliances the COP will be lower because of losses in the system, typically around 50-

65% (this is called the Carnot efficiency) of the theoretical COP. This rule-of-thumb is only valid with small temperature differences on both sides (evaporator and condenser) and if the heat pump is used within the optimum operating range of components and refrigerant.

For typical district heating applications, the COP is as shown in the Table 1 (ref. 1):

Expected COP values and preferable HP type		Heating of district heating water			
		30-70° C	40-70° C	30-80° C	40-80° C
Cooling of heat source Heat source tempeture in/out of heat pump	10-5° C	3.2 - 3.8 CO2, NH3	2.8 - 3.4 CO2, NH3	3.1 - 3.5 CO2, NH3	2.7 - 3.2 CO2, NH3
	20-10° C	3.4 - 4.3 CO2, NH3	3.0 - 4.0 CO2, NH3	3.3 - 4.0 CO2, NH3	2.9 - 3.6 CO2, NH3
	30-10° C	4.4 - 4.8 NH3, Hybrid	4.3 - 4.7 NH3, Hybrid	4.2 - 4.6 NH3, Hybrid	4.0 - 4.4 NH3, Hybrid
	30-20° C	5.0 - 5.4 NH3	4.6 - 4.9 NH3	4.5 -4.9 NH3	4.0 - 4.4 NH3, Hybrid
	40-10° C	-	4.6 - 5.1 NH3, Hybrid	-	4.4 - 5.0 NH3, Hybrid
	40-20° C	-	5.2 - 5.6 NH3, Hybrid	-	4.9 - 5.5 NH3, Hybrid
	40-30° C	-	5.9 - 6.3 NH3, Hybrid	-	5.1 - 5.5 NH3, Hybrid

Expected COP values and preferable HP type		Heating of district heating water			
		30-90° C	40-90° C	30-100° C	40-100° C
Cooling of heat source Heat source tempeture in/out of heat pump	10-5° C	2.9 - 3.3 CO2, NH3	2.5 - 3.1 CO2, NH3	-	-
	20-10° C	3.1 - 3.7 CO2, NH3	2.7 - 3.4 CO2, NH3	-	-
	30-10° C	3.8 - 4.3 NH3, Hybrid	3.5 - 3.8 NH3, Hybrid	2.9 - 3.3 Hybrid	2.8 - 3.2 Hybrid
	30-20° C	4.1 - 4.5 NH3	3.7 - 4.1 NH3	2.9 - 3.3 Hybrid	2.8 - 3.2 Hybrid
	40-10° C	-	4.0 - 4.4 NH3, Hybrid	-	3.3 - 3.7 Hybrid
	40-20° C	-	4.2 - 4.6 NH3, Hybrid	-	3.4 - 3.8 Hybrid
	40-30° C	-	4.7 - 5.1 NH3	-	3.7 - 4.1 Hybrid

Table 1: Typical COP for district heating applications. The values regarding NH_3 are only valid for multistage systems. Single stage NH_3 heat pumps will have considerable lower COP values in the temperature ranges displayed.

In absorption heat pumps, heat at a high temperature level is used as drive energy to regenerate the refrigerant, so that it can evaporate at a low temperature level and utilize low grade energy. Energy from both drive heat and the low temperature heat source is delivered at a temperature in between. Theoretically 1 kJ of heat can regenerate 1 kJ of refrigerant meaning that an absorption heat pump has a theoretical COP of 2. Due to losses inside the system the practical COP is around 1.7. For absorption heat pumps the COP is not affected by temperature levels in the same way as mechanically driven heat pumps. 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 e.g. a further temperature increase of the drive energy. The energy flow is illustrated in the Sankey diagram in figure 2:

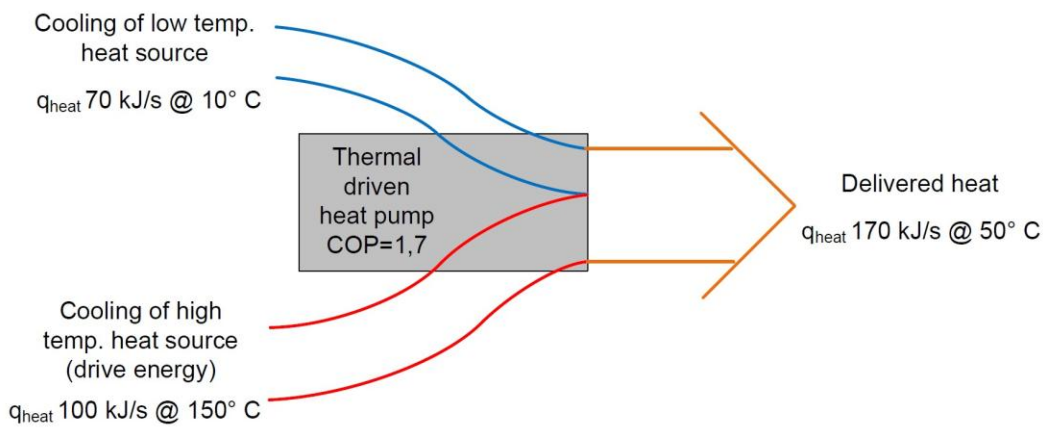


Figure 2: The high temperature drive energy of 100 kJ/s enables the heat pump to utilize 70 kJ/s from a low temperature heat source at 10° C. Thus delivering 170 kJ/s at 50° C.

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 COP of two-stage systems is typically 2.3.

Input
A heat source (e.g. ambient air, water or ground, or waste-heat from an industrial process) and energy to drive the process. Typical Danish temperatures are 0-18 °C as ground temperature and 5-10 °C as groundwater temperature. Compressor heat pumps are driven by electricity or engines, whereas absorption heat pumps are driven by heat; e.g. steam, hot water or flue gas, but also consume a small amount of electricity.

In Denmark the heat source is primarily renewable energy, i.e. accumulated solar heat in top soil layers, in ambient air, in lakes, streams or sea water. Also waste heat from industrial processes can be utilized as heat source, as well as heat in waste water.

Output
Heat.

Absorption heat pumps can in principle deliver temperatures up to 94 ^{o}C, but to avoid instability the temperature should not exceed 85-87 ^{o}C (ref. 4).

Typical capacities
The capacity of small heat pumps is 0.5 to 25 kJ/s heat output. Large heat pumps are available from 25 kJ/s to 3-5 MJ/s heat output. Larger heat pumps than 3-5 MJ/s will typically be a number of heat pump units in parallel.

Regulation ability
The use of heat pumps can be beneficial for the overall electricity system in converting electricity to heat at high efficiencies in times of surplus electricity generation. This feature becomes increasingly valid, when more intermittent renewable energy generators are present in the power system.

Large heat pumps are usually regulated continuously. In starting from cold, electricity consumption is full load fast, typically in less than 5 minutes.

Research and development
The phasing out of the ozone depleting refrigerants CFC and HCFC from the heat pump market has been agreed internationally. The heat pump industry has introduced refrigerants, which are not ozone depleting. It is primarily the so called HFC refrigerants that have been developed to replace the CFC and HCFC refrigerants, but the HFC's contribute to global warming and therefore work has been initiated in order to make sure that these also are phased out. From 2007 it has not been allowed to use more than 10 kg of synthetic refrigerant in cooling or heat pump installations in Denmark. Therefore, natural refrigerants must be used in larger heat pump installations. These are among others hydrocarbons (propane, butane and iso-butane), carbon dioxide, ammonia, and water. The use of these refrigerants does not decrease the energy efficiency, on the contrary if anything.

At the moment the most interesting technologies are CO_2, ammonia, water vapour and hybrid systems (H_2O/NH_3). No single refrigerant is valid for all applications and each of the technologies is "best choice" in certain applications.

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 evaporate at a constant temperature. This means that CO_2 is particular 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. Such an application could be recovering heat from a water treatment plant by cooling the water from 10 – 5° C, while delivering the heat to a district heating system by heating the water from 40 – 80° C. The maximum 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.

Ammonia as a refrigerant condenses and evaporates at constant temperatures, meaning that heat is both withdrawn and provided at almost constant temperature. Because of this, a one-stage ammonia heat pump is not very well suited for large temperature glides on either cold or warm side. If the application requires a high temperature lift ammonia heat pumps should be done in two or more stages. Hereby

each stage will lift the temperature a number of degrees in series exploiting the low temperature changes of the refrigerant. The maximum temperature of current ammonia systems is app. 90° C, but research is done to take the temperature even higher.

At the moment new compressor types for water vapour is being developed. The models available are primarily for district cooling applications, meaning that the temperature is not suitable for heating purposes. However as water vapour has a number of advantages (high efficiency compressors, non toxic, non flammable, elimination of heat exchangers etc.), this technology is expected to be developed for higher temperatures in the near future. For now, low temperature water vapour systems can be used in combination with other system types, 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 Hybrid H_2O/NH_3 heat pump combines the absorption and the vapour compression cycles, hence the name hybrid. The refrigerant NH_3 is absorbed by H_2O and condenses. But instead of using heat for regenerating the water, a mechanical compressor is used for evaporating NH_3 from the solution. As ammonia is absorbed into water throughout the condenser, the ammonia concentration increase as the water passes through the exchanger. This means that the condensing temperature decreases throughout the heat exchanger, and vice versa in the evaporator. Because of this, the hybrid heat pump has temperature glides on both warm and cold side, meaning that it is well suited for applications that can utilize these glides. An example is recovering industrial waste heat by cooling process water from 40 – 10° C, while delivering the heat to a district heating system water is heated from 40 – 80° C. Currently the maximum temperature is app. 130° C, but research is done to take the temperature even higher.

Besides the further development of natural refrigerants it is expected that technology development will focus on:

- Higher outlet temperatures.
- Combinations of the different technologies, e.g. CO_2 – Hybrid, H_2O – NH_3 etc.
- Optimise the benefits for the overall electricity system of using heat pumps.
- Increase the efficiencies of all types of heat pump systems.
- Use of heat pumps combined with combined heat and power production.
- Further development of heat pumps driven by natural gas.

Advantages/disadvantages compared to other technologies

A general advantage of heat pumps is that the heat pump is able to utilize energy at a low temperature level. Additionally the heat pump is flexible concerning use of renewable energy, waste and surplus heat. The combined utilization of a heat source at a low temperature level and the use of for example gas as driving power enables more effective resource utilization compared with conventional heat production technologies.

Compared with traditional heating technologies, heat pumps are more complex and have high investments costs. However, this is counterbalanced by considerable savings in operating costs.

Environment
Harmless refrigerants are currently replacing the former previous refrigerants at large scale.

As heat pumps need drive energy (electricity, oil or gas) the environmental impact from using heat pumps stems from the production and use of the drive energy.

Additional remarks
The data for 'hot' heat pumps is based on a heat source of 35°C; otherwise the average outdoor temperature is used as heat source. If other heat sources are used e.g. in connection with decentralised CHP systems, the COP values would be considerably higher. This could be heat sources such as flue gas cooling, heat from intercooler or waste heat from gas engines.

Investment cost of high temperature heat pumps in M€ per MJ/s, is typically the same for the different technologies, when only the heat pump itself is considered.

Concerning financial data mentioned in the data sheets, the span of investment costs and O&M costs is expected to cover the future. Investment costs are not expected to fall and O&M costs may increase slightly in the future.

The total investment cost of a CO_2 heat pump is comprised of (ref. 2):

Heat pump:	55-60%.
Container (no building):	3 %
Connections and other costs:	35-40%.

Based on a single case, the total investment cost of an absorption heat pump for flue gas condensation is comprised of (ref. 5):

Heat pump:	50%.
Pipe connections:	12%
Chimney anti-corrosion:	13%
Other costs:	25%.

In this case, there was already a steel chimney. This needed anti-corrosive protection.

References

1. Danish Technology Institute, 2011
2. Advansor, 2009
3. Presentation "Varmepumper i ATES", DONG Energy, March 2009.
4. DONG Energy, October 2009.
5. Vestforbrænding, November 2009.

Data sheets

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 35°C
- Large absorption heat pumps – flue gas condensation (steam driven)
- Large absorption heat pumps – geothermal (steam driven)

Technology	**Large heat pumps, electric (heat source: ambient temperature)**					
	2015	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Generation capacity for one unit (MJ/s heat)	**1-10**					
Coefficient of performance	2,8	2,9	3	3,2	A	1,2
Forced outage (%)						
Planned outage (weeks per year)						
Technical lifetime (years)	20	20	20	20		1,2
Construction time (years)	0.5-1	0.5-1	0.5-1	0.5-1		1,2
Environment						
Refrigerants	neutral				A	
Financial data						
Specific investment (M€ per MJ/s heat out)	0.52 - 0.84	0.47 - 0.79	0.42 - 0.73	0.37 - 0.68	C+D	1,2
Total O&M (€ per MJ/s heat out per year)	3700 - 7300	2400 - 4900	2400 - 4900	2400 - 4900	B+D	1

References:

1 Advansor 2009

2 "Varmepumper og lavtemperaturfjernvarme. Rapportering fra to workshops. Delrapportering fra EFP projekt: Effektiv fjernvarme i fremtidens energisystem" (heat pumps and low temperature heat, workshop reports in Danish), Ea Energianalyse A/S, Risø DTU, og RAM-løse edb og Dansk Fjernvarmes visionsudvalg, 2009.

Notes:

A It is assumed that CO2 is used as refrigerant. Supply temperature about 80C.

B A typical service contract is estimated 2,000-3,000 €/year, for the larger sizes. Furthermore an overall check is needed for every 10000 hrs of operation costing approximately 1500 € per MJ/s out.

C These costs include pipes, electrical system, installation etc. It does not include buildings or storage tanks. The heat pumps alone would cost between 0.3 and 0.5 M€ per MJ/s heat out.

D Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.0478

Technology	Large heat pumps, electric (heat source: 35 C)					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generation capacity for one unit (MJ/s heat)	**1-10**					
Coefficient of performance	3,6	3,7	3,8	3,8	A	1,2
Forced outage (%)						
Planned outage (weeks per year)						
Technical lifetime (years)	20	20	20	20		1,2
Construction time (years)	0.5-1	0.5-1	0.5-1	0.5-1		1,2
Environment						
Refrigerants	neutral				A	
Financial data						
Specific investment (M€ per MJ/s heat out)	0.47-0.89	0.42-0.84	0.37-0.79	0.31-0.73	C	1,2
Total O&M (€ per MJ/s heat out per year)	3700 - 7300	2400 - 4900	2400 - 4900	2400 - 4900	B+D	1

References:

1 Advansor 2009

2 "Varmepumper og lavtemperaturfjernvarme. Rapportering fra to workshops. Delrapportering fra EFP projekt: Effektiv fjernvarme i fremtidens energisystem" (heat pumps and low temperature heat, workshop reports in Danish), Ea Energianalyse A/S, Risø DTU, og RAM-løse edb og Dansk Fjernvarmes visionsudvalg, 2009.

Notes:

A It is assumed that CO2 is used as refrigerant. Supply temperature about 80C.

B Electricity consumption is excluded. A typical service contract is estimated 2,000-3,000 €/year, for the larger sizes. Furthermore an overall check is needed for every 10000 hrs of operation costing approximately 1500 € per MJ/s heat out.

C These costs include pipes, electrical system, construction etc. The heat pumps alone would cost between 0.3 and 0.5 M€ per MJ/s heat out.

D Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.0478

Technology	Large heat pumps, absorption (flue gas condensation)					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generation capacity for one unit (MJ/s heat)	**2-15**					
Coefficient of performance Technical lifetime (years)	1,7 20	1,75 20	1,8 20	1,85 20	A	1+2
Construction time (years)	0.5-1	0.5-1	0.5-1	0.5-1		
Environment						
Refrigerants	Ammonia - LiBr					
Financial data						
Specific investment (M€ per MJ/s heat out)	0.37-0.42				C	3+4
Total O&M (€ per MJ/s heat out per year)	16-21000				B+C	4

References:

1 Vestforbrænding presentation, Danish Committee for Waste (DAKOFA) conference, December 2007.

2 DONG Energy, October 2009.

3 "Total udnyttelse af energien i Bjerringbro" (total energy utilization in Bjerringbro; in Danish), Fjernvarmen (Danish periodical for district heating), no. 1, 2008.

4 Vestforbrænding, November 2009.

Notes:

A Heat pumps used in connection with flue gas condensation to increase overall efficiency of MSW and biomass plants. Condensation heat from the flue gas is used as heat input to raise the district heating temperature from 40-60 C to about 80 C.

B 5% of initial investment per year. Almost all O&M cost is for for discharging the condensate water. However, at Vestforbrænding (incinerator) this cost is zero, since all condensate water is reused in an acid scrubber for flue gas cleaning (ref. 4). Cost of cleaning the condensate water before discharge is not included. Manpower to operate the heatpump is insignificant.

Costs for steam to drive the heat pump and electricity for pumps etc. are not included.
The electricity consumption for internal pumps is about 1-2 % of the heat extracted from the heat source by the evaporator (ref: 2+4).

C Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.0478

41 ELECTRIC BOILERS

Brief technology description
An electric boiler is used for producing hot water directly from electricity. Two types of installations are available:

- The heating elements using electrical resistance (same principal as a hot water heater in a normal household). Typically, electrical resistance is used for smaller applications up to 1-2 MW's. These electric boilers are connected at 400 V.
- Heating elements using electrode boilers. Electrode systems are used for larger applications (larger than a few MW's). In Denmark, larger electrode boilers (larger than a few MW's) are connected at 10 kV.

The water in the electrode boiler is heated by means of an electrode system consisting of three-phase electrodes, a neutral electrode and control screens. Power is fed to the electrodes which transfer it to the water, thus heating the water.

The current from the phase electrodes flows directly through the water, which is heated in the process. The current is a function of the active surface area of the electrodes and the water conductivity. The active area of the electrodes can be infinitely varied by operating the control screens, thus enabling output to be controlled between a minimum load of 10-20 % (depending on boiler size and voltage) and 100 %.

Input
Electricity.

Output
Heat (hot water).

Typical capacities
1 - 25 MW.

Regulation ability
The electrode boiler output can be adjusted by means of the control screens which are mounted on a motor-driven gear shaft so that they can be moved up and down along the electrodes. In this way it is possible to adjust the output from approx. 10-20% up to 100%.

Environment
The boiler has no local environmental impact. However, it uses electricity and the environmental impact is highly dependent of the origin of the electricity.

Advantages/disadvantages
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 start up and is easy to regulate. It requires no fuel feeding systems or stack. However, as it uses electricity as fuel, the operating costs can be high compared to other boilers.

The investment costs are very dependent on the size of the boiler.

Research and development
The technology is well developed and tested and commercially available. Future development will focus on dynamic use of electric boilers in connection with the power system.

Examples of best available technology
Swedish boiler manufacturer, Zander & Ingeström AB, distributed by Averhoff Energi Anlæg in Denmark.
Swedish boiler manufacturer, Värmebaronen (smaller electric boilers up to 1.5 MW).

Special remarks
The operating costs of an electric boiler are highly dependent on the electricity price. Thus, heat production from of electric boilers can only compete with other heat production units at low electricity prices (i.e. at periods with high wind power production). Furthermore, electric boilers can be used for upward or downward regulation in the power systems with short notice. For upward regulation the electric boiler needs to be in operation to deliver this service.

The investment cost stated in the data sheet is without grid connection, which may more than double the cost.

References
Averhoff Energi Anlæg, web page and personal communication 2009.
Zander & Ingeström AB, 2009.

Data sheet

The costs presented below do not include the installation of a hot water storage tank.

Technology	Electric boilers					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generation capacity for one unit (MW)	1-25					
Efficiency (%)	99	99	99	99		1
Technical lifetime (years)	20	20	20	20		
Construction time (years)	0.5-1	0.5-1	0.5-1	0.5-1		
Environment						
Local emissions	-				A	
Financial data						
Nominal investment (M€/MW); 400 V; 1-3 MW	0.13-0.16	0.13-0.16	0.13-0.16	0.13-0.16	B;C;D	2,3
Nominal investment (M€/MW); 10 kV; 10 MW	0.06-0.09	0.06-0.09	0.06-0.09	0.06-0.09	C;D	2,3,4
Nominal investment (M€/MW); 10 kV; 20 MW	0.05-0.07	0.05-0.07	0.05-0.07	0.05-0.07	C;D	2,3
Fixed O&M (€/MW per year)	1100	1100	1100	1100	D	2
Variable O&M (€/MWh)	0.5	0.5	0.5	0.5	D	2

References:

1 Zander & Ingeström AB, web page, October 2009
2 Averhoff Energi Anlæg, personal communication, May 2009
3 Security of supply for Bornholm, Integration of fluctuating generation using coordinated control of demand and wind turbines, Demand side options for system reserves, Ea Energy Analyses 2007
4 "Erfaringer med centrale elpatroner og varmepumper", Jan Diget, Skagen Varmeværk at "Vind til varme og transport", conference held by the Danish Wind Industry Association, October 22, 2009
5 JPH Energi A/S; 2008.
6 Energinet.dk, 2009.

Notes

A Environmental impacts depends on how the electricity for the boiler is produced.
B If this small boiler needs to take the electricity from a 10 kV grid, a transformer is required. This costs around 0.14 M€/MW (ref. 5).
C Costs do not include extra costs for connecting to the grid. Costs of strengthening the local grid and transformer-station, if required, may be around 0.13 M€/MW (ref. 6).
D Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

42 WASTE-TO-ENERGY DISTRICT HEATING PLANT

Brief technology description
The major components are: A waste reception area, a feeding system, a grate fired furnace interconnected with a hot or warm water boiler, an extensive flue gas cleaning system and systems for handling of combustion and flue gas treatment residues.

The plant is primarily designed for incineration of municipal solid waste (MSW) and similar non-hazardous wastes from trade and industry. Some types of hazardous wastes may, however, also be incinerated.

The waste is delivered by trucks and is normally incinerated in the state in which it arrives. Only bulky items are shredded before being fed into the waste bunker.

Input
MSW and other combustible wastes, water and chemicals for flue gas treatment, gas oil or natural gas for auxiliary burners (if installed).

The low heating value of MSW is (ref. 3):

Europe:	7,500 – 10,500 kJ/kg
Japan:	5,000 – 10,500 kJ/kg
USA:	9,000 – 15,000 kJ/kg

In Copenhagen, the heating value has increased from 9.8 kJ/kg in 2004 to 10.5 kJ/kg in 2008 and is expected to further increase to 11.5 kJ/kg by 2025.

Output
Heat as hot (> 120 ^{o}C) or warm (<120 ^{o}C) water, bottom ash (slag), residues from flue gas treatment, including fly ash. If the flue gas is treated by wet methods, there may also be an output of treated process wastewater.

Typical capacities
5-15 tonnes of waste per hour, corresponding to a thermal input in the range 15-50 MJ/s. Plants larger than 15 tonnes/hour would typically be designed for combined heat and power.

Regulation ability
The plants can be down regulated to 60% of the nominal capacity, but for emissions control reasons they should be operated at base load.

Advantages/disadvantages
By incinerating the non-recyclable, combustible waste its energy content is utilised thereby replacing equivalent quantities of energy generated on fossil fuels. Moreover, the waste is sterilised, and its

volume greatly reduced. The remaining waste (bottom ash/slag) may be utilised in construction works, and it will no longer generate methane. Consequently, by incinerating the waste, the methane emission generated, when landfilling the same quantity of waste, is avoided.

The disadvantages are that a polluted flue gas is formed, requiring extensive treatment, and that the flue gas treatment generates residues, which are classified as hazardous waste.

Environmental aspects
The incineration of MSW involves the generation of climate-relevant emissions. These are mainly emissions of CO_2 as well as N_2O, NOx and NH_3. CH_4 is not generated in waste incineration during normal operation.

Waste is a mixture of CO_2 neutral biomass and products of fossil origin, such as plastics. A typical CO_2 emission factor is 37.0 kg/GJ for the waste mixture currently incinerated in Denmark.

To comply with European Union requirements (Directive 2000/76) the flue gas must be heated to min. 850 ^{o}C for min. 2 seconds and the gas must be treated for NO_x, dust (fly ash), HCl, HF, SO_2, dioxins and heavy metals. If HCl, HF and SO_2 are removed by wet processes, the wastewater must be treated to fulfil some specific water emission limit values.

The solid residues from flue gas and water treatment are hazardous wastes and are often placed in an underground storage for hazardous waste (cf. Council Decision 2003/33).

Ecological footprints are: air and water emissions including dioxins as well as solid residues to be disposed of.

Research and development
There is a potential of increasing the energy efficiency of waste fired district-heating plants by application of condensation of flue gas moisture.

Further challenges are the amount and quality of the residues (bottom ash, fly ash and flue gas cleaning residue). The continued use of bottom ash for road construction etc. is expected to take place under tightening demands on the contents and leachability of a range of pollutants, including salts, heavy metals and dioxin.

Similarly, the amount of hazardous waste (fly ash and flue gas cleaning residue) may be reduced by optimisation of the overall process. Also, treatment of residues may be further developed for recycling and/or disposal in landfills not dedicated for hazardous waste.

Special remarks
The primary objective of a waste-to-energy plant is the treatment of waste, energy production may be considered a useful by-product. Contrary to other fuels used for energy generation, waste usually has a negative price, as it is received at a gate fee. The socio-economic price may be negative or positive, much dependent on how it is calculated.

By condensing most of the water vapour content of the flue gas in the flue gas treatment, a thermal efficiency (based on the net calorific value) of around 100% is achievable. At the same time the plant becomes self-sufficient in water.

References

1. Kleis, H. and Dalager, S.: 100 Years of Waste Incineration in Denmark. Babcock & Wilcox Vølund and RAMBØLL, 2004.
2. Lov om CO_2-kvoter, LOV nr.493 af 09/06/2004. (Law of the Danish parliament on CO_2-allowance trading, cf. Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC)
3. Affald 21, Miljø- og Energiministeriet, 1999, "Waste 21".

Data sheet

Technology	Waste to energy, district heating					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Waste treatment capacity (tonnes/h)	15	15	15			1
Thermal input (MJ/s)	50.0	50.0	50.0			1
Own consumption (MW)	1.2	1.2	1.2			1
Total efficiency (%) gross	98	100	100		A	1
Total efficiency (%) net	95.6	97.6	97.6		A	1
Start-up fuel consumption (GJ)	1080	1080	1080			1
Time for varm start-up (hours)	12	12	12			1
Forced outage (%)	1	1	1			1
Planned outage (weeks per year)	3	3	3			1
Technical lifetime (years)	20	20	20			1
Construction time (years)	3	3	3			1
Environment						
SO_2 (degree of desulphurisation, %)	98.0	98.4	98.4			1
NO_X (g per GJ fuel)	164	164	164	164		2;3;3;3
CH4 (g per GJ fuel)	6	6	6	6		2;3;3;3
N2O (g per GJ fuel)	4	4	4	4		2;3;3;3
Financial data						
Specific investment (M€/MW)	1.2	1.1	1.1		B	1
Fixed O&M (€/MW/year)	54000	53000	53000		B	1
Variable O&M (€/MWh)	5.6	5.4	5.4		B	1
Regulation ability						
Minimum load (% of full load)	75	75	75			1

References:

1 Rambøll Danmark, September 2004
2 National Environmental Research Institute, Denmark, 2009 (data from 2007).
3 Danish Energy Agency, 2011

Notes:

A With flue gas condensation
B Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying with a general inflation factor 1.2306

43 DISTRICT HEATING BOILER, BIOMASS FIRED

Brief technology description
Boiler fired by wood-chips from forestry and/or from wood industry, wood pellets or straw.

If the moisture content of the fuel is above 30-35%, as with forest wood-chips, flue gas condensation should be employed. Thereby the thermal efficiency usually exceeds 100 % (based on lower heating value). The efficiency is primarily determined by the condensation temperature, which is little above the return temperature from the district heating network. In well-designed systems, this return temperature is below 40 ^{o}C, yielding efficiencies above 105 %.

For plants firing wood-chips with 45 – 55 % moisture content, the thermal efficiency exceeds 110 %. Some plants are equipped with cooling devices for full flue gas condensation and thermal efficiencies of more than 120 % are reached (ref. 3).

Flue gas condensation should not be applied to plants below 1 - 2 MJ/s due to O&M costs. Such plants should only use fuels drier than 30 % moisture content (ref. 3).

Straw fired boilers are normally equipped with a bag filter for flue gas cleaning. Electro filters do not work with straw firing as they do with wood firing.

Flue gas condensation is now available also for straw firing but must be combined with a bag filter to hold back calcium chlorine particles from the scrubber. The flue gas condensation raises the efficiency with 5-10 % and reduces SO_2 emission to a minimum, when the pH value is kept above 6.5 – 7.0 (ref. 3). Whether flue condensation is feasible is much dependent on taxes, e.g. on sulphur.

Input
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.

Existing district heating boilers in Denmark can burn wood-chips with up to 45-63 % moisture content, depending on technology. In 1993, the actual moisture content was 42 % in average, varying between 32 and 48 % (ref. 1).

The wood-chips are often traded in two size qualities, coarse and fine.

Other possible fuels are chipped energy crops (e.g. willow and poplar) and chipped park and garden waste.

Wood pellets are made from sawdust, wood shavings and other residues from sawmils 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 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 a high combustion efficiencies.

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, approx. 5-700 kg each, from stores at the farms to the district heating plants etc. during the year depending on crop delivery contracts.

Output
District heat or heat for industrial processes.

Typical capacities
1 - 50 MJ/s.

Regulation ability
Typical wood fired pants are regulated 25 - 100% of full capacity, without violating emission standards. The best technologies can be regulated 10 - 120% with fuel not exceeding 35 % moisture content.

Straw fired plants should not be operated below approx. 50 % of full load due to emission standards. Straw fired plants should accordingly be equipped with an accumulating tank allowing for optimal operational conditions.

Environment
NOx emissions may be reduced, by about 60-70%, by selective non-catalytic reduction (SNCR). For a district heating plant size 4-8 MJ/s, this would cost about 0.1 M€ in investment and 400 € pr. tonne NOx in operational cost (ref. 4).

Biomass fired boilers produce four sorts of residues: Flue gas, fly ash, bottom ash, and possibly condensate from flue gas condensation.

All bottom ash and most fly ash from straw firing are recycled to farm land as a fertilizer.
Almost all ash from wood firing is dumped in landfills. Research is ongoing on how to carbonize the ash for recycling to the forests.

The condensate water from wood firing is usually treated for Cadmium, so that the content reaches 3 – 10 grams per 1000 m^3. The sludge must be deposited in a safe landfill.
Condensate from straw-firing can be expelled without cleaning, as almost all Cadmium is withheld with the fly ash in the bag filter.

Research and development
There is still a need for R&D in the following areas:

- environmentally safe recycling of ashes to forestry; e.g. by pellets to ensure slow release of nutrients;

- reduction of aerosols and NOx;
- handling and combustion of new types of fuels, such as energy crops and garden waste.

Examples of best available technology
Danish manufacturers of best available technology for wood firing are Justsen A/S, Weiss A/S, Eurotherm A/S and Hollensen Energy A/S, while the newest operational plants can be visited in the cities of Brande, Sønderborg, Fuglebjerg and Nykøbing Falster (REFA).

Danish manufacturers of best available technology for straw firing are Weiss A/S, Eurotherm A/S, Hollensen Energy A/S and Lin-Ka Energy A/S, while the newest operational plants can be visited in the cities of Øster Toreby, Høng, Ringsted and Terndrup.

Danish manufacturer of best available technology for cleaning of flue gas condensate is AL-2 Teknik A/S (ref. 3).

References

1. Videncenter for Halm og Flis-fyring. anlægs- og driftsdata for flisfyrede varmeværker. 1994.
2. Videncenter for Halm og Flis-fyring. Træ til energiformål. 1999.
3. Danish District Heating Association, January 2012.
4. "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.

Data sheets

Technology	District heating boiler, wood-chips					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one plant (MJ/s)	1 - 12	1 - 12	1 - 12			1
Total efficiency (%) net	108	108	108			1
Availability (%)	96-98	96-98	96-98			2
Technical lifetime (years)	20	20	20			1
Construction time (years)	0.5 - 1	0.5 - 1	0.5 - 1			2
Environment						
SO_2 (g per GJ fuel)	1.9	1.9	1.9	1.9		4;3;3;3
NO_X (g per GJ fuel)	81	81	81	81		4;3;3;3
Unburned hydrocarbon, UHC (g per GJ fuel)	6.1	6.1	6.1	6.1		4;3;3;3
N_2O (g per GJ fuel)	0.8	0.8	0.8	0.8		4;3;3;3
Financial data						
Nominal investment (M€ per MJ/s)	0.5 - 1.1	0.5 - 1.1	0.5 - 1.1			1
Total O&M (€/MWh)	5.4	5.4	5.4			1

References:

1 Danish District Heating Association, January 2012
2 Elsams og Elkrafts opdatering af Energistyrelsens 'Teknologidata for el- og varmeproduktionsanlæg', 1997
3 Danish Energy Agency and Energinet.dk, 2011
4 "Emisions map for combined heat and power production 2007", National Environmental Research Institute, Denmark, 2010.

Technology	District heating boiler, wood-pellets					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one plant (MJ/s)	< 2				A	
Total efficiency (%) net						
Availability (%)						
Technical lifetime (years)						
Construction time (years)						
Environment						
SO_2 (degree of desulphuring, %)						
NO_X (g per GJ fuel)						
CH4 (g per GJ fuel)						
N2O (g per GJ fuel)						
Financial data						
Nominal investment (M€ per MJ/s)	0.25 - 0.55	0.25 - 0.55	0.25 - 0.55			1
Total O&M (€/MWh)	2.7	2.7	2.7			1

References:

1 Danish District Heating Association, January 2012

Notes:

A Wood pellets are not attractive for plants above 1-2 MJ/s, since alternative fuels are much cheaper, when it comes to larger plants.

Technology	District heating boiler, straw					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one plant (MJ/s)	1 - 12	1 - 12	1 - 12			1
Total efficiency (%) net						
Availability (%)						
Technical lifetime (years)						
Construction time (years)						
Environment						
SO_2 (g per GJ fuel)	49	49	49	49		2;3;3;3
NO_X (g per GJ fuel)	125	125	125	125		2;3;3;3
Unburned hydrocarbon, UHC (g per GJ fuel)	0.94	0.94	0.94	0.94		2;3;3;3
N_2O (g per GJ fuel)	1.1	1.1	1.1	1.1		2;3;3;3
Financial data						
Nominal investment (M€ per MJ/s)	0.5 - 1.1	0.5 - 1.1	0.5 - 1.1		A	1
Total O&M (€/MWh)	4.0	4.0	4.0			1

References:

1 Danish District Heating Association, January 2012

2 "Emisions map for combined heat and power production 2007", National Environmental Research

3 Danish Energy Agency and Energinet.dk, 2011

Notes:

A Small units, up to 2 MJ/s, may be cheaper (around 0.4 - 0.8 M€ per MJ/s), when designed with semi-automatic fuel handling. However, manual storage increases operation costs (ref. 1).

44 DISTRICT HEATING BOILER, GAS FIRED

Brief technology description
The fuel is burnt in the furnace section. Heat from the flames and the exhaust gas is used to heat water in the boiler section.

Boilers for district heating have been used for decades. Today most boilers are used for peak-load or back-up capacity and for balancing the electric production at CHP plants when market prices for electricity are low.

Boilers may be equipped with supplementary economizer to reduce heat loss through the flue gas.

Input
Natural gas, with heavy fuel oil or gas oil as back-up fuel.

Output
District heat.

Typical capacities
0.5-20 MJ/s.

Environment
The only residue results from scales[2].

Research and development
It is a commercial technology with insignificant need for R&D.

[2] The hard greyish-white material sometimes deposited inside the furnace section, pipes, etc by water when it is heated.

Data sheet

Technology	District heating boiler, gas fired					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one plant (MJ/s)	0.5 - 10	0.5 - 10	0.5 - 10			2
Total efficiency (%) net	97 - 105	97 - 105	97 - 105		A	5
Availability (%)	98 - 99	98 - 99	98 - 99			2
Technical lifetime (years)	30 - 40	30 - 40	30 - 40			2
Construction time (years)	0.5 - 1	0.5 - 1	0.5 - 1			1
Environment (Fuel: natural gas)						
NO_X (g per GJ fuel)	10 - 13	9 - 12	8 - 11	7 - 10		5
CH4 (g per GJ fuel)	< 3	< 3	< 3	< 3		5
N2O (g per GJ fuel)	1	1	1	1		4;3;3;3
Financial data						
Nominal investment (M€ per MJ/s)	0.07 - 0.13	0.07 - 0.13	0.07 - 0.13			2
Total O&M (€ per MJ/s per year)	1200 - 6200	1200 - 6200	1200 - 6200			1

References:

1 Elsams og Elkrafts opdatering af Energistyrelsens 'Teknologidata for el- og varmeproduktionsanlæg', 1997
2 Danish District Heating Association, 2012
3 Danish Energy Agency, 2009
4 National Environmental Research Institute, Denmark, 2009 (data from 2007).
5 Danish Gas Technology Centre, 2012

Notes:

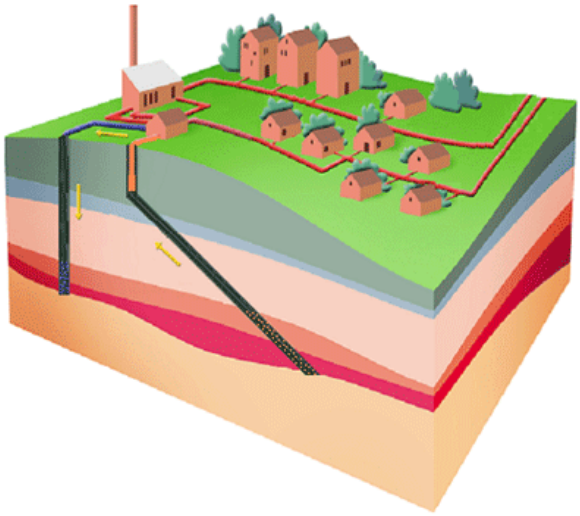
A The highest efficiencies are due to flue gas condensation.

45 GEOTHERMAL DISTRICT HEATING

Brief description
Geothermal energy is energy located in underground water reservoirs of the earth. In average the temperature of the reservoir increases with around 3 ºC per 100 m depth. Recent definitions of geothermal energy include all heat from the ground. Only heat produced through deep wells is described.

Heat from deep reservoirs can be utilized directly through a heat exchanger. However, both the temperature and the pumping costs increase with the depth. From Danish experiences it is thus economically more attractive to use heat pumps and extract heat from higher reservoirs, typically at 800-3000 m depth, where temperatures are 30-90 ^{o}C. The heat pumps can either be compressor heat pumps driven with electricity or absorption heat pumps driven by heat. The geothermal water is saline - often with 10-20% salinity.

In the doublet design, warm geothermal water is pumped to the surface from a production well and the heat depleted brine pumped back into the source reservoir via an injection well; the bottom-hole spacing is designed to avoid premature cooling of the production well.



The principle of the doublet design
(ref: www.geotermi.dk).

Several boreholes may also be drilled from one site. This will decrease the cost of heat. Also, one or more of the boreholes may then be used for heat storage, e.g. seasonal, by injection of hot water during the summer and production during winter. Stored hot water can increase well capacities. The storage of hot water may, however, carry precipitation problems and change reservoir properties, and a study is planned to assess benefits and problems associated with heat storage (ref. 2).

Absorption heat pumps driven by district heating biomass boilers can be used to elevate the temperature of the produced heat and increase the heat extraction, e.g. cooling the reinjected water to 10-20 ^{o}C. In some cases the cooling by heat pumps can help to reduce gas separation (from the water) and avoid precipitation, which may clog the reinjection well.

Heat produced from deep wells in Denmark can be divided into the following systems:

- Heat for district heating

Heat from saline water in porous sandstone layers, typically 1000-2500 meters below surface. From these reservoirs it is possible to reach temperatures of 30-80 ºC. The geothermal system consists of a production well, heat exchangers and/or heat pumps transferring heat into the district-heating network and a reinjection well returning the cooled water to the same reservoir maintaining the reservoir pressure.

- Heat for district heating including storage and use of stored heat at elevated temperature. Geothermal aquifers found suitable for heat storage may be used to store heat at elevated temperature levels increasing production capacities and temperatures (ref. 2).

Geothermal district heating (GDH) in Europe is nearing a total capacity of 5,000 MJ/s. The two largest schemes address the heating of the city of Reykjavik and of the Paris suburban area.

GDH provides almost all of Reykjavik's district heating demand with an installed capacity of 830 MJ/s serving 180,000 people, 60 million m^3/year of water at an average 75°C (user inlet) temperature. An important part of the hot water supply is piped from distant wells and there is no reinjection of the heat depleted water (ca 35°C) underground.

The Paris Basin GDH system is based on a sedimentary resource and on the doublet concept of heat extraction. Here, hot water at an average temperature of 70°C is pumped from depths of 1500 to 1800 m. The thirty-four geothermal doublets (and as many heating grids), operating since the early 1980's in the Paris area, totalise installed power and generating capacities of 230 MJ/s and 1,000 GWh/year respectively (ref. 3).

About 10 GW electricity generation capacity is installed in the World, primarily as base load (ref. 2).

Input
Heat from brine (saline water) from underground reservoirs.

Output
Heat for district heating.
Electricity, if geothermal temperatures are high.

Typical capacities
10-15 MW per production well without heat storage

Regulation ability
Making an optimised geothermal energy system the general experience is that the geothermal energy should be used as base load, e.g. covering 1/3 of the total district heat supply. The main reason is economy.

Research and development
Heat extraction from hot dry rock layers at e.g. 3000-4000 meters below surface is yet to be investigated in Denmark. The challenge is to increase the extremely small natural fractures, allowing water to be heated to temperature levels, where it can be used for power production.

Heat storage is planned investigated in Denmark - both seasonal heat storage of e.g. solar heat and short-term storage.

Better utilization of the geothermal resources could be achieved through lowering the district heating temperatures.

Advantages/disadvantages compared to other technologies
Advantages:

- Established technology for heat production for district heating
- Cheap running costs and "fuel" for free
- Renewable energy source and environmental friendly technology with low CO_2 emission
- High operation stability and long lifetime
- Potential for combination with heat storage.

Disadvantages:

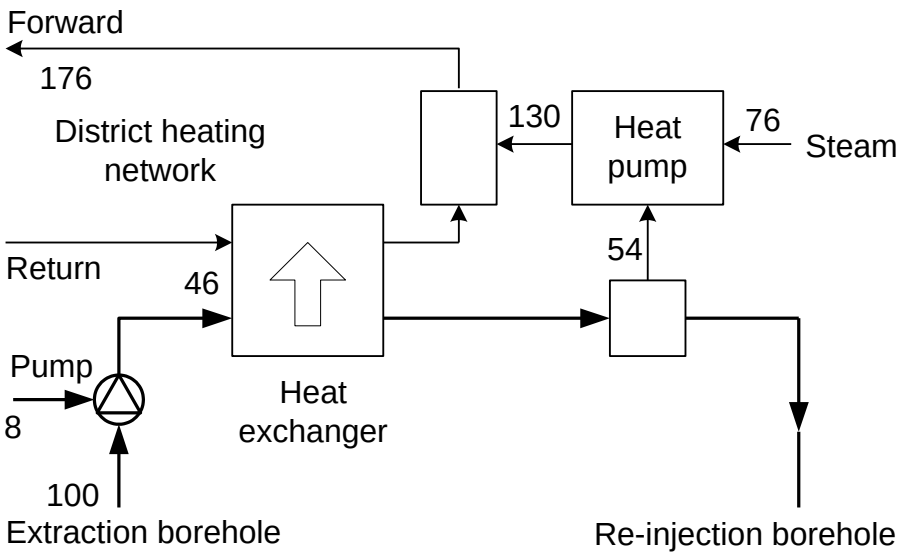
- No security for success before the first well is drilled and the reservoir has been tested
- High initial costs
- The best reservoirs not always located near cities
- Need access to base-load heat demand

Environment
Utilization of geothermal energy is very CO_2 friendly. Pumps pumping the geothermal water typically use power equal to 5-10% of the heat from the geothermal water and CO_2 emission depends primarily on how the heat pump is powered.

Examples of best available technology
Application of seasonal heat storage has been successfully demonstrated in Neubrandenburg, Germany (ref. 1).

A geothermal plant in Thisted, Denmark, has produced heat since 1984 producing heat for district heating. 7 MJ/s heat is extracted from 44 °C thermal water by absorption heat pumps driven by a straw based district heating boiler.

Additional remarks
An example of a system with an absorption heat pump is illustrated below. The numbers indicate the energy flows relative to the extracted amount of geothermal heat, 100 energy units:



Part of the geothermal heat (46) is used for direct heating of the return water from the district heating network, while the remainder (54) is used as heat source for the heat pump (the figure is very simplified, as some return water and all of the water from the heat exchanger is heated inside the heat pump plant). The COP (heat out / drive energy) of the heat pump is 130/76 = 1.7. Thus, the total heat output of the system equals the geothermal input plus the drive energy: 100 + 76 = 176.

The steam to drive the absorption heat pump (76 energy units) may be delivered by a district heating plant (e.g. biomass or waste incineration). If the drive steam is delivered by a combined-heat-and-power plant, the extracted steam will cause a decrease in electricity generation.

Electricity consumption for the geothermal circulation pumps is normally 5-10% of the heat extracted from the geothermal water.

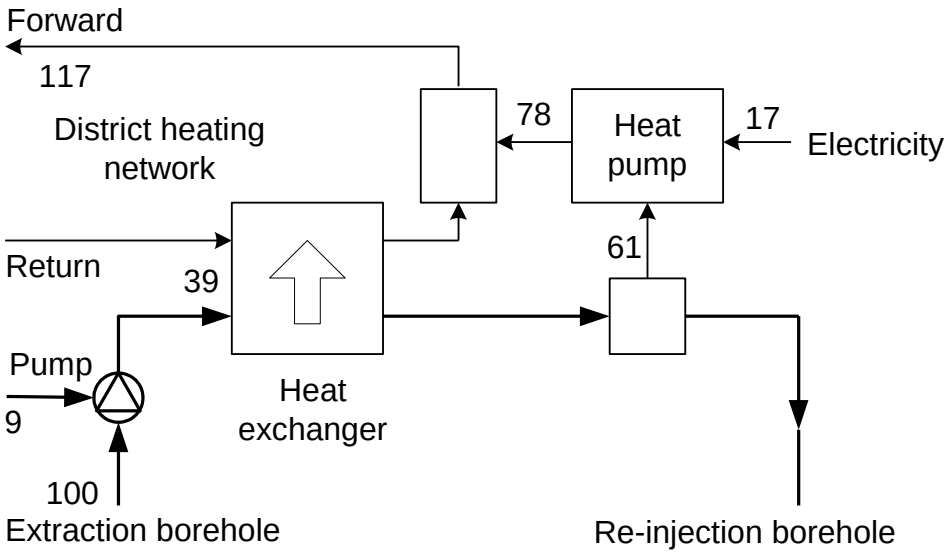
Investment cost structure of typical geothermal plants in Denmark (ref. 2):

Exploration	2%
Wells, well tests	46%
Geothermal surface loop	15%
Heat pump plant	29%
Interest during construction	7%
Total	100%

The heat generation costs depend primarily on geological data (depth, porosity and temperature) and the heat system (heat demand, duration curve and forward/return temperatures). A heat demand exceeding 300 – 500 TJ annually with access to supply base load is normally required.

Electric heat pumps can in some cases extract more geothermal energy than absorption heat pumps. They may cool the geothermal water below the approx. 10-20°C obtainable using absorption heat pumps and their drive energy may constitute a smaller part of the heat output. On the other hand electricity is in general substantially more expensive than heat, making electric heat pumps more expensive to operate.

An example of a system with an electric heat pump is illustrated below.



References

1) "Geotermi – Varme fra jordens indre" (Geothermal energy – Heat from inside the Earth; in Danish); Danish Energy Agency, October 2009.
2) Dansk Fjernvarmes Geotermiselskab, 2011, including www.geotermi.dk
3) The European Geothermal Energy Council, www.egec.org

Data sheets:

Two examples are given. In both cases, steam from a district heating plant is used to drive the absorption heat pump. The heat content of the steam would otherwise have been supplied directly to the district heating network at the same cost, and it has therefore been ignored in the economic data.

Technology	**Geothermal heat-only plant with steam-driven absorption heat pump, Denmark**					
	2010	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Temperature of geothermal heat (degrees C)	70					1
Heat from geothermal source (MJ/s)	15	15	15			1
Steam demand, heat pump (MJ/s)	11	11	11			1
Heat generation capacity (MJ/s)	26	26	26			1
District heat forward temperature, winter (C)	80	80	80			1
Electricity consumption for surface pumps etc. (MW)	1.2	1.2	1.2			1
Electricity consumption for submerged pumps etc. (MW)	1.2	1.2	1.2			1
Technical lifetime (years)	25	25	25			1
Construction time (years)	4-5	4-5	4-5			1
Financial data						
Specific investment (M€ per MJ/s geothermal	1.8	1.8	1.8			1
O&M excl. electricity consumption (€/year per MJ/s geothermal heat)	47000	47000	47000			1

References:

1 Dansk Fjernvarmes Geotermiselskab, 2011

Technology	Geothermal heat-only plant with steam-driven absorption heat pump, Denmark					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Temperature of geothermal heat (degrees C)	50					1
Heat from geothermal source (MJ/s)	13	13	13			1
Steam demand, heat pump (MJ/s)	14	14	14			1
Heat generation capacity (MJ/s)	27	27	27			1
District heat forward temperature, winter (C)	80	80	80			1
Electricity consumption for pumps etc. (MW)	0.61	0.61	0.61			1
Technical lifetime (years)	25	25	25			1
Construction time (years)	4-5	4-5	4-5			1
Financial data						
Specific investment (M€ per MJ/s geothermal heat)	2.0	2.0	2.0			1
O&M excl. electricity consumption (€/year per MJ/s geothermal heat)	49000	49000	49000			1

References:

1 Dansk Fjernvarmes Geotermiselskab, 2011

Technology	Geothermal heat-only plant with electric heat pump, Denmark					
	2010	2020	2030	2050	Note	Ref
Energy/technical data						
Temperature of geothermal heat (degrees C)	70					1
Heat from geothermal source (MJ/s)	64	64	64			1
Electricity demand, heat pump (MW)	5.7	5.7	5.7			1
Heat generation capacity (MJ/s)	74	74	74			1
District heat forward temperature, winter (C)	85	85	85			1
Electricity consumption for pumps etc. (MW)	11	11	11			1
Technical lifetime (years)	25	25	25			1
Construction time (years)	4-5	4-5	4-5			1
Financial data						
Specific investment (M€ per MJ/s geothermal heat)	1.6	1.6	1.6			2
O&M excl. electricity consumption (€/year per MJ/s geothermal heat)	37000	34000	34000			2

References:

1 Dansk Fjernvarmes Geotermiselskab, 2011

2 Estimated by Danish Energy Agency and Energinet.dk, 2011.

46 SOLAR DISTRICT HEATING

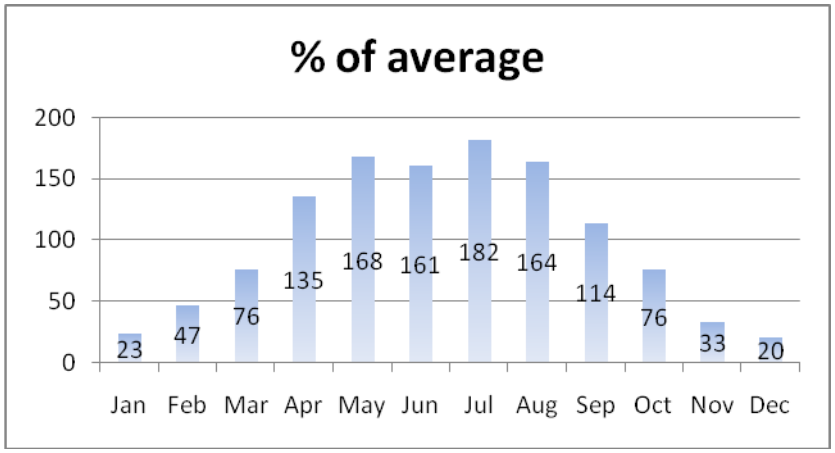
Brief technology description
Using the sun's energy to heat water is not a new idea. Today, more than 30 million m^2 of solar collectors are installed around the globe (ref. 1).

Solar heating systems use solar collectors and a liquid handling unit to transfer heat to the load, generally via a store. When properly designed, solar collectors can work when the outside temperature is well below freezing, and they are also protected from overheating on hot, sunny days.

This technology sheet deals only with large installations used for producing heat to district heating systems. All such systems have additional heat generating capacity to ensure that all of the consumers' heating needs are met, when there is insufficient sunshine. This is typically heat-only boilers or combined heat and power plants.

Input
Solar radiation.

The seasonal variation of heat generation from typical solar collectors in Denmark is shown in the below figure (ref. 3):



Output
District heat.

Typical capacities
There are (end of 2011) about 25 solar district heating systems in Denmark, from 1,000 to 35,000 m^2 of solar collectors. All of them have located the solar collectors on the ground.

Research and development
Danish priorities are (ref. 2):

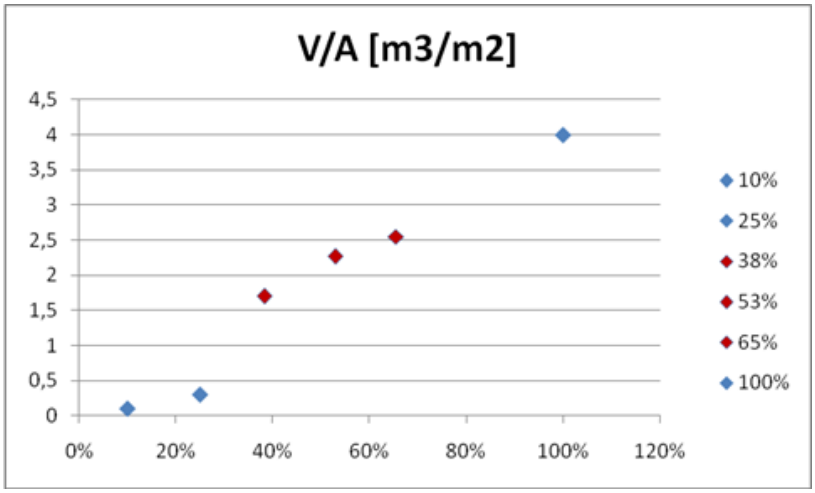
- High-efficiency solar collectors
- Seasonal heat storage, concepts and materials
- Integration of solar heating plants with other heat generating technologies

Examples of best available technology

- Brædstrup, Denmark: A combined energy system including 8000 m^2 of solar collectors, 2000 m^3 heat storage tank, a natural gas fired engine (combined heat and power production) and natural gas fired heat-only boilers. Also an advanced control system, balancing maximum solar heat and maximum electricity sales. Solar coverage: 9%. Established in 2007.

Special remarks
A typical Danish system with a short-term heat store of 0.1 - 0.3 m^3 per m^2 solar collector covers 10 – 25% of the annual heat demand (ref. 4).

Some systems also have seasonal heat stores (cf. Technology element '70 Seasonal heat storage'). Under Danish climatic conditions, a district heating system, which is based entirely on solar energy, needs a seasonal store with a volume of about 4 m^3 per m^2 of solar collector, provided a heat pump is installed to empty the store. The below figure shows indicative data for the storage requirement as a function of solar heat coverage:



The heat coverage (horizontal axis) is the annual supply of solar heat in percent of total heat demand. The storage requirement (vertical axis) is expressed as store volume V (m^3) divided by solar collector area A (m^2) (ref. 4).

References

1. "Solar Water Heating Project Analysis", RETScreen International (www.retscreen.net), 2004.
2. "Solvarme – status og strategi" (Solar heating – status and strategy), Danish Energy Agency and Energinet.dk, May 2007.
3. Arcon Solvarme, 2008.
4. Planenergi, 2009.

Data sheet

Technology	Solar district heating					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Collector output, MWh/m2/year	0.5		0.5		A	1
Technical lifetime, years	30	30	30			3
Financial data						
Cost of solar collectors, pipes included, €/m2	227		156			1
Investment cost of total solar system, € pr MWh/year						
Without heat store	425	386	307		C	1
With diurnal heat store included	461	422	342		C	1
O&M costs, €/MWh	0.57	0.57	0.57		B+C	2

References:

1 Danish Energy Agency, 2010.

2 "Fact sheet on solar heat" (in Danish), www.solvarmecenter.dk; 2009.

3 "Life expectancy of solar collectors in solar district heating systems", Department of Civil Engineering, Technical University of Denmark, 2009.

Notes:

A The yield is very site-specific, depending much on the temperatures of the district heating network. The quoted yield is for a typical Danish installation without a heat pump to decrease the inlet temperature.

B Electricity consumption included; maintenance is around 0.14 €/MWh

C Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

50 PUMPED HYDRO STORAGE

Brief technology description
For bulk electricity storage in utility grids, pumped hydro power plants dominate, with approximately 100 GW in service around the globe (ref. 2).

A typical pumped hydro store (PHS) consists of two water reservoirs (lakes), tunnels that convey water from one reservoir to another, a reversible pump-turbine, a motor-generator, transformers, and transmission connection. The amount of stored electricity is proportional to the product of the volume of water and the height between the reservoirs. As an example, storing 1,000 MWh requires an elevation change of 300 m and a water volume of about 1.4 million m^3.

A new PHS, including dams, has high capital expenditures and a long construction time. If an existing hydro plant is extended to also be a PHS, the investment per installed MW is significantly lower and the construction time between 2 and 3 years.

With this technology electricity is basically stored as potential energy. Others ways of storing electricity as potential energy may have similar characteristics.

Input
Electricity

Output
Electricity

Typical capacities
PHS facilities are dependent on local geography and currently have capacities up to 1,000 MW. In addition to large variations in capacities PHS is also very divers regarding characteristics such as the discharge time, which is ranging from several hours to a few days. Efficiency typically is in the range of 70 % to 80 %, due to the losses in the process of pumping water up into the reservoirs.

Regulation ability
The primary intent of PHS is to provide peaking energy each day. However, their duty can be expanded to include ancillary service functions, such as frequency regulation in the generation mode. A variable-speed system design allows providing ancillary service capability in the pumping mode as well, which increases overall plant efficiency (ref. 2).

Advantages/disadvantages
The advantage of PHS is the large volumes compared to other storages e.g. various batteries. In addition PHS does not use fossil fuel such as e.g. CAES.

A disadvantage with PHS is the need for differences in height between the two reservoirs. When a new PHS is not built in connection with an existing hydropower plant there are also environmental concerns in flooding large areas.

Research and development

In the 1890's PHS was first used in Italy and Switzerland. After over 100 years of development PHS is considered to be a mature technology. New developments include seawater pumped hydro storage that was built in Japan in 1999 (Yanbaru, 30 MW). It is also technically possible to have a pumped underground storage by using flooded mine shafts or other cavities.

A new (2009) Danish concept is storing electricity as potential energy by elevating sand. The sand is lifted by pumping water into a balloon underneath the sand, and then lowered by taking the water out through the pump, now acting as a turbine.

Additional remarks

There are frequently several hydro power plants on the same river, and the operation of these plants is to some degree interlinked. The benefits of a new PHS therefore depend also on the existing hydropower infrastructure.

For new large hydropower plants in OECD countries, capital costs are about 2400 USD/kW and generating costs around 0.03-0.04 USD/kWh. The cost of pumped storage systems depends on their configuration and use. They may be up to twice as expensive as an equivalent unpumped hydropower system. Depending on cycling rates, their generating costs may be similar to those of unpumped systems (ref. 1).

References

1. "Energy technology perspectives 2008", International Energy Agency, 2008.
2. "Capturing Power Grid", IEEE Power & Energy Magazine, July/August 2009, http://www.electricitystorage.org/images/uploads/docs/captureGrid.pdf

Data sheet

Technology	Pumped hydro storage					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	10-1000	10-1000	10-1000	10-1000	A	2
Total efficiency (%) net	70 - 80	70 - 80	70 - 80	70 - 80	A	1
Technical lifetime (years)	50	50	50	50	A	1
Construction time (years)	2-3	2-3	2-3	2-3	A	
Financial data						
Investment, pump part (M€/MW)	0.6	0.6	0.6	0.6	B;C;A	1&2
Investment, total, greenfield plant (M€/MW)	< 4	< 4	< 4	< 4	D;A	4
Fixed O&M (€/MW/year) - 1-2% of investment	6-12,000	6-12,000	6-12,000	6-12,000	B;A	3
Variable O&M (€/MWh)	Depends on power price					

References:

1 BKK, presentation on Nygard Pumpekraftverk
2 Tonstad Pumpekraftverk, Sira-Kvina kraftselskap, 2002
3 BKK and Sira-Kvina
4 “Energy technology perspectives 2008”, International Energy Agency, 2008.

Notes:

A No significant technology advance or cost decrease is expected, since hydropower and water pumping are established technologies.
B Based on the September 2004 exchange rate of 1NOK = 0,12€
C Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying with a general inflation factor 1.2306
D Cf. paragraph 'Additional remarks' above.

51 COMPRESSED AIR ENERGY STORAGE

Brief technology description
Compressed air energy storage (CAES) is a technology for large-scale electricity storage. Air is compressed, preferably at times with low electricity prices, and injected into an underground store for later use. The underground geological formation may be a mine, a salt cavern, or a depleted gas well. When needed, the stored air is used together with gas to produce electricity.

In a conventional industrial gas turbine the compressor and turbine are operating on the same axis. The compression typically accounts for up to 2/3 of the total energy input. The generator output is therefore fairly small compared to the power generated by the turbine.

The basic concept of a CAES power plant is to split the gas turbine into a compressor unit for compressing the combustion air and an expansion turbine to generate mechanical power to drive a generator. This enables the utilization of the full capacity of the turbine, while leaving the compressor idle in periods of high demand.

CAES is characterized by being built in modules in form of a) compressors for air injection capacity; b) turbines/generator for withdrawal capacity; and c) underground storage for storage capacity. The storage can therefore be formed to a specific need, by altering one of these variables. This means that the storage is very flexible e.g. the storage capacity (can be doubled by creating another cavern) and the relationship between the loading and consuming time can also be easily altered. The numbers mentioned in the data sheets are only example of how the storage configuration can be.

Since a CAES plant uses fuel to heat air during the discharge generation cycle, it is not truly a ‘pure’ energy storage plant such as pumped hydro and batteries. In general, a CAES plant provides approximately 25-60% more electricity to the grid during on-peak times than it uses for compression during off-peak times (ref. 5).

Theoretically, all heat generated during compression could be recovered and used later to reheat the stored air during the generation cycle to eliminate the fuel consumption. However, this is rather costly and presently being researched only, and the table below therefore assumes no heat recovery.

For illustration, to generate 1 MWh electricity, the electricity needed for compression is 0.6 MWh, while 1.2 MWh of fuel is required for air heating and the turbine. Thus, the storage efficiency is
1 / (0.6 + 1.2) * 100 = 55%.

Input
Electricity, when the store is filled. Gas for air heating and turbine operation, when the store is emptied.

Output
Electricity and heat (optional, as is the case for SCGT or CCGT)

Typical capacities
There is no typical capacity. The two currently operating plants have generating capacities of 110 and 290 MW, but new plants can be both smaller and larger.

Regulation ability
A CAES plant will be able to generate at full capacity within 15 minutes from cold start.

Advantages/disadvantages
CAES is in addition to pumped hydro storage the only storage technology that currently is capable of operating over 100 MW for several hours. The potential production period is at any time limited by the actual filling level in storage.

CAES can be built in such a way that it also is possible to produce power by only using gas and no compressed air. In this situation the plant will be similar to a single cycle gas turbine.

The CAES positive environmental profile is the ability to store wind generated power from the time of generation to the time of consumption. On the negative side is that some energy is lost in this process and that fuel is used in the generation process.

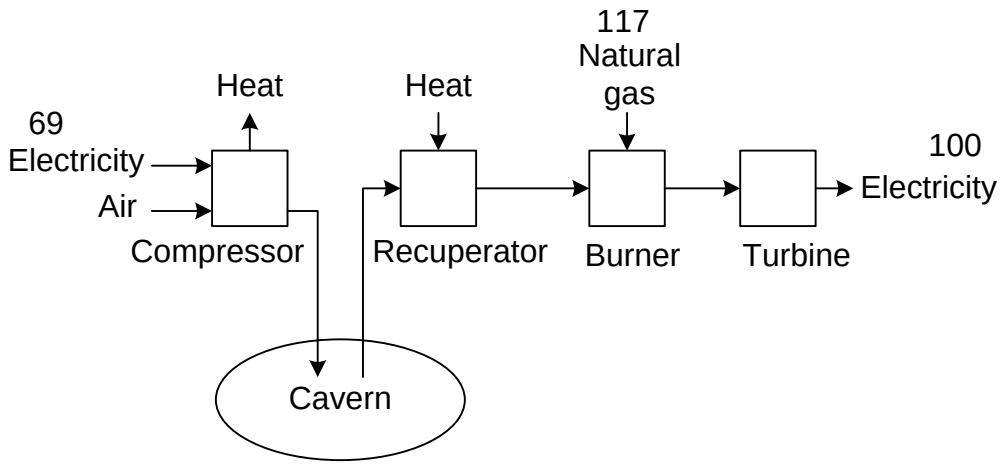
Research and development
World wide there have only been built two CAES plants so far. The CAES technology has potential for being improved and optimized. A major EU research project is currently being carried out with the aim of significantly improving the efficiency of future CAES power plants by using compression heat.

Examples of best available technology
- The CAES plant in Huntorf near Bremen, Germany, is operated by E.ON Kraftwerke. It was built in 1978 and has two caverns, each 155.000 m^3, 72 bar storage pressure. Original power output 290 MW; revamped to 321 MW in 2007. Storage efficiency 42% (ref. 6).
- The CAES plant in McIntosh, Alabama, USA operated by AEC (Alabama Electricity Corporation). It was commissioned in 1991 and has a maximum power output of 110 MW. Storage efficiency 54% (ref. 6).

Special remarks
Currently, the energy storage technology receiving the most attention for use in large-scale energy storage in U.S.A. is CAES, since the number of environmentally acceptable sites for future pumped hydroelectric facilities is very limited (ref. 8).

CAES needs to have an underground storage and salt caverns are most suitable, but natural aquifer structures and abandoned mines can also be used. This limits the location of CAES plants, there are however numerous salt deposits in Denmark, along the North Sea coast and some in the Baltic Sea coastal area.

The overall principle and energy balance of the newest plat in operation (McIntosh, USA) is shown below:



The air, which is compressed, gets warm and needs be cooled. Similarly, the high pressure air from the cavern is cooled, when the pressure is reduced, and therefore needs be heated before entering the burner. No external heat is needed, since heat from compression is re-used. The overall energy efficiency is 100 / (69 + 117) = 0.54.

Some of the generated electricity originates from natural gas. If this part is ignored, the storage efficiency, defined as the share of the electricity input, which is regained, is about 0.43 (ref. 7). This means that the 100 units of output electricity consist of 30 units from input electricity plus 70 units from natural gas.

References

1. Huntorf CAES: More than 20 Years of Successful Operation, by Fritz Crotogino KBB GmbH, Hannover, Germany and Klaus-Uwe Mohmeyer and Dr. Roland Scharf E.ON Kraftwerke Bremen, Germany.
2. U.S. Department of Energy, Energy Efficiency and Renewable Energy: Renewable energy Technology Characterizations, December 1997
3. ESA, Electricity Storage Association, www.electricitystorage.org
4. CAES development company, www.caes.net
5. EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications, EPRI, 2003
6. "30 years compressed air energy storage plant Huntorf – Experiences and outlook", presentation by P. Radgen, E.ON Energie, at the "Third International Renewable Energy Storage Conference (IRES 2008)", Berlin, November 2008.
7. "CAES – Compressed air electricity storage", presentation by B. Elmegaard, Technical University of Denmark, January 2009.
8. "Bottling Electricity: Storage as a strategic tool for managing variability and capacity concerns in the modern grid", Electricity Advisory Committee, December 2008, http://www.oe.energy.gov/DocumentsandMedia/final-energy-storage_12-16-08.pdf

Data sheet

Technology	Compressed Air Energy Storage (CAES)					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	100 - 350					
Electricity efficiency (%) net	60	71	71	71	A	1
Time for warm start-up (hours)	0	0	0	0		2
Starting reliability (%)	99	99	99	99		3
Availability (%)	95	95	95	95		3
Technical lifetime (years)	30	30	30	30		2
Construction time (years)	3	3	3	3		2
Environment						
NO_X (kg per GJ fuel)	< 0,006	< 0,002	< 0,002	< 0,002	B	4
CH_4 (kg per GJ fuel)	0.0015	0.0015	0.0015	0.0015		4
N_2O (kg per GJ fuel)	0.0022					4
Financial data						
Investment storage, € per kWh storage volume	240	246	246	246	C+D	5
Investment converter, € per kW output capacity	2000	1970	1970	1970	C+D	5
Fixed O&M (€/MW/year)	< 14,000	< 14,000	< 14,000	< 14,000	C+E	3
Variable O&M (€/MW/year)	-	-			F	
Regulation ability						
Fast reserve (MW per 15 minutes)	100%	100%	100%	100%		1

References:

1 "30 years compressed air energy storage plant Huntorf – Experiences and outlook", presentation by P. Radgen, E.ON Energie, at the "Third International Renewable Energy Storage Conference (IRES 2008)",

2 KBB GmbH (a Schlumberger company),

3 EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications, EPRI, 2003

4 It is estimated that emissions will be similar to Gasturbine single cycle so data is copied from technology sheet no. 04.

5 "Economical and technical evaluation of energy storage systems", presentation by J. Oberschmidt & M. Klobasa, Fraunhofer Institut, at the "Third International Renewable Energy Storage Conference (IRES 2008)", Berlin, November 2008.

Notes:

A The 2010 efficiency data is for the two plants in operation. Efficiency improvements are based on a concrete case study.

B NOx emission today 25 ppm, 2010-15 < 9 ppm and 2020-30 < 1 ppm.

C No significant cost decrease is expected, since all equipments are established technologies.

D The two investment components shall be added, cf. paragraph 1.3 in the introductive chapter.

E Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying with a general inflation factor 1.2306

F Variable O&M costs depend mainly on power and gas consumption and the specific fuel costs.

52 BATTERIES

Brief technology description
There are several technologies available or being developed for storing electricity. Below is a classification of a selection of these technologies regarding their capacities and discharge times.

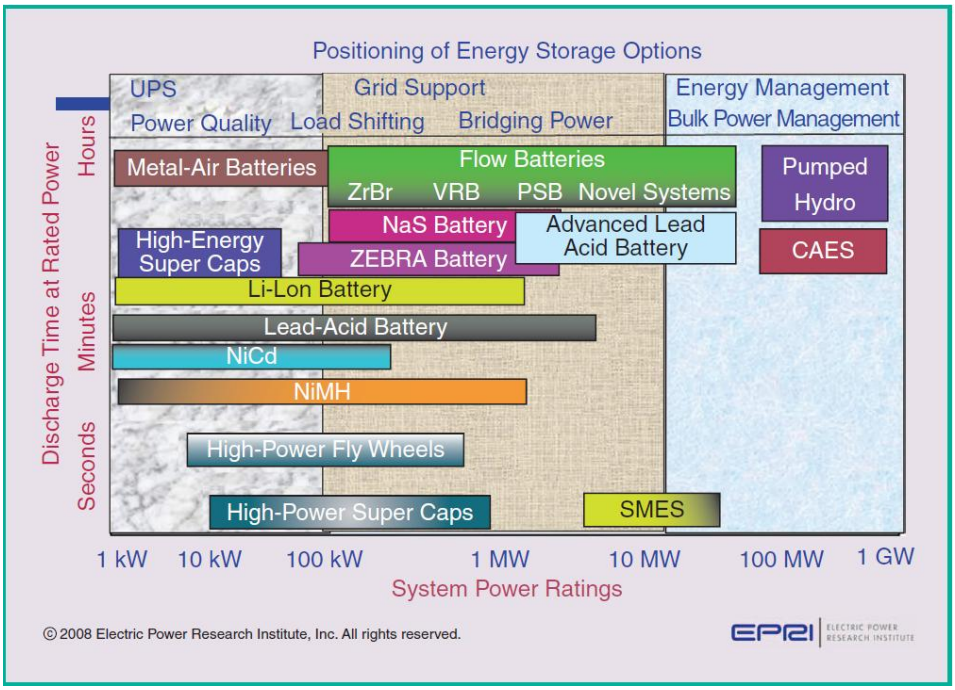


Figure: Storage technology comparison by application (power level) and storage time (ref. 3). UPS: Uninterruptible Power Supply (e.g. backup for data centres to support the Internet and communication centres).

The battery technology with the broadest base of applications today is the lithium-ion battery, used e.g. in laptop computers and electric vehicles. The ability of lithium-ion batteries to economically serve electric utility applications has not yet been demonstrated, except for some ancillary services provisions to independent system operators (ref. 4).

Three main battery types are most relevant for large-scale electricity storage:

- Advanced lead acid batteries
- NaS (Sodium Sulphur) batteries
- Flow batteries, in particular:
    - Vanadium Redox (VRB)
    - Zinc-bromine (ZnBr)

The lead-acid battery is one of the oldest and most developed battery technologies. A lead-acid battery is an electrical storage device that uses a combination of lead plates or grids and an electrolyte

consisting of a diluted sulphuric acid to convert electrical energy into potential chemical energy and back again.

The sodium sulphur (NaS) battery is a high-temperature (about 300 °C) battery system that consists of a molten sulphur positive electrode and a molten sodium negative electrode separated by a solid ceramic electrolyte. During discharge, positive sodium ions flow through the electrolyte and electrons flow in the external circuit of the battery, producing about 2 V. This process is reversible (ref. 3).

Flow batteries utilize an active element in a liquid electrolyte that is pumped through a membrane similar to a fuel cell to produce an electrical current. The system's power rating is determined by the size and number of membranes, and the runtime (hours) is based on the volume of electrolyte pumped through the membranes. Pumping in one direction produces power from the battery, and reversing the flow charges the system.

The Vanadium redox battery (VRB) is based on vanadium as the only element, and is based on the reduction and oxidation of the different ionic forms of Vanadium. Energy can be stored indefinitely in a liquid – very low self-discharge.

The Zinc-bromine (ZnBr) battery is based on cells with two different electrolytes flowing past carbon-plastic composite electrodes in two compartments separated by a microporous polyolefin membrane.

For batteries to be practically applied in the utility grid, reliable power conversion systems (PCSs) that convert AC power to battery DC and back to AC are needed.

Typical capacities
See figure on previous page.

Input
Electricity

Output
Electricity.
Some of the electricity losses may be regained as useful heat. However, a heat pump may be necessary to produce valuable heat.

Regulation ability
The potential benefits for electricity systems are:

- Deferred or avoided substation upgrade
- Energy cost savings, e.g. reduce peak energy generation/purchases or shift off-peak wind generation to peak
- Transmission and/or generation capacity reduction credit
- Regulation control and black start

Advantages/disadvantages
Advantages of the Vanadium Redox (VRB) system is a high-energy efficiency of over 75% (AC to AC) and over 85% (DC to DC); a very low self discharge; storage capacity can be increased by increasing electrolyte volume (no change to battery cell-stacks); the lifetime charge-discharge cycle is over 13,000 cycles without need for membrane replacement. The battery has a charge/discharge window of 1 to 1.

The strengths of the NaS battery are also the high average DC energy efficiency (charging/ discharging) of 85%, its relative long-term durability of 15 years and assumed specification of 2,500 cycles, and a high energy density i.e. reduced space requirements.

Research and development
The basic principals behind the NaS battery were discovered in the 1960s by the Ford Motor Company. NGK of Japan began research in NAS batteries in 1987, began testing of prototypes for commercial use at the Tokyo Electric Power in 1992 and in Japan are currently 19 sites totalling 52 MW, mainly for demonstration purposes. The major stakeholders are NGK (producer) and Tokyo Electricity Power (alliance with NGK).

Early work on VRB was undertaken by NASA in the 1970s. Currently the major stakeholders and developers are VRB Power Systems (Canada), Sumitomo Electric Industries (Japan) and Squirrel Holdings (Thailand).

Examples of best available technology

VRB

- PacifiCorp installation of 250 kW, 8 hours (2 MWh) battery completed in February 2004, which also should be used for peak shaving.
- Hydro Tasmania has a 200 kW, 4 hours (0.8 MWh) battery completed in November 2003, in connection with wind turbines on Kings Island.
- Tottori SANYO Electric Co. has a 1500 kW and 1500 kWh battery for Peak shaving.

NaS

- The NaS battery technology for large-scale applications was perfected in Japan. There are 190 battery systems in service in Japan, totalling more than 270 MW of capacity with stored energy suitable for six hours of daily peak shaving. The largest single NaS battery installation is a 34 MW, 245 MWh system for wind power stabilization in northern Japan (ref. 3).
- American Electric Power is deploying a 5.0 MW NaS battery to solve a transmission issue in southern Texas (ref. 4).

ZnBr

The Zinc-bromine battery is currently in use in the United States (ref. 4).

Special remarks

The figure below shows the investment costs of various technologies for electricity storage:

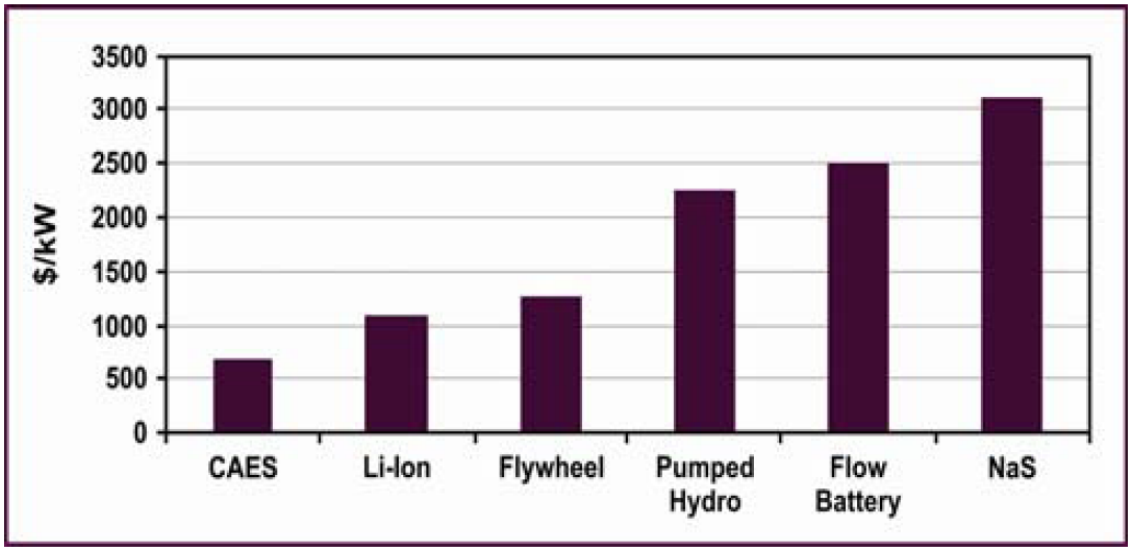


Figure: Energy storage technologies cost estimates. The CAES technology (cf. technology element 41) also requires fuel costs for discharging, which are not captured in the figure. If the system operated on compressed air alone, the costs per kilowatt (kW) would be approximately three times greater (ref. 4).

The RD&D in batteries has increased dramatically in recent years, primarily due to the huge political focus and demand for electric vehicles. This development may yield a positive spin-off for large stationary batteries, in terms of efficiencies, technical life and cost. Thus, the cost forecasts in the tables below may be somewhat to the conservative side.

References

1. EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications, EPRI, 2003
2. Electricity Storage Association, http://www.electricitystorage.org/tech/technologies_comparisons_ratings.htm
3. "Capturing Power Grid", IEEE Power & Energy Magazine, July/August 2009, http://www.electricitystorage.org/images/uploads/docs/captureGrid.pdf
4. "Bottling Electricity: Storage as a strategic tool for managing variability and capacity concerns in the modern grid", Electricity Advisory Committee, December 2008, http://www.oe.energy.gov/DocumentsandMedia/final-energy-storage_12-16-08.pdf

Data sheets

The investment costs of the two selected batteries are stated in different terms:

- The total investment of the NAS battery has been converted to specific cost in two different ways, by dividing by the stored amount of energy (€/MWh) and by the generating capacity (€/MW). This is due to lack of data for the NAS battery. The two alternative ways shall not be added.
- The investment of the VRB battery is separated into two components, which shall be added (through the discharge time per cycle): 1) The equipment, which is primarily determined by the amount of energy stored (i.e. the battery itself); and 2) The equipment, which determines how much power the system can deliver (i.e. converter).

Cf. further explanation in paragraph 1.3.

Technology	**Sodium Sulphur (NaS)**					
	2015	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Storage capacity (MWh)	100	100	100			2
Generating capacity for one battery (MW)	10	10	10			2
Charge-discharge ratio	2:1				A	2
Cell efficiency (%)						
System efficiency (%), AC to AC, net	85%					3
Lifetime in full charge-discharge cycles	2500					2
Technical lifetime (years)	15	15	15			5
Construction time (months)	6-8					1
Financial data						
Specific investment, storage capacity (k€/MWh)	210-940	136	136		D	7;4;4
or specific investment, output capacity (M€/MW)	1.8-2.6	1.7	1.7		D	4+5+6;4,4
Fixed O&M (€/MW/year)	51000	51000	51000		D	4
- do -	7100				D	5
Variable O&M (€/MWh)	5.3	5.3	5.3		B+D	4
- do -	16				C+D	5

References:

1 Commercial Deployment of the NaS Battery in Japan, by Hyogo Takami, Tokyo Electric Power Company and Toyoo Takayama, NGK Insulators, Ltd.
2 Electric energy storage solution group, R&D center, engineering R&D division, Tokyo electric power company (e-mail)
3 NAS battery energy storage system for power quality support in Malaysia, Siam, Hyogo Takami, (TEPCO)
4 EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications, EPRI, 2003.
5 "Economic valuation of energy storage for utility.scale applæications", Dan Mears, Technology Insigths (Canada) at Workshop on Electricity Storage, Toronto, June 18 2008.
6 Information from NGK Insulators Ltd. (www.ngk.co.jp/english), Japan, to Danish Energy Authority, September 2008
7 Electricity Storage Association, California, http://electricitystorage.org/tech/technologies_comparisons_capitalcost.htm

Notes:

A Number of hours it takes to charge the battery for having one hour to discharge the battery.
B Based on 2500 operating hours a year
C Assuming 1000 hours/year. If the battery is used for regulation control and black start, the variable O&M is only 3
D Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

The number of charge-discharge cycles and thus the O&M costs strongly depend on how a battery is applied, e.g. for deferring a substation upgrade, for energy cost savings (shift off-peak generation to peak), transmission and generation capacity reduction, or regulation control and black start service. The above table therefore gives two sets of O&M costs.

Technology	**Vanadium Redox (VRB)**					
	2015	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Storage capacity (MWh)						
Generating capacity for one unit (MW)	10	10	10			1
System efficiency (%), DC to DC, net	80					3
System efficiency (%), AC to AC, net	70					4
Lifetime in full charge-discharge cycles	13000					1
Construction time (months)	6-8					1
Financial data						
Investment storage, k€ per MWh storage volume	70	51	51	51	C	4
Investment converter, M€ per MW output capacity	1.5	1.1	1.1	1.1	C	4
Fixed O&M (€/MW/year)	54,000	54,000	54,000		A	2
Variable O&M (€/MWh)	2.8	2.8	2.8		A;B	2

References:

1 VRB Power Systems Incorporated, an electrochemical Energy Storage Company, Executive Summary

2 EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications, EPRI, 2003.

3 "Vanadium redox flow battery", presentation by M. Schreiber, Cellstrom, at the "Third International Renewable Energy Storage Conference (IRES 2008)", Berlin, November 2008

4 "Economical and technical evaluation of energy storage systems", presentation by J. Oberschmidt & M. Klobasa, Fraunhofer Institut, at the "Third International Renewable Energy Storage Conference (IRES 2008)", Berlin, November 2008

Notes:

A Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying with a general inflation factor 1.2306

B Based on 2500 operating hours a year

C A 27% cost decrease for the mature technology is expected (ref.2).

60 SEASONAL HEAT STORAGE

Brief technology description
This technology sheet addresses different options for long-term (seasonal) heat storage for district heating systems.

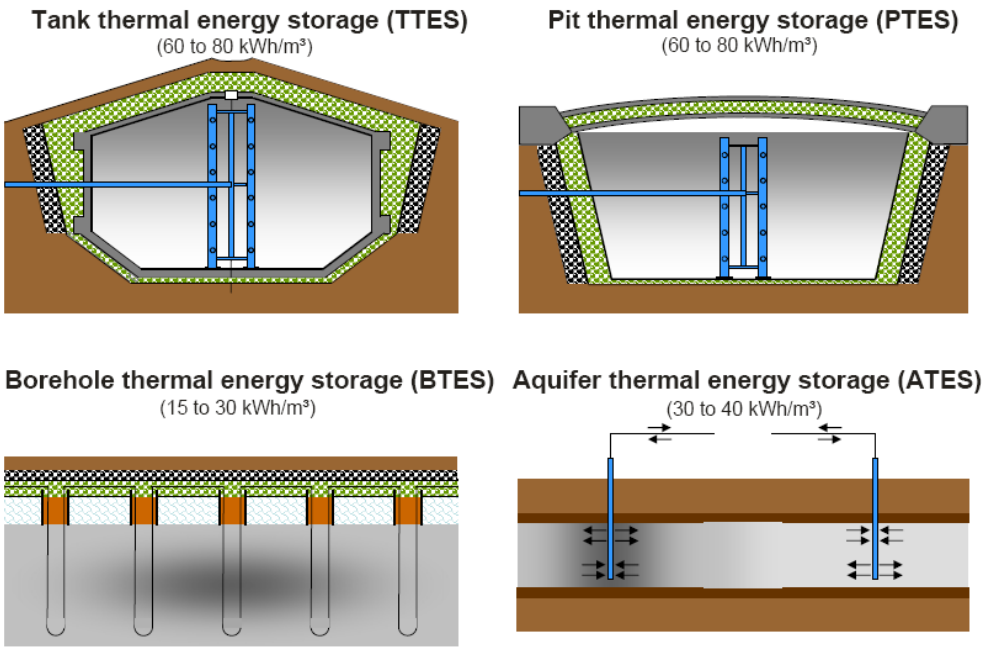


Figure 1: Seasonal thermal energy storage – concepts (ref. 2).

A hot-water tank is similar to the water tanks used for short-term (diurnal) heat storage, only bigger. They are used for solar heating systems in e.g. Germany, where the biggest tank is 12.000 m^3 (ref. 2).

The water pit is the most commonly used technology in Denmark, since initial demonstrations showed that this is the cheapest solution for large volumes (ref. 1 and 4). A water pit is essentially a hole in the ground lined by a water-proof membrane, filled with water and covered by a floating and insulating lid. The excavated earth may be used as a dam surrounding the hole, thus increasing the water depth.

When storing hot and/or cold water in natural underground aquifers, direct heat exchange is taking place through vertical wells, typical one centre well and a number of peripheral wells. Several aquifer stores are being operated together with heat pumps in Holland and Sweden, for space cooling during summer and heating during winter. China has a long tradition of cold water storage in aquifers. The chemical composition of the aquifer and natural groundwater flow may negatively influence the

performance. However, the flow can be managed by extra wells outside the storage area. Aquifer storage is the cheapest technique for huge low-temperature volumes, when it can be mastered (ref. 3).

Tubes in boreholes (duct storage) used with heat pumps is common in several countries. A typical store operates at low temperatures (0 to 30 °C). The storage efficiency can reach 90 to 100% when the store is operating around the average natural temperature of the ground (ref. 3), and there is no strong natural groundwater flow.

Using tubes in gravel and sand is a combination of the water pit and the borehole store. Using gravel and sand as storage media increases the storage capacity (kWh/m^3).

Input
Heat from any heat source, e.g. solar collectors.

Output
District heat.

The average heat loss depends on several parameters. A characteristic figure for the ratio of the heat losses to the amount of stored energy is the surface/volume ratio of the store. A small store with a volume of e.g. 20 m^3 has a surface to volume ratio that is eight times the ratio of a store with 10,000 m^3. Hence, the heat losses referred to the stored energy are eight times higher for the small store than for the large one.

Another important issue is, whether a heat pump is used to cool the stored water. This will decrease the annual heat losses substantially.

The heat losses from a pit store are larger during the first four years than afterwards, as the surrounding soil needs be heated.

Research and development
Major challenges for water pits are:

- Reliable and maintenance-free pits;
- Lower costs;
- Membranes, which can withstand 95 ^{o}C on a long term basis.

Examples of best available technologies
Water pits: Marstal (www.solarmarstal.dk), Dronninglund (www.planenergi.dk).
Gravel storage: Marstal (ref. 1)
Tanks: Hannover and Munich (www.solites.de)

Additional remarks
Heat stores are characterized by a considerable economy of scale:

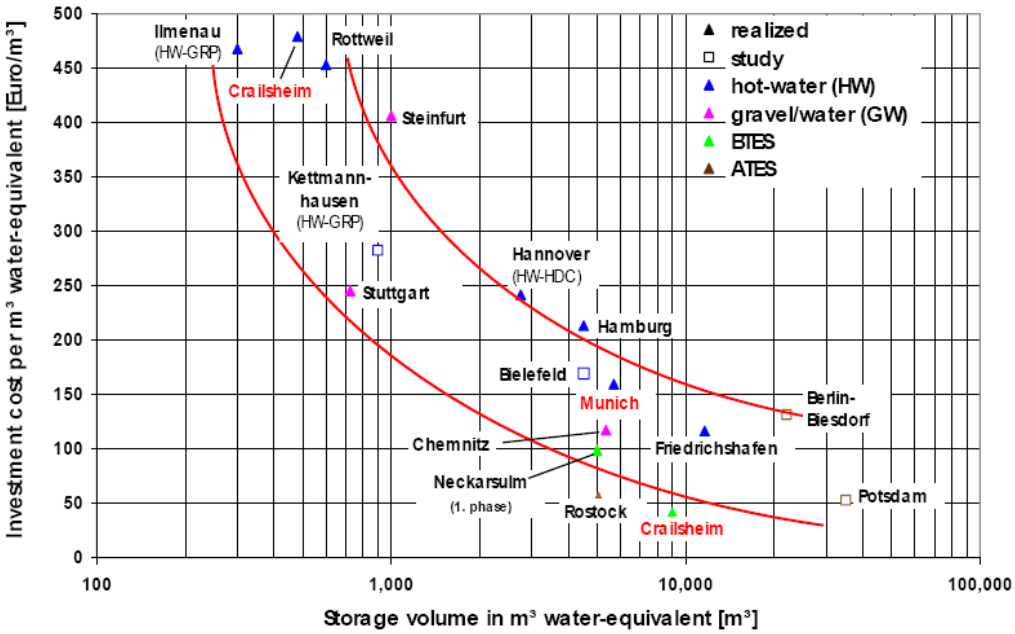


Figure 2: Investment cost of seasonal heat stores in Germany (ref. 2). The strong cost degression with increasing volume is obvious. GRP: Glass-fiber reinforced plastic. HDC: High-density concrete. ATES: Aquifer Thermal Energy Storage. BTES: Borehole Thermal Energy Storage.

The most expensive part of a pit heat storage is the cover. Distribution of investment cost for a 60,000 m^3 pit, which is being established 2009-10 in Dronninglund, Denmark (ref. 4):

	€/m3
Excavation of earth	3.2
Membrane work	5.7
Cover	2.8
Cover membrane (roof foil)	6.0
Drainage system	0.27
Mineral wool	1.5
Manhole	0.13
Total direct costs	20
Other costs (heat exchanger, connecting pipes, planning, administration etc.)	14
Overall cost	34

There is almost no economy-of-scale for store volumes above 50,000 m^3. The marginal investment cost for increasing the volume is about 20 €/m^3 (ref. 4). Thus, the investment cost for 100,000 m^3 store would be approx. 27 €/m^3.

The investment cost of a 5,700 m^3 storage tank, established in Munich, Germany, 2006, was about 160 €/m3 (ref. 5).

Under Danish climatic conditions seasonal storage of solar heat typically requires 0.5-2 m^3 store volume per m^2 solar collector, with solar heat contributing 20-40% of the total heat load (cf. technology element '56 Solar district heating'). For solar heat only systems, the store volume needs be about 4 m^3 per m^2.

References

1. "Seasonal heat storages in district heating networks", Ellehauge & Kildemoes and Cowi, July 2007. A project (Preheat) funded by Intelligent Energy – Europe and the Danish systems operator Energinet.dk.
2. Dirk Mangold: "Seasonal Heat Storage. Pilot projects and experiences in Germany" (www.solites.de). Presentation at the PREHEAT Symposium at Intersolar 2007, Freiburg, Germany, June 2007.
3. "Heat storage technologies". Report, June 2007, from the PREHEAT project, funded by the Intelligent Energy – Europe programme (www.preheat.org).
4. Planenergi (Danish company; www.planenergi.dk), which has been involved in most pit heat stores in Denmark, and which is installing (2009-10) a 60,000 m^3 pit store in Dronninglund, Denmark.
5. "Technologies for thermal energy storage", presentation by P. Schossig, Fraunhofer Institut, Solare Energiesysteme, at the "Third International Renewable Energy Storage Conference (IRES 2008)", Berlin, November 2008.

Data sheet

Technology	Seasonal heat storage in water pits					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Store volume (m3)	60000					
Storage capacity, kWh/m3	60-80					2
Efficiency, %	80-95				A	3
Construction time (years)	0.5	0.5	0.5	0.5		3
Technical lifetime (years)	20	20	20	20	B	3
Financial data						
Specific investment costs (€ per m3)	35	35	34	30	C	1;3;3;3
Electricity consumption (MWh/year)	40				D	3
O&M (% of investment per year)	0.7					3

References:

1 "Seasonal heat storages in district heating networks", Ellehauge & Kildemoes and Cowi, July 2007. A project (Preheat) funded by Intelligent Energy – Europe and the Danish systems operator

2 Dirk Mangold: "Seasonal Heat Storage. Pilot projects and experiences in Germany". Presentation at the PREHEAT Symposium at Intersolar 2007, Freiburg, Germany, June 2007.

3 Planenergi (Danish company; www.planenergi.dk), which in 2010 is installing a 60,000 m3 pit store in Northern Jutland.

Notes:

A The storage loss depends on several parameters, such as store volume, insulation, whether a heat pump is part of the system etc. The stated interval covers a large store, storage temperature 85-90 C, without (80%) and with (95%) a heatpump to discharge the store.

B The most critical part is the cover. The technical lifetime depends much on the water temperature. The lifetime of the store may be extended by reinvesting in a new cover.

C 2010: Budget cost for a 60,000 m3 pit. The cost development assumes a 10-20% reduction from 2020 to 2050, caused by replication of pits, pipes, pumps, heat exchangers and control system. For other store volumes, please refer to paragraph 'Additional remarks' above.

D Electricity for internal pumps etc. only. If a heat pump is used, the drive electricity shall be added.

E Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

61 LARGE-SCALE HOT WATER TANKS

Brief technology description

Thermal storage options can be split into four physically different technologies:

1. Sensible stores, which use the heat capacity of the storage material – mainly water for its high specific heat content per volume, low cost and non-toxic medium.
2. Latent stores, which make use of the storage material's latent heat during a solid/liquid phase change at a constant temperature.
3. Sorption stores, which use the heat of ad- or absorption of a pair of materials such as zeolite-water (adsorption) or water-lithium bromide (absorption).
4. Chemical stores, which use the heat stored in a reversible chemical reaction.

The market is dominated by hot water storage vessels due to the qualities, the cost, the simplicity and the versatility of water as a storage medium.

Sensible stores may be constructed as steel, concrete or glass-fibre reinforced plastic tanks.

Steel tanks for hot water storage are a well established technology. Typically, a steel tank for district heating applications is insulated with about 2x150 mm insulation (mineral wool), but for long-term storage, such as solar heat, 3x150 mm may be better (ref. 6).

In recent decades steel tanks have been used as short-term storage in connection with combined heat and power production and for almost all biomass heating plants in Denmark to control operation and to reduce emissions.

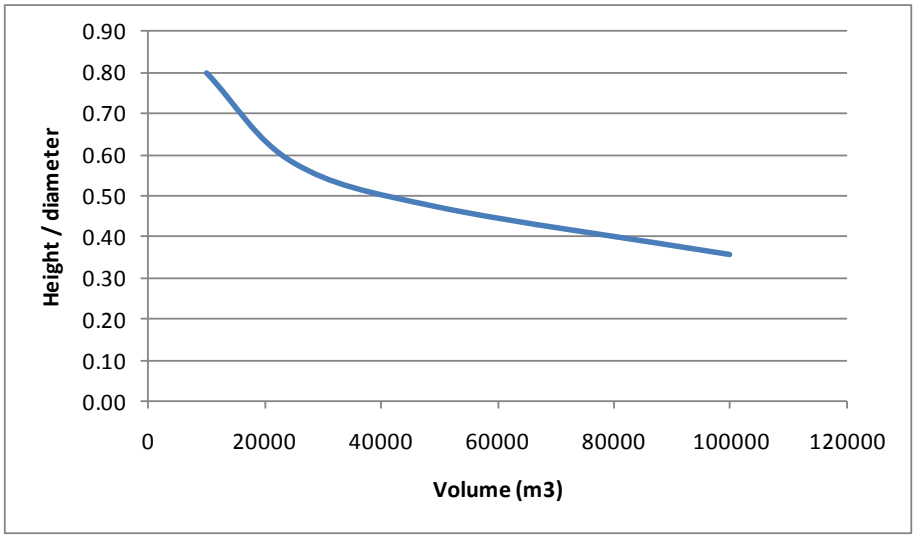
Input
Hot water.

Output
Hot water.

Typical capacities
In Denmark, a combined heat and power plant typically operates at full capacity during the peak- and high-load hours of the electricity market, about 75 hours a week. Still, the plants often have heat storage capacity to cover the heat load for a full week during the cold season (ref. 5). The largest tanks are above 50.000 m^3.

For a biomass plant a typical capacity would be 10 – 12 hours full load at peak demand on a cold Winter day (service time needed for small repairs) or 72 hours on Summer load to allow for weekend stop and/or boiler inspection (ref. 6).

Optimal height/diameter relation (minimum heat loss and cheapest steel structure) for steel tanks (ref. 4):



The energy content of heated water (in MJ per m^3) is 4.187 times the temperature difference, so with a temperature difference of 40 ^oC, the storage capacity is 167 MJ/m^3. For illustration, to deliver a heat output of 1 MJ/s for a full week, you need a tank of about 3000 m^3.

Advantages/disadvantages

The most cost effective way of storing low (0 - 20ºC) to medium (20 - 100ºC) temperature heat is water, because it is relatively cheap and convenient material. Furthermore water has, compared to other common storage materials, a very high specific heat capacity as well as a very high volumetric heat capacity, which is in particular important for compact storage systems.

The major challenges with water storage are that the tanks are difficult to insulate properly and that they require substantial volume. Development to use chemical processes for heat storage is therefore ongoing.

Additional remarks

The heat loss (in J/s) can be determined by:

$$Q = k \cdot (T_{ext} - T_{st}) \cdot V$$

where

k is the heat loss coefficient (J/s per ^oC and per m^3),
T_{ext} is the temperature outside the store (^oC),
T_{st} is the average inside temperature of the store (^oC),
and V is the store volume (m^3).

For a store insulated by 50 cm mineral wool, k is typically 0.16 J/s/^{o}C/m^{3}. Thus, a store of 10,000 m^{3} and an average temperature difference of 85 ^{o}C (e.g. 90 – 5 ^{o}C), looses 136 kJ/s. For a storage cycle of one week, the total loss would be 82 GJ. If the store operates between 90 ^{o}C and 50 ^{o}C, the storage capacity is 1675 GJ, and the loss therefore amounts to 5 % of the stored heat.

With an insulation of only 20 cm mineral wool k would be around 0.16 J/s/^{o}C/m^{3}.

Prices of Danish steel tanks used in district heating systems (ref. 1 and 4) and German tanks (ref. 2; concrete tanks):

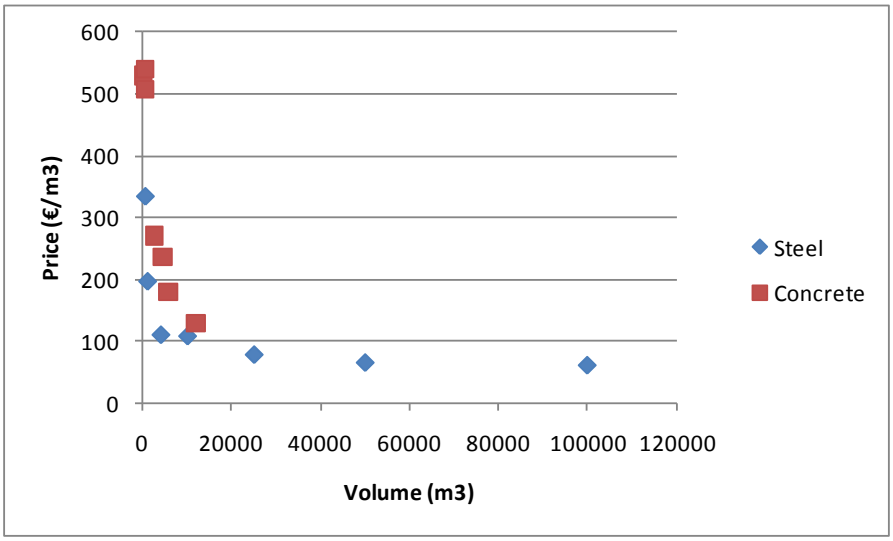
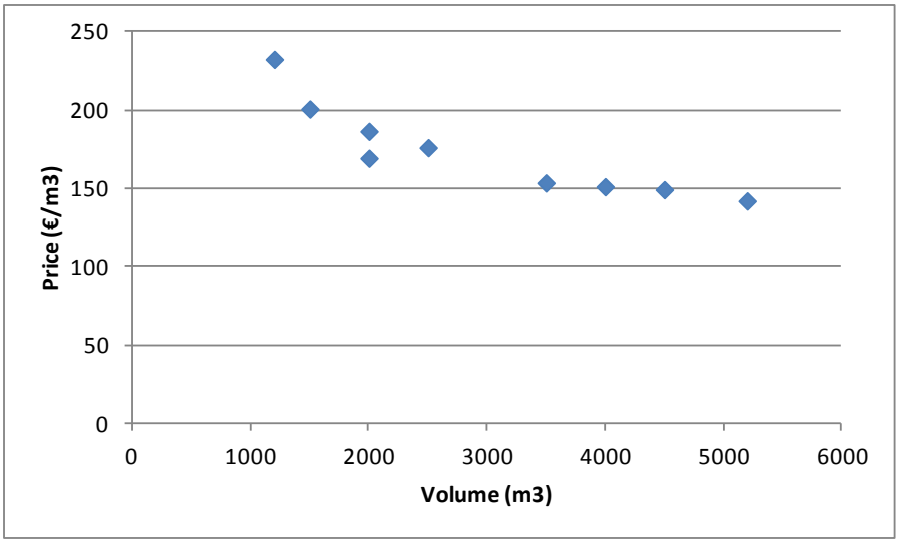


Figure 1: Price in €/m^{3} (2011 price level) as function of storage volume in m^{3}.

Recent prices for steel tanks used in small-medium Danish district heating systems are shown in Figure 2 (ref. 6):



The cost breakdown for a 5700 m^3 concrete hot water store built in Munich, Germany, in 2007 was (ref. 2):

Ground work	12%
Static construction	38%
Stainless steel liner	20%
Insulation	14%
Charging/discharging device	8%
Connection to heating plant	5%
Others	3%

References

1. "Solar heat storages in district heating networks", Ellehauge & Kildemoes and COWI, July 2007.
2. Dirk Mangold: "Seasonal Heat Storage. Pilot projects and experiences in Germany" (www.solites.de). Presentation at the PREHEAT Symposium at Intersolar 2007, Freiburg, Germany, June 2007.
3. "Solvarme – status og strategi". Energistyrelsen og Energinet.dk, maj 2007.
4. "Sæsonvarmelagring i store ståltanke" (seasonal heat storage in large steel vessels), Test Station for Solar Energy, Denmark, March, 1993.
5. "Bedre integration af vind: Analyse af markedsdata for vindkraft, decentral kraftvarme m.m." (Improved integration of wind energy: Analysis of market data on wind power, combined heat and power production etc.), Ea Energy Analyses, Copenhagen, September 2009.
6. Danish District Heating Association, January 2012.

Data sheet

Technology	Large steel tanks for heat storage					
	2010	2020	2030	2050	Note	Ref
Energy/technical data						
Storage capacity, kWh/m3	60-80					1
Efficiency, %	95				A	
Environment						
Financial data						
Specific investment costs (€ per m3)	160-260				B	2
O&M						

References:

1 Dirk Mangold: "Seasonal Heat Storage. Pilot projects and experiences in Germany". Presentation at the PREHEAT Symposium at Intersolar 2007, Freiburg, Germany, June 2007.

2 "Heat storage technologies". Report, June 2007, from the PREHEAT project, funded by the Intelligent Energy – Europe programme (www.preheat.org).

Notes:

A This is an example: A 10,000 m3 store operating between 90 and 50 C, an outdoor temperature of 5 C, and a storage cycle of one week. Cf. description above under 'Additional remarks'.

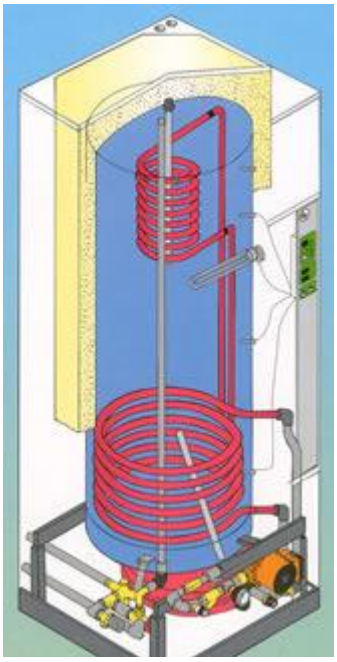
B Store volume 10,000 m3.

62 SMALL-SCALE HOT WATER TANKS

Brief technology description

Hot water storage vessels in private homes are used for different purposes:

- Domestic hot water; to ensure sufficient flow for high demands such as showers and filling bath tubs. Basically a drum filled with water and equipped with a heating mechanism on the bottom or inside.
- Space heating; to function as ‘peak shavers’ for district heating or solar heating.
- Shift load storage to capture the cheaper, off-peak electricity and using it at other times, effectively shifting portions of peak load to off-peak hours. Reshaping the load curve improves the utility's capacity factor and, by extension, its financial health.



For solar domestic hot water, the heat exchanger from the solar collectors is usually placed in the bottom of the store, cf. the lower coil in figure 1. Often, an extra coil is placed in the top of the store to raise the temperature by an additional heat source, when needed.

For shift load storage there is no need to have heat exchanger coils, if for example the store is a component in a closed circuit with a heat pump.

In Denmark, hot water vessels are typically made in steel, corrosion protected by enamel and anode. Other countries also use stainless steel, which is generally found too costly in Denmark (ref. 1).

Figure 1: Typical domestic hot water store used for solar heating (ref. 1).

Input
Heat

Output
Hot water

Typical capacities
To store domestic hot water, the volume is often 100 - 150 litres for a single-family dwelling.

For solar water heaters, with no seasonal storage, the store volume needs be around 50-65 litres per m^2 solar collector (ref. 1).

If a large volume is needed, the limit is often determined by the available space, e.g. in the laundry room of the dwelling. A cupboard solution, 60 by 60 cm horizontal and 2+ metres high, has a water volume of approx. 400 litres (ref. 5).

The energy content of heated water (in kJ per litre) is 4.187 times the temperature difference, so with a temperature difference of 40 ^{o}C, the storage capacity is 167 kJ/litre. For illustration, to deliver a heat output of 1 kJ/s for a full week, you need a tank of about 3000 litres.

Regulation ability

The Danish electricity transmission and systems operator Energinet.dk has funded a demonstration project ('From Wind Power to Heat Pumps', 2010-12) involving 300 homes with heat pumps to test how these can be used to create dynamic demand, responding to electricity prices or serving the electricity distribution companies in providing regulation power to the overall system. As part of the project, Energinet.dk has analysed the potential for operating heat pumps with increased flexibility by means of hot water stores (ref. 4).

Under Danish conditions, the potential benefit from full utilization of flexible electricity demand is 1.35 – 2.90 €cents/kWh. If an owner of a heat pump, with an annual electricity demand of 6000 kWh/year, received the entire benefit, this gives an annual saving of 80 – 140 €/year. However, a heat pump has very little flexibility during the coldest months, when it is operated next to full load. Therefore, moving electricity demand within 24 hours at anytime during the year will realistically yield a benefit of less than 40 €/year (ref. 4).

A hot water store of 400 litres enables disconnecting a heat pump 1 – 2 hours during cold days, in average up to 4 hours, without significantly compromising the indoor temperature. A cheap store, with no heat exchanger, costs 540 – 670 € (ref. 5). Thus, the solution is not very attractive for home owners, unless more of the societal benefits are transferred to the home owners through price mechanisms or other incentives.

Advantages/disadvantages

Tanks are ideally suited for water storage since they are cheap and easy to produce (for example, 50-1000 liter tanks are built by millions each year for the domestic and international market).

The major challenges with water stores are that they are difficult to insulate sufficiently, and that they take much space. Therefore, developers are searching for feasible stores using chemical processes.

Environment

Electricity is produced and delivered more efficiently during off-peak hours than during on-peak periods. The reduction in source fuel normally results in a reduction of greenhouse-gas emissions produced by the power plant

Additional remarks

The heat loss coefficient for a 200 liters store insulated by 10 cm mineral wool is about 1.1 J/s per ^{o}C, and about 2.0 J/s per ^{o}C, if the volume is 600 liters. The coefficients are twice as big, if the insulation is

only 5 cm. Thus, a 600 liters store, insulated by 10 cm mineral wool, and storing water at 40 ^{o}C above an average room temperature of 20 ^{o}C looses 2.5 GJ/year.

The cost of a hot water store is almost a linear function of the volume (ref. 2). The figure below shows the nominal prices of some hot water stores in Denmark, including heat exchanger coil and excluding installation:

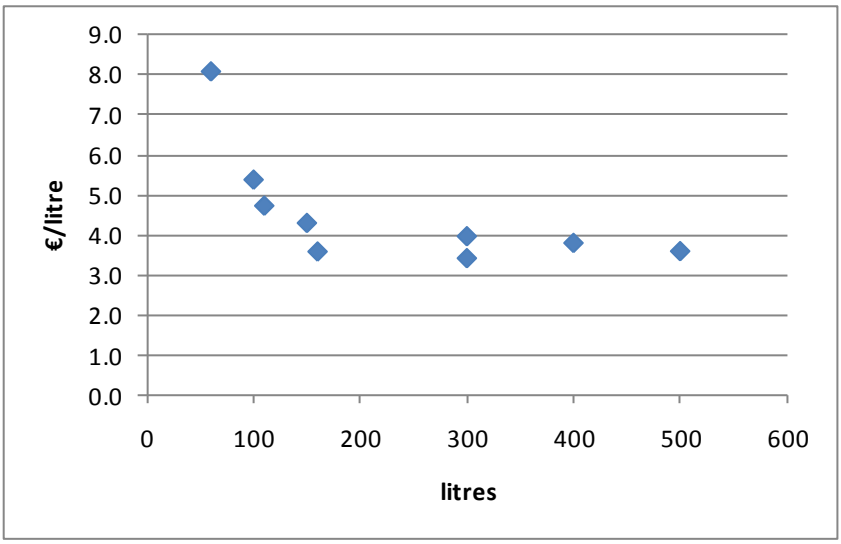


Figure 2: Prices of hot water stores in Denmark, 2011 (ref. 3).

References

1. ”Solvarme – status og strategi” (Solar heat – status and strategy). Danish Energy Agency and Energinet.dk, May 2007.
2. ”Forsyningskataloget” (Supply catalogue). Danish Energy Agency, 1988.
3. www.hedestoker.dk, September 2011.
4. ”Potentiale og muligheder for fleksibelt elforbrug med særligt fokus på individuelle varmepumper”(Opportunities for flexible electricity demand using heat pumps in private homes), Energinet.dk, January 2011.
5. Interview with mr. Mikael Byllemoes, Sydenergy, participant in Energinet.dk’s project ’From Wind Power to Heat Pumps’, September 2011.

71 UNDERGROUND STORAGE OF GAS

Brief technology description
Large volumes of gas may be stored in underground reservoirs or as liquefied gas in tanks (e.g. LNG - liquefied natural gas). This technology element is about underground storage, of which there are three principal types:

Depleted gas reservoirs are the most prominent and common form of underground storage. They are the reservoir formations of natural gas fields that have produced all their economically recoverable gas. The depleted reservoir formation is readily capable of holding injected natural gas. Using such a facility is economically attractive because it allows the re-use, with suitable modification, of the extraction and distribution infrastructure remaining from the productive life of the gas field which reduces the start-up costs. Depleted reservoirs are also attractive because their geological and physical characteristics have already been studied by geologists and petroleum engineers and are usually well known. Consequently, depleted reservoirs are generally the cheapest and easiest to develop, operate, and maintain of the three types of underground storage.

However, off-shore depleted gas fields are generally quite expensive.

Aquifer reservoirs are underground, porous and permeable rock formations that act as natural water reservoirs. In some cases they can be used for natural gas storage. Usually these facilities are operated on a single annual cycle as with depleted reservoirs. The geological and physical characteristics of aquifer formation are not known ahead of time and a significant investment has to go into investigating these and evaluating the aquifer's suitability for natural gas storage.

Salt caverns allow no gas to escape from storage. The walls of a salt cavern are strong and impervious to gas over the lifespan of the storage facility. Once a suitable salt feature is discovered and found to be suitable for the development of a gas storage facility a cavern is created within the salt feature. This is done by the process of cavern leaching. Fresh water is pumped down a borehole into the salt. Some of the salt is dissolved leaving a void and the water, now saline, is pumped back to the surface. The process continues until the cavern is the desired size. Once created, a salt cavern offers an underground natural gas storage vessel with very high deliverability. Cushion gas requirements are low, typically about 33 percent of total gas capacity.

Input
Underground storage is primarily used for natural gas (almost pure methane, CH_4), but other gasses may also be stored underground.

That may include hydrogen (H_2), but the surface facilities need be designed differently, as hydrogen is much more explosive and also aggressive towards steel structures. The costs of storing hydrogen would be larger, since the heating value per volume is about three times less (cf. Technology element 42).

If biogas (approx. 65 % CH_4 and 35 % CO_2) is to be stored underground, it would be instrumental to remove the CO_2 before storage. This is because stores are always wet, i.e. containing some water, and CO_2 in contact with water becomes acidic, posing potential problems for the surface facilities. Also, the energy density will be increased, when the CO_2 is removed.

Output
Same as input gas, but it will have to be cleaned before usage, e.g. water has to be removed.

Typical capacities
The characteristics of gas storage differ depending on the geological properties of the reservoir, which in turn define their use (ref. 2):

	Depleted field	Aquifer	Salt cavern
Working gas volume[3]	High	High	Relatively low
Cushion gas	~50 %	~80 %	~30 %
Injection rate*	Low	Low	High
Withdrawal rate*	Low	Low	High

*as compared to working gas volume

Working gas is the volume of gas that can be extracted during an operation of a facility.
Cushion gas (or base gas) is the share of residual gas that needs to be maintained to ensure appropriate reservoir pressurization.

Using highly sophisticated technology, depths of up to 3,000 m are made accessible and cavern diameters of 60 to 100 m, heights of several hundred meters, and geometrical volumes of 800,000 m^3 and more can be realized today (ref. 1).

Regulation ability
The short-term regulation characteristics of an underground gas store are not relevant for the overall gas system, as the gas transmission and distribution pipelines normally have substantial storage capacity (so-called line pack). If, for example, a power plant wishes to start up from zero to full load in a moment, the required gas volume is ready by the gate. The gas pressure in the pipeline will drop a little, much within the operational limits, and the pressure will soon rebuild by drawing gas from other parts of the system, incl. underground stores.

The primary regulation values of underground gas stores are as seasonal stores (gas production is fairly constant, while summer demand is much lower than winter demand) and as back-up supply-security in cases of emergency.

Examples of best available technology
The total gas storage capacity in Europe is around 67 billion m^3. Of 125 storage facilities analyzed by Gas Storage Europe, 64 % were depleted fields, 26 % salt caverns, 8 % aquifers and 2 % LNG peak shaving (ref. 3).

[3] A depleted field is often above 1 billion m^3, an aquifer store from around 0.3 – 0.4 to above 1 billion m^3, and salt caverns about 35 – 100 million m^3 per cavern. There are several caverns in one store.

Example, aquifer reservoir: Stenlille, Denmark. Gas is stored in porous water-saturated sandstone approx. 1.5 km below surface. Total gas volume 1.5 billion m^3, working gas 0.6 billion m^3.

Example, salt caverns: Lille Torup, Denmark. Gas is stored in 7 caverns 1-1.7 km below ground. Each cavern is 200-300 metres high and 40-60 metres in diameter. Total gas volume 0.7 billion m^3, working gas 0.44 billion m^3. The store can extract 8 million m^3/day and inject about half this flow.

References

1. Deep Underground Engineering (www.deep.de).
2. "Underground Natural Gas Storage: ensuring a secure and flexible gas supply", presentation by Jean-Marc Leroy, President of Gas Storage Europe (a sub-division of Gas Infrastructure Europe; www.gie.eu.com), January 2011.
3. Gas Storage Europe's "Investment Database", February 2010 (www.gie.eu/maps_data/GSE/database/index.asp).

Data sheet

Cavern leaching

Plant for cavern leaching	Mill. €
Total	9.9

Establishment of one cavern, 100 million Nm3 (approx. 1.1 TWh)

	Mill. €
Construction and equipment	22
Cushion gas for one cavern (40% of total)	14
Total cost, 100 mio Nm3 active volume	36

Process equipment; injection 200,000 Nm3/hour (approx. 2200 MW), withdrawal 600,000 nM3/hour (approx. 6600 MW)

	Mill. €
Construction work	2.8
Compressors, incl. auxiliaries	30
Udtrækstog	13
Withdrawal equipment	4.5
Connections, transformer, regulation, and instruments	13
Total investment cost	63

A new greenfield store, equivalent to Lille Torup in Denmark, would require one leaching plant, 5 caverns, and one process plant.
Total investment cost 254 mill. €

Operation and maintenace, salt cavern, 400-500 million m3 working gas

	Mill. € per year
Electricity	0.7 - 1.1
Gas consumption to reheat extracted gas	0.13
Total, incl. administration	6.5

72 HYDROGEN STORAGE

Brief technology description
Hydrogen serves as a storage and transportation medium for energy. In general there are five different ways of storing hydrogen (ref. 1):

- storage of pressurised gas
  - in caverns
  - in tanks e.g. for mobile applications up to 700 bar
  - in pipelines between producers and consumers (like natural gas)
- storage of liquid hydrogen
  - liquefied at -253°C, stored in cryo-tanks
- storage via absorption
  - Metal hydride storage used in submarines commercially today, heavy
- storage in chemical compounds, including SNG, ammonia and synthetic liquid hydrocarbons (DME, Methanol)
- storage via adsorption
  - Adsorption at low temperatures on high surface area carbon and similar compounds, under development.

Input
Hydrogen

Output
Hydrogen
The lower heating value of hydrogen is 10.79 MJ/Nm^3 (0 ^{o}C and 1.015 bar) or 3.00 kWh/Nm^3, while the higher heating value is 12.75 MJ/Nm^3. The density is 0.0899 kg/Nm^3.

Typical plant capacities
Hydrogen storages can differ greatly in sizes from caverns of 100-100.000 GJ down to pressurised tanks of 300 bar with capacities of 0.4-2.5 GJ (ref. 1)[4].

Regulation ability
Production and storage of hydrogen is a tool to enhance regulation ability of the overall energy system, without having to convert the electricity into low value energy like heat. How fast the hydrogen can be converted into electricity and heat depends on the type and number of hydrogen converting fuel cells.

[4] General Motors and QUANTUM Fuel System Systems Technology Worldwide has furthermore developed and tested a 700 bar hydrogen storage system which extends the range of a fuel cell vehicle by 60-70 percent compared to an equivalent-sized 350 bar system. (4)

Environmental aspects
Hydrogen is, like electricity, an energy carrier, which is only as clean as the energy source from which it is produced.

Some emissions of hydrogen will take place during storage, distribution and utilisation of the hydrogen. Hydrogen emits to the stratosphere, where it connects with oxygen to form water. An increased amount of water in the stratosphere will lead to further destruction of the ozone layer. It is however calculated that the increase in water in the stratosphere due to hydrogen will be significantly less than the increases, which are expected already to have appeared in the stratosphere during the last 50 years. Therefore, it is uncertain whether future emissions of hydrogen may lead to further damages on the ozone layer (ref. 2 + 3).

Research and development
Most research in hydrogen storage is directed towards storage in tanks for mobile applications, where the challenge is to store hydrogen in tanks under high pressure or liquefied with low weight while ensuring safety and energy amounts for ranges comparable to cars run on fossil fuels today.

Examples of best available technology
When it is necessary to store large amounts of hydrogen in a future energy economy then hydrogen can be pumped into subterranean cavern storages. The method is already in use in UK (Tees Valley), France and the USA (ConocoPhillips Clemens Terminal built a 2500 tonnes cavern store in Texas in the 1980'es, while Praxair established a hydrogen cavern store, also in Texas, more recently). Caverns used for storage of natural gas could be used for the storage of hydrogen in the future.

References
1) http://www.hynet.info/hydrogen_e/index00.html
2) http://www.dmi.dk/dmi/brint_fra_brandselsceller_kan_maske_skade_ozonlaget
3) http://www.sciencemag.org/cgi/content/full/300/5626/1740

Data sheet

Technology	Hydrogen storage, cavern					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Output capacity, MW	2					1
Storage volume, MWh	10					1
Overall cycle efficiency, AC-AC (%)	35				A	1
Technical lifetime (year)	30					1
Financial data						
Investment storage, € per kWh storage volume	11				A+B+C	1
Investment converter, € per kW output capacity	3000				A+B+C	1
Fixed O&M (€/MW/year)						
Variable O&M (€/MWh)						

References:

1 "Economical and technical evaluation of energy storage systems", presentation by J. Oberschmidt & M. Klobasa, Fraunhofer Institut, at the "Third International Renewable Energy Storage Conference (IRES 2008)", Berlin, November 2008

Notes:

A System: PEM electrolysis, storage of hydrogen at 30 bar, and a gas engine to convert back to AC.

B The two investment components shall be added, cf. paragraph 1.3 in the introductive chapter.

C Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

80 ELECTROLYSIS

Brief technology description
Electrolysis is a process, where electricity is used to electrochemically reduce or oxidise a reactant into fuel. The water decomposition via electrolysis takes place in two partial reactions at both electrodes, which are separated by an ion-conducting electrolyte. At the negative electrode (cathode) hydrogen is produced and on the positive electrode (anode) oxygen is produced. To keep the product gases separated the two reaction compartments are separated. Depending on the type of electrolyser, separation is either achieved by means of at solid electrolyte (SOEC, PEMEC) or a micro-porous diaphragm (alkaline).

Several types of electrolysis exist (ref. 1+2):

- Alkaline Electrolysis (AEC).
  This process works with alkaline, aqueous electrolytes and has been used for hydrogen generation since the end of the 18th century. Currently most commercially available electrolysers are based on alkaline electrolysers. The anode compartment and cathode compartment are separated by a micro-porous diaphragm to avoid blending of the product gases. Operation temperature of 80 °C and op to 30 bar in pressure is industrial standard.
- High-Temperature Electrolysis (Solid oxide electrolysis).
  High-temperature electrolysis using a solid oxide electrolyser cell (SOEC) has been discussed and tested as an interesting alternative. It is an advantage to apply part of the energy needed for dissociation as high-temperature heat at around 800-1000°C into the process and then to be able to run the electrolysis with reduced consumption of electric power. Furthermore, SOEC has the possibility of electrolysing mixtures of steam and CO_2 into a mixture of hydrogen and CO, so-called syngas, from which artificial hydrocarbons may be produced.
- Low Temperature Electrolysis (Polymer electrolyte electrolysis).
  PEM electrolysis is based on a solid polymer electrolyte membrane electrolyser cell (PEMEC), which operates at around 80°C like most conventional PEM fuel cells. The PEMEC is compact and the low operating temperature enables fast start-up. The produced hydrogen is clean (no traces of electrolyte) and can be delivered at pressures up to 16 bar (higher pressure systems are under development). The PEMEC is well suited for decentralized hydrogen production with local hydrogen storage facilities.

The conventional process is the alkaline electrolysis, which has been in commercial use for more than 100 years.

Input
Electricity and water

Output
Hydrogen and oxygen.

The lower heating value of hydrogen is 10.79 MJ/Nm^3 (0 ^{o}C and 1.015 bar) or 3.00 kWh/Nm^3, while the higher heating value is 12.75 MJ/Nm^3 or 3.54 kWh/Nm^3. The density is 0.0899 kg/Nm^3.

Typical plant capacities
Alkaline 4 kW-100 MW, PEM electrolysis 1-20 kW.

Regulation ability
Good dynamic performance is a feature of both alkaline electrolysis and PEM electrolysis, which allows for fluctuating operation. Therefore they are suited for applications with fluctuating power plants (primarily renewables like wind solar etc.). For high temperature electrolysis longer start up times must be expected.

Advantages/disadvantages
- Electrolysis can be performed in centralised or decentralised plants.
- Decentralised production of hydrogen makes sense, when the hydrogen needs to be used locally.
- Electrolysis is not necessarily more efficient in large scale than in small scale.
- With centralised production and utilisation, losses during distribution are avoided.

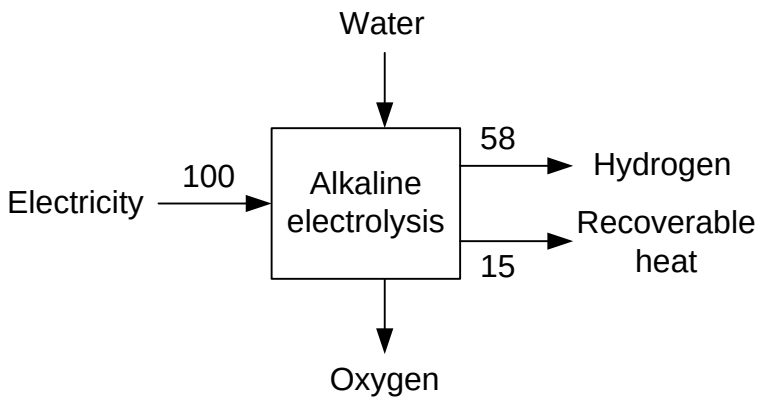
Environmental aspects
Hydrogen is, like electricity, an energy carrier, which is only as clean as the energy source from which it is produced. Electrolysis can be used to enhance the value and thereby possibly the capacity of surplus energy produced from fluctuating renewable energy sources such as wind.

Research and development
Efforts in hydrogen production are focused on small reformers (fuel to hydrogen), alkaline electrolysis, SOEC electrolysis, PEM electrolysis, electrolysis by reversible fuels, and production of hydrogen-rich liquid fuels.

In Denmark research is being made in the field of solid oxide electrolysis, PEM electrolysis and alkaline electrolysis.

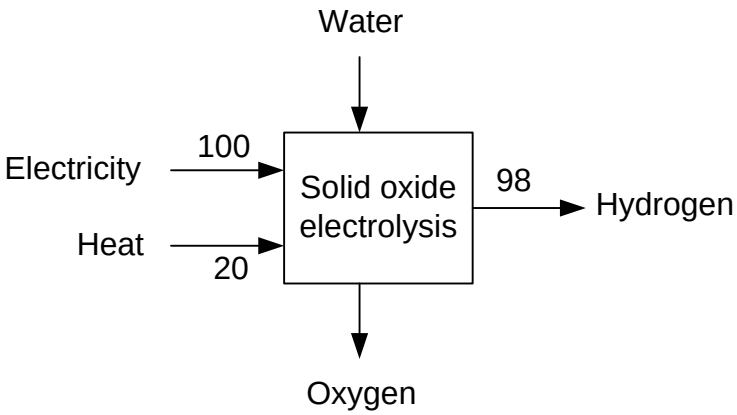
Special remarks
The energy balances are quite different for different technologies, as illustrated in the below two figures, each with 100 energy units of electricity as input and based on the low heating value of hydrogen.

The alkaline electrolysis generates surplus heat:



Based on the high heating value, the hydrogen production would be 68.

The solid oxide electrolysis consumes heat:



The temperature of the heat source should be the same as the working temperature, i.e. 800 – 1000 ^{o}C. Based on the high heating value, the hydrogen production would be 114.

The energy balance of the PEMEC is similar to that of the alkaline electrolysis, only difference being about 70% hydrogen and 18% heat generated (ref. 2).

References

1) Topsoe Fuel Cell, October 2009.
2) IRD, November 2009.

Data sheets

Technology	Electrolyser AEC					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	< 3.4					1
Efficiency, electricity to hydrogen (%)	43-66	50-68	53-70		A	3
Electricity consumption (kWh/Nm3)	4.5-7.0	4.4-6.0	4.3-5.7			3
Useful heat out (kWh/Nm3)	0.78				B	1
Operating temperature (degr. C)	60-80	60-80	60-90			3
Technical lifetime (years)	20-30	25-30	30			3
Construction time (years)						
Environment						
Financial data						
Specific investment (M€/MW)	1.4	1.0			C	2
Total O&M (% of investment per year)	4	4	4			4

References:

1 "Elektrolyse i Danmark" (Electrolysis in Denmark; in Danish). The Danish Partnership for Hydrogen and Fuel Cells (www.hydrogennet.dk); August 2009

2 Danish Gas Technology Centre (DGC), January 2012.

3 Frauenhofer: Workshop præsentation: ”NOW-Studie Stand und entwiklungspotenzial der wasserelektrolyse zur herstellung von Wasserstoff aus regenerativen Energien” Präsentation der arbeitsergebnisse (Teil II) Tom Smolinka, Jürgen Garche. Frauenhofer-Institut für solare Energisysteme ISE und FCBAT (Garche). NOW- Workshop, Kempinski, Berlin, May 2011.

4 "Electrolysis for Energy Storage & Grid Balance in West Denmark", Incoteco, 2004.

Notes:

A The stated efficiencies are for single cells. For complete multi-cell systems there may be a loss of 2-20%. The efficiency is measured using the Low Heating Value of hydrogen. Multiply by 1.184 to convert to High Heating Value.

B AEC generates surplus heat.

C The stated price is for a 485 m3/hour plant. Main equipment 2015 is 0.9 M€/MW.

Technology	Electrolyser SOEC					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)		5	5			1
Efficiency, electricity to hydrogen (%)		98	98		A	1
Electricity consumption (kWh/Nm3)		3.1	3.1			1
Heat demand (kWh/Nm3)		-0.55	-0.55		B	1
Total energy efficiency (%) net		83	83		B	1
Operating temperature (degr. C)		850-1000	850-1000			2
Technical lifetime (years)		20	20			3
Construction time (years)						
Environment						
Financial data						
Specific investment (M€/MW)		0.59	0.59		C+E	4
Total O&M (€/MW/year)		15000	15000		D+E	4

References:

1 "Elektrolyse i Danmark" (Electrolysis in Denmark; in Danish). The Danish Partnership for Hydrogen and Fuel Cells (www.hydrogennet.dk); August 2009

2 Risø, 2003

3 ”Scenarier for samlet udnyttelse af brint som energibærer i Danmarks fremtidige energisystem”. RUC, april 2001

4 Topsoe Fuel Cell, October 2009

Notes:

A The stated efficiencies are for single cells. For complete multi-cell systems there may be a loss of 2-20%. The efficiency is measured using the Low Heating Value of hydrogen. Multiply by 1.184 to convert to High Heating Value.

B SOEC consumes heat. Total energy efficiency equals (hydrogen plus heat out) divided by (electricity plus heat in).

C Ref. 4 quotes a price of 750 USD/kW in 2025. This price is here used for both 2020 and 2030.

D O&M is 2.5% of initial investment per year.

E Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

Technology	Electrolyser PEMEC					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	0.045				A	1
Efficiency, electricity to hydrogen (%)	68 - 72				B	1
Electricity consumption (kWh/Nm3)	4.0					2
Useful heat out (+) or in (-) (kWh/Nm3)	0.72					2
Total energy efficiency (%) net	88					2
Operating temperature (degr. C)	60 - 80	100 - 200				1
Technical lifetime (hours)	4000	30000				2
Construction time (years)						
Environment						
Financial data						
Specific investment (M€/MW)	6	1				2
Total O&M (€/MW/year)						

References:

1 "Elektrolyse i Danmark" (Electrolysis in Denmark; in Danish). The Danish Partnership for Hydrogen and Fuel Cells (www.hydrogennet.dk); August 2009

2 IRD, November 2009.

Notes:

A Largest demonstrated stack size.

B The stated efficiency is for single cells. For comlete multi-cell systems there may be a loss of 2-20%. The efficiency is measured using the Low Heating Value of hydrogen. Multiply by 1.184 to convert to High Heating Value.

C Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

81 CENTRALISED BIOGAS PLANTS

Brief technology description
Animal manure from a number of farms and organic waste from food processing and other industries are transported to a plant. The biomass is either transported by road or pumped in pipes. At the plant, the biomass is treated in an anaerobic process, which generates biogas. The biogas is converted into heat and power in a CHP plant. The CHP plant can either be located at the biogas plant, or it can be an external plant to where the gas is piped.

The biomass is received and stored in pre-storage tanks. Danish plants use continuous digestion in fully agitated digesters. This implies removing a quantity of digested biomass from the digesters and replacing it with a corresponding quantity of fresh biomass, typically several times a day. The digesters are heated to either 35 - 40 ^{o}C (mesophilic digestion) or 50 - 55 ^{o}C (thermophilic digestion).

This technology sheet does not include single-farm biogas digesters, biogas from wastewater treatment plants and landfill sites.

Input
Bio-degradable organic waste without environmentally harmful components. Typically, animal manure (80 - 90 %) and organic waste from industry (10 - 20 %). Sludge from sewage treatment plants and the organic fraction of household waste may also be used.

Rules for using animal products have been tightened by EU Directive 1774/2002 of 3 October 2002, amended by Directive 808/2003 of 12 May 2003.

Output
Biogas containing 60-70% methane (CH_4), 30-40% carbon dioxide (CO_2) and < 500 ppm H_2S (after gas cleaning).

Methane has a lower heating value 35.9 MJ/Nm^3. Biogas with 65% methane thus has a heating value of 23.3 MJ/Nm^3.

For biogas plants based on energy crops, the methane content may be as low as 50% (ref. 3).

The data presented in this technology sheet assume that the biogas is used as fuel in an engine, which produces electricity and heat, or sold to a third party. However, the gas may also be injected into the natural gas grid or used as fuel for vehicles, cf. Technology sheet no. 82 on biogas upgrading.

The digested biomass is used as fertiliser in crop production.

The output of biogas depends much on the amount and quality of supplied organic waste. For manure the gas output typically is 14 – 14.5 m^3 methane per tonne, while the gas output typically is 30 – 130 m^3 methane per tonne for industrial waste.

Typical capacities
There are about 20 centralised biogas plants in operation in Denmark. The average daily input is 50 – 600 tonnes raw material, typically delivered by 10 – 100 farms. The average daily yield is 1,000 – 25,000 Nm^3 biogas, which can be converted to 0.1 – 3 MW electricity. Due to economy-of-scale, the trend is towards larger plants.

Regulation ability
A typical biogas plant can regulate the production approximately +/- 15% within a day by adjusting the feed pumps (ref. 2). Also, a typical plant has a gas store of approximately a half day's production. Thus, gas supply can normally match demand variations within the day.

Biogas production may be increased during winter, when the energy demand is high, by adding organic materials with high methane potential, e.g. silage from energy crops, glycerol (residue from production of biodiesel), solid manure or garden waste. However, there is a biological limit to how fast the production can be regulated. A biogas plant digesting only animal slurry during summer, may thus increase the gas yield from 14-14.5 m^3 methane per tonne to about 45-50 m^3 methane per tonne during a period of 3 to 4 weeks (ref. 2).

The additional income from gas sales may not balance the extra costs of storing feedstock and digested biomass. Also, the emission of greenhouse gasses may increase (ref. 4).

Environment
The biogas is a CO_2-neutral fuel. Also, without biogas fermentation significant amounts of the greenhouse gas methane will be emitted to the atmosphere. For biogas plants in Denmark the CO_2 mitigation cost has been determined to approx. 5 € per tonne CO_2-equivalent (ref. 1).

The anaerobic treated organic waste product is almost odour free compared to raw organic waste.

Advantages/disadvantages
- The CO_2 abatement cost is quite low, since methane emission is mitigated.
- Saved expenses in manure handling and storage; provided separation is included and externalities are monetised.
- Environmentally critical nutrients, primarily nitrogen and phosphorus, can be redistributed from overloaded farmlands to other areas.
- The fertilizer value of the digested biomass is better than the raw materials. The fertilizer value is also better known, and it is therefore easier to distribute the right amounts on the farmlands.
- Compared with other forms of waste handling, biogas digestion of solid biomass has the advantage of recycling nutrients to the farmland – in an economically and environmentally sound way.

Research and development

Lack of sufficient organic industrial wastes can become a barrier as more centralised biogas plants are established. Therefore, the main objective of the Danish biogas R&D activities (ref. 5) is to improve the plants to become economically attractive either digesting only manure or by adding less attractive organic wastes with more secure supplies in the long term.

References

1. Danish Climate Strategy, Ministry of Environment, February 2003.
2. Danish Energy Agency, 2009.
3. Danish Gas Technology Centre, 2009.
4. "Øget produktion og anvendelse af biogas i Danmark" (Increased production and use of biogas in Denmark; in Danish), Danish Gas Technology Centre, 2009.
5. "Forsknings- og udviklingsstrategi for biogas" (Research and development strategy for biogas; in Danish), Danish Energy Agency, Energy Technology Development Programme (EUDP) and Energinet.dk, August 2009.

Data sheets

Data are given for four plant sizes: 300, 550, 800, and 1000 tonnes input per day.
The first three plants digest a mixture of animal slurry and industrial organic waste, while the latter digests only animal waste and maize silage.
Another difference is that the first three plants have their own combined-heat-and-power plants, while the latter supplies the gas to a third party.

Technology	Centralised Biogas Plant with CHP					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Daily input of manure & organic waste in tonnes	**300**					1
Biogas output Nm3/m3 raw material	30 - 40	28 - 35	28 - 35		C	7
Electricity efficiency (%) net	40 - 45	43 - 48	45 - 50		E	
Electricity generating capacity (MW)	1.5	1.4	1.5		F	
Heat generation capacity (MJ/s)	1.7	1.4	1.4		E	
Availability (%)	98					4
Technical lifetime (years)	20					2
Construction time (years)	1					2
Own electricity consumption, kWh per ton biomass	6					1
Own heat consumption, kWh per m3 of raw material	34					5
Environment, biogas plant including co-generation						
SO2 (g per GJ fuel)	19.2	19.2	19.2	19.2		8;3;3;3
SO_2 (degree of desulphurisation, %)	0	0	0	0		3
NO_X (g per GJ fuel)	540	540	540	540		8;3;3;3
CH4 (g per GJ fuel)	323	323	323	323		8;3;3;3
N2O (g per GJ fuel)	0.5	0.5	0.5	0.5		8;3;3;3
Financial data						
Total plant investment, excl. transport equipment and co-generation plant (M€)	5.5	5.2	5.2		A+B;D	7
Total investment, co-generation plant (M€)	0.25	0.25	0.25		D	1
Specific investment, incl. co-generation plant (M€/MW)	5.8	5.4	5.4		D	
Total O&M (€/tonnes supplied raw material), excl. transport	3.1	3.1	3.1		D	7
Total O&M (€/MWh)	35	35	35		D	

References:

1 Samfundsøkonomiske analyser af biogasfællesanlæg 2002. Fødevareøkonomisk Institut. Rapport 136
2 "Teknologidata for vedvarende energianlæg, Del 2, Biomasseteknologier. Danish Energy Agency, 1996.
3 Danish Energy Agency, 2009.
4 Lemvig Biogas Plant
5 Ramboll estimates based on monthly biogas data from Danish Energy Agency
6 Varme Ståbi
7 Danish Energy Agency, 2003.
8 National Environmental Research Institute, Denmark, 2009 (data from 2007).

Notes:

A Transport is typically 1.6-2.4 €/tonne; average distance between farms and plant 4-8 km.
B The deceasing investment costs presume an escalated market
C The output figures are estimated avarages for Danish conditions, recognizing the limited availability of industrial wastes
D Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying with a general inflation factor 1.2306
E Assumed same efficiencies as Technology element '06 Gas engines'
F Assumed that 10% of the gas is used for process heating, and that the engine operates 6500 hours/year.

Technology	Centralised Biogas Plant with CHP					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Daily input of manure & organic waste in tonnes	**550**					1
Biogas output Nm3/m3 raw material	28 - 35	25 - 30	25 - 30		C	7
Electricity efficiency (%) net	40 - 45	43 - 48	45 - 50		E	
Electricity generating capacity (MW)	2.4	2.3	2.3		F	
Heat generation capacity (MJ/s)	2.8	2.3	2.2		E	
Availability (%)	98					4
Technical lifetime (years)	20					2
Construction time (years)	1					2
Own electricity consumption, kWh per ton biomass	5					1
Own heat consumption, kWh per m3 of raw material	34					5
Environment, biogas plant including co-generation						
SO2 (g per GJ fuel)	19.2	19.2	19.2	19.2		8;3;3;3
SO_2 (degree of desulphurisation, %)	0	0	0	0		3
NO_X (g per GJ fuel)	540	540	540	540		8;3;3;3
CH4 (g per GJ fuel)	323	323	323	323		8;3;3;3
N2O (g per GJ fuel)	0.5	0.5	0.5	0.5		8;3;3;3
Financial data						
Total plant investment, excl. transport equipment and co-generation plant (M€)	7.8	7.4	7.4		A+B;D	7
Total investment, co-generation plant (M€)	0.41	0.41	0.41		D	1
Specific investment, incl. co-generation plant (M€/MW)	4.1	3.8	3.8		D	
Total O&M (€/tonnes supplied raw material), excl. transport	2.5	2.5	2.5		D	7
Total O&M (€/MWh)	31	31	31		D	

References:

1 Samfundsøkonomiske analyser af biogasfællesanlæg 2002. Fødevareøkonomisk Institut. Rapport 136
2 "Teknologidata for vedvarende energianlæg, Del 2, Biomasseteknologier. Danish Energy Agency, 1996.
3 Danish Energy Agency, 2009.
4 Lemvig Biogas Plant
5 Ramboll estimates based on monthly biogas data from Danish Energy Agency
6 Varme Ståbi
7 Danish Energy Agency, 2003.
8 National Environmental Research Institute, Denmark, 2009 (data from 2007).

Notes:

A Transport is typically 1.6-2.4 €/tonne; average distance between farms and plant 4-8 km.
B The deceasing investment costs presume an escalated market
C The output figures are estimated avarages for Danish conditions, recognizing the limited availability of industrial wastes
D Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying with a general inflation factor 1.2306
E Assumed same efficiencies as Technology element '06 Gas engines'
F Assumed that 10% of the gas is used for process heating, and that the engine operates 6500 hours/year.

Technology	Centralised Biogas Plant with CHP					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Daily input of manure & organic waste in tonnes	**800**					1
Biogas output Nm3/m3 raw material	25 - 30	24 - 28	24 - 28		C	2
Electricity efficiency (%) net	40 - 45	43 - 48	45 - 50		E	
Electricity generating capacity (MW)	3.0	3.1	3.2		F	
Heat generation capacity (MJ/s)	3.6	3.2	3.0		E	
Availability (%)	98					4
Technical lifetime (years)	20					2
Construction time (years)	1					2
Own electricity consumption, kWh per ton biomass	4					1
Own heat consumption, kWh per m3 of raw material	34					5
Environment, biogas plant including co-generation						
SO2 (g per GJ fuel)	19.2	19.2	19.2	19.2		8;3;3;3
SO_2 (degree of desulphurisation, %)	0	0	0	0		3
NO_X (g per GJ fuel)	540	540	540	540		8;3;3;3
CH4 (g per GJ fuel)	323	323	323	323		8;3;3;3
N2O (g per GJ fuel)	0.5	0.5	0.5	0.5		8;3;3;3
Financial data						
Total plant investment, excl. transport equipment and co-generation plant (M€)	9.5	9.0	9.0		A+B;D	7
Total investment, co-generation plant (M€)	0.49	0.49	0.49		D	1
Specific investment, incl. co-generation plant (M€/MW)	3.4	3.2	3.2		D	
Total O&M (€/tonnes supplied raw material), excl. transport	2.2	2.2	2.2		D	7
Total O&M (€/MWh)	31	31	31		D	

References:

1 Samfundsøkonomiske analyser af biogasfællesanlæg 2002. Fødevareøkonomisk Institut. Rapport 136
2 "Teknologidata for vedvarende energianlæg, Del 2, Biomasseteknologier. Danish Energy Agency, 1996.
3 Danish Energy Agency, 2009.
4 Lemvig Biogas Plant
5 Ramboll estimates based on monthly biogas data from Danish Energy Agency
6 Varme Ståbi
7 Danish Energy Agency, 2003.
8 National Environmental Research Institute, Denmark, 2009 (data from 2007).

Notes:

A Transport is typically 1.6-2.4 €/tonne; average distance between farms and plant 4-8 km.
B The deceasing investment costs presume an escalated market
C The output figures are estimated avarages for Danish conditions, recognizing the limited availability of industrial wastes
D Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying with a general inflation factor 1.2306
E Assumed same efficiencies as Technology element '06 Gas engines'
F Assumed that 10% of the gas is used for process heating, and that the engine operates 6500 hours/year.

Technology	Centralised Biogas Plant without CHP					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Daily input of manure & organic waste in tonnes	**1000**					
Capacity factor (full load operation), hours/year	8760					1
Methane output, Nm3 per tonne raw material	19.7				A	1
Gas production, MWh/year	71500					1
Gas flaring, MWh/year	700					1
Gas delivery, MWh/year	70800					1
Process heat demand, MWh/year	6800				B	1
Own electricity consumption, MWh/year	2000					1
Technical lifetime (years)	20					1
Construction time (years)	1					1
Environment						
SO_2 (degree of desulphurisation, %)						
NO_X (g per GJ fuel)						
CH4 (g per GJ fuel)						
N2O (g per GJ fuel)						
Financial data						
Biogas plant, M€	15				C	1
Vehicles for biomass transport, M€	2.0				C	1
Gas pipeline (16 km), M€	1.9				C	1
Total investment, M€	18				C	1
Total investment, € per tonne raw material	50				C	1
Operation (€/tonne supplied raw material), excl. transport	4.9				C	1
Maintenance (€/tonne supplied raw material), excl.	0.78				C	1
O&M, biomass transport (€/tonne)	2.7				C	1

References:

1 Danish Energy Agency, 2009

2 Eltra PSO project 3141: "Kortlægning af emissionsfaktorer fra decentral kraftvarme", 2003

Notes:

A 92% animal slurry + 8% solid biomass (animal dung, slurry fibre, maize silage). Average dry matter content

B Process heat supplied from external source.

C Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

82 UPGRADED BIOGAS

Brief technology description
Biogas can be upgraded for injection in natural gas grids or for use as vehicle fuel.

The gas is usually cleaned before upgrading. Cleaning removes water moisture, particles, hydrogen sulphide, and ammonia. Upgrading removes CO_2. It is rather expensive to remove nitrogen, so this is seldom done.

The two dominating upgrading technologies are the water scrubber technology and the Pressure Swing Adsorption (PSA) technology.

In the water scrubber the biogas is contacted with water (either by spray or bubbling through) to wash out CO_2 but also hydrogen sulphide, since these gases are more soluble in water than methane. The absorption process is purely physical.

The PSA (also called the molecular sieve) separates some gas components from a mixture of gases under high pressure according to the components' molecular characteristics and affinity for an adsorbent material (e.g. active carbon). The process then swings to low pressure to desorb the adsorbent material.

Other technologies are:

A. Chemical absorption in amines, like mono ethanol amine (MEA). This process has promises of producing the best quality product gas, having the lowest methane loss and the smallest electricity consumption, although a higher demand for process heat (ref. 4).
B. Scrubbing by polyethylene glycol (registered trademarks Selexol and Genosorb). This is similar to water scrubbing, the major difference being that CO_2 and H_2S are more soluble in glycol than in water. Glycol scrubbing is always designed with recirculation.
C. Cryolithic separation; being developed. The process will produce liquid CO_2, which is easier to use or handle than gaseous CO_2.
D. Membrane separation

Input
Biogas from an anaerobic digester typically contains 50-70% methane (CH_4) and 30-50% CO_2. In addition there are some contaminants: Hydrogen sulphide (H_2S), ammonia (NH_3) and various trace components.

The main contaminants, that can have an impact on distribution grids, are moisture, H_2S, CO_2, and O_2. O_2 is not found in raw digester biogas, but some O_2 may be introduced during sulphur removal. Otherwise, O_2 is a substantial component of landfill gas.

Output
A gas with a high and constant heating value and few contaminants.

The Wobbe index (W), which characterises the energy content of a gas passing through a nozzle at a certain pressure, is defined by the equation

$$W = \frac{H}{\sqrt{d}}$$

where H is the heating value (MJ/Nm^3) and d is the relative density of the gas (density of gas divided by density of air). W equals 53.5 MJ/Nm^3 for pure methane and 27.3 MJ/Nm^3 for biogas (65% CH_4 plus 35% CO_2). The Wobbe index requirement for the Danish gas distribution systems is 50.8 – 55.9 MJ/Nm^3.

Current upgrading technologies produce gas qualities, which are acceptable from a technical point-of-view, but are a challenge from an accounting point-of-view in a Danish gas system supplied with North Sea natural gas, which has a relatively high heating value. It is possible to add propane to obtain the same heating value as natural gas and thereby solve the commercial challenge. This costs about 0.03 € per m^3 upgraded gas (ref. 3). When the gas is to be injected into a natural gas system, a pressure of 4 bars is usually sufficient.

There is no technical European standard for biogas injection into natural gas grids, although Marcogaz (www.marcogaz.org), the technical association of the European natural gas industry, has developed a draft recommendation. Also, a working group under CEN is developing (2009) a standard for injection of non-conventional gases into natural gas grids, and in December 2011 the European Commission established a working group to define a common standard.

Some EU countries (France, Germany, Holland, Sweden, and Switzerland) have adopted their own regulations. These standards are mostly based on natural gas standards, with amendments concerning biogas properties (ref. 2).

If used as vehicle fuel, the upgraded gas needs be pressurized to about 200 bars. The gas can be used in the same vehicles that use natural gas. Worldwide, there are more than 5 million gas vehicles, and more than 50 manufacturers offer a range of 250 models of commuter, light and heavy duty vehicles (ref. 5). The gas may also be condensed to liquid gas (below 162 ^oC), which contains three times more energy per volume than compressed gas.

Environment

Some technologies have substantial methane losses. Suppliers of water scrubbers and PSA's typically claim a maximum of 2 % methane loss, but in some cases higher losses have been measured (ref. 1). However, additional equipment is delivered as part of the standard package to remove most of this methane. Using catalytic oxidation, the emission is reduced to below 0.2 % (ref. 3).

When upgraded biogas is used as vehicle fuel, emissions of particles, soot, NOx and non-methane hydrocarbons are drastically reduced, compared with gasoline and diesel (ref. 5).

Research and development
Currently, there is much focus on the further development of chemical absorption in amines and polyethylene glycol for carbon capture and storage (CCS) from large-scale power plants. This may have positive consequences for smaller systems as well.

Additional remarks
The economy of scale is insignificant for capacities above 1000 m^3/hour:

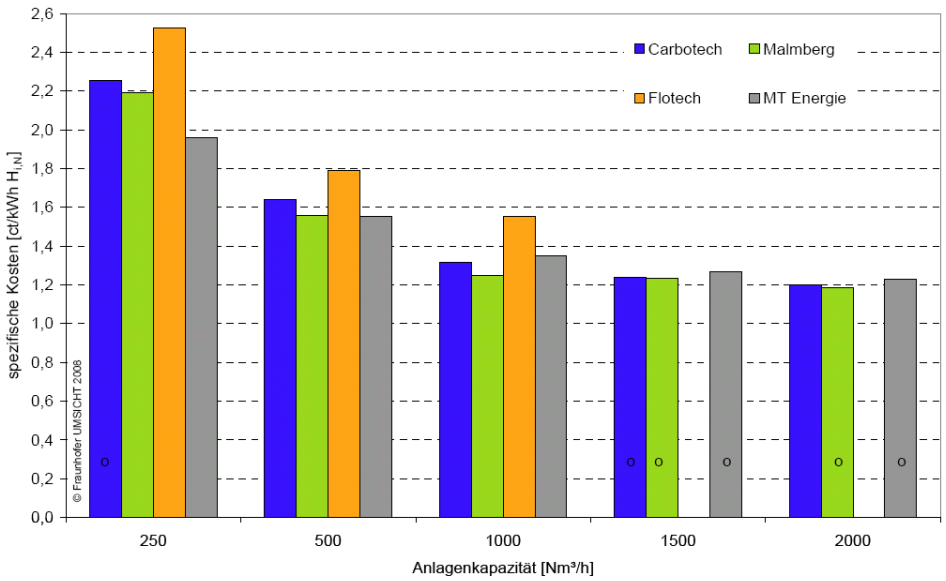


Figure 1: Capital costs in Eurocents per kWh product gas for various upgrading technologies as a function of plant scale in Nm^3/hour. The figure is based on experiences from Germany, where much biogas is produced from energy crops. The assumed methane content is 53% (ref. 4).

Investment costs depend on the inlet volume flow rather than the output flow. Costs for upgrading biogas with higher methane contents than 53% is therefore lower per m^3 outlet gas than shown in Figure 1.

References

1. ”Utvärdering av uppgraderingstekniker för biogas” (assessment of biogas upgrading technologies; in Swedish), Margareta Persson, Svenskt Gastekniskt Center (SGC), November 2003.
2. ”Regulation draft of biogas commercialisation in gas grid”, a project funded by the European Commission (the Altener programme). Final report June 2005. Reports available at http://www.icaen.net/uploads/bloc1/ambits_actuacio/Biocomm/INDEX.HTML#12
3. Danish Gas Technology Centre, interview 2009.
4. “Technologien und Kosten der Biogasaufbereitung und Einspeisung in das Erdgasnetz. Ergebnisse der Markterhebung 2007-2008”. Urban, Wolfgang et al, Fraunhofer Institut Umwelt-, Sicherheits-, Energietechnik, 2008.

5. ”Biogas upgrading to vehicle fuel standards and grid injection”, International Energy Agency, December 2006.
6. “Biogas upgrading and utilization”, International Energy Agency, undated.

Data sheets

Data are shown for two different capacities, 200 and 1000 Nm^3 upgraded gas per hour:

Technology	Upgraded biogas Water scrubber and pressure swing adsorption					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity (Nm3/hour)	200					
Methane content of raw gas	65					
Electricity consumption (% of upgraded gas)						
Compression for vehicle use (200 bar)	3 - 6				A	1
Injection into natural gas grid (4-7 bar)	0				B	2
Availability (%)	95					1
Technical lifetime (years)	15					2
Construction time (years)	0.5	0.5	0.5	0.5	C	2
Environment						
Methane emission, %	0.1-0.2				D	2
Financial data						
Specific investment costs (€ per Nm3/h raw gas)	3500	3300	2900	2800	D;E+H	1;2;2;2
O&M (€ per Nm3 raw gas)	0.03-0.05	0.03-0.05	0.03-0.05	0.03-0.05	F;G+H	2

References:

1 ”Utvärdering av uppgraderingstekniker för biogas” (assessment of biogas upgrading technologies; in Swedish), Margareta Persson, Svenskt Gastekniskt Center (SGC), November 2003.

2 Danish Gas Technology Centre, 2009.

Notes:

A Some of the used electricity can be regained as process heat.

B Compression to about 4-8 bar is part of the upgrading process itself, and electricity consumption is thus part of O&M

C Upgrading plants are often delivered off-the-shelf as plug-in containers.

D Some processes release significant amounts of methane, but additional equipment (part of a standard delivery) will then oxidize most of the methane.

E Only a modest cost decrease is expected (20% by 2050), since current technologies are established technologies. However, since assembling requires much manual labour, production outside OECD countries may decrease the cost.

F O&M cost may decrease with increased market volumes and may increase with increasing electricity prices. Therefore, no development in O&M cost is expected.

G Assuming 7500 equivalent full-load operational hours per year.

H Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

Technology	Upgraded biogas Water scrubber and pressure swing adsorption					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity (Nm3/hour)	1000					
Methane content of raw gas	65					
Electricity consumption (% of upgraded gas)						
Compression for vehicle use (200 bar)	3 - 6				A	1
Injection into natural gas grid (4-7 bar)	0				B	2
Availability (%)	95					1
Technical lifetime (years)	15					2
Construction time (years)	0.5	0.5	0.5	0.5	C	2
Environment						
Methane emission, %	0.1-0.2				D;E	2
Financial data						
Specific investment costs (€ per Nm3/h raw gas)	2000	1900	1700	1600	D;E+H	1;2;2;2
O&M (€ per Nm3 raw gas)	0.03-0.05	0.03-0.05	0.03-0.05	0.03-0.05	F;G+H	2

References:

1 ”Utvärdering av uppgraderingstekniker för biogas” (assessment of biogas upgrading technologies; in Swedish), Margareta Persson, Svenskt Gastekniskt Center (SGC), November 2003.

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83 BIOMASS GASIFIER, PRE-GASIFIER TO BOILERS

Brief technology description
A gasifier produces a combustible synthetic gas (syngas) from a fuel. In a low-temperature gasifier, it is easy to use high alkaline containing fuels, as the gasifier operates below the melting point of those. This encompasses low grade biomass, such as agricultural residues, energy crops and certain waste fractions.

A simple application is co-firing biomass and coal in power plants. By using a biomass gasifier, the bio ash is separated, instead of being mixed with coal ash, thus keeping the nutrients in a usable form, and allowing the coal ash to be used for cement production. Furthermore, the syngas, comprising tar and fine dust, may be combusted directly in the boiler, without expensive gas treatment.

Please note that the description of this technology may not be fully representative of its generic characteristics, as all information originates from a single equipment supplier, the Danish company DONG Energy, who markets its product under the trade name Pyroneer[5].

The Pyroneer gasifier typically consists of three main components; a pyrolysis chamber, a char reactor and a recirculating cyclone. Cleaning the gas may simply be done with a second cyclone.

Fuel enters the pyrolysis chamber, where the fuel particles are pyrolysed at approximately 650°C upon contact with sand and ash particles. The pyrolysis chamber is a Circulating Fluid Bed gasifier. The low pyrolysis temperature and residence time results in the formation of only light tars.

The residual char and the pyrolysis gases are blown upwards to the 1st cyclone. This cyclone separates the sand and char particles to a char reactor, where the char is gasified. The gases generated in the char reactor is recycled to the pyrolysis chamber. The gases leaving the first cyclone continue to the 2nd cyclone. This cyclone is more efficient than the 1st cyclone and therefore most of the finest ash particles are separated out here. In this way it is possible to retain 90-95% of the ash. The remaining dust may be removed by adding a hot-gas filter operating above the tar dew-point.

The char reactor is a bubbling bed reactor, where the char is gasified at approximately 730°C using mainly air.

[5] Another supplier is the Finnish company Metso, who supplies biomass gasifiers up to 150 MJ/s.

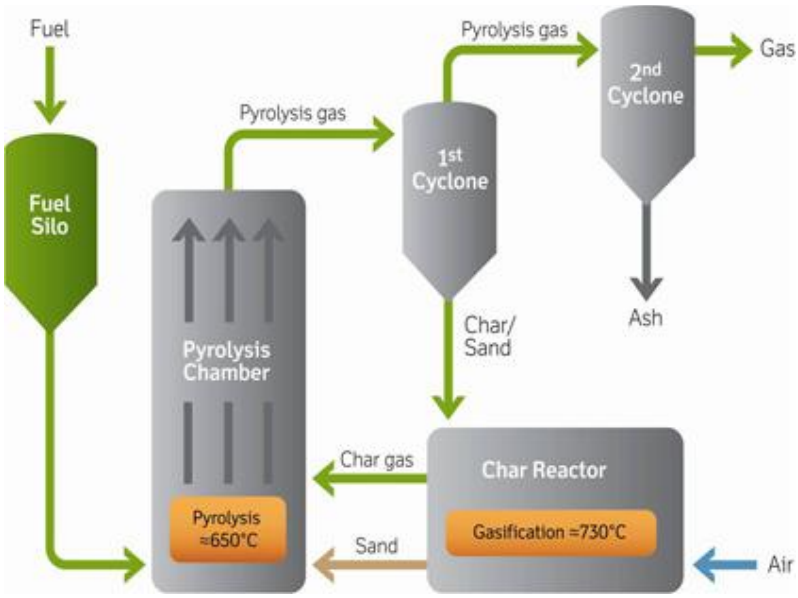


Figure 1: Process diagram (ref. 2).

Input
Low grade biomass.
Steam from the power plant's steam cycle.

Output
Synthetic gas (syngas)

The lower heating value of the wet gas is 5.9 MJ/kg, while the higher heating value is 7.6 MJ/Nm^3 (ref. 2).

Typical capacities
Nothing is yet typical, but two application areas are considered (ref. 2):

- Utility scale at 50-150 MJ/s (syngas)
- Industrial scale at 10-20 MJ/s

Advantages/disadvantages
Fuel flexibility: A large variety of difficult and low value fuels can be gasified, while not compromising a stable and reliable production of combustible gas.

Easy gas cleaning**:** Ash components such as potassium (K) and phosphorous (P) can be efficiently separated.

Recycling of nutrients**:** By keeping especially K and P in the non-sintered ash, it is possible to recycle these valuable nutrients to agriculture. Furthermore, a low content of heavy polyaromates (PAH) often allow the ash to be returned directly to e.g. farm land.

Scalability**:** The low temperature gasifier is based on CFB technology and thus fully scalable allowing great flexibility for adapting it to different uses.

Examples of best available technology

The Low Temperature Circulating Fluidized Bed (LT-CFB) process was invented by Peder Stoholm, Danish Fluid Bed Technologies (DFBT), in the 1990's. In 2009 DONG Energy acquired DFBT's rights and related knowhow, and renamed the technology Pyroneer.

A 6 MW Low Temperature Gasifier is constructed and commissioned at the DONG Energy owned coal-fired Asnaes Power Plant, unit 2. The demonstration will primarily gasify straw, 1.5 tonnes per hour, yielding 2,000 m^3/hour of syngas (6 MJ/s). Several other fuels is however also expected to be gasifed, in order to demonstrate the fuel flexibility. This demonstration project is expected to be completed 2013-14. A commercial scale demo-plant of 50 – 100 MJ/s is presently being investigated, and is expected to be commissioned in 2015 (ref. 2).

Environment

In general all the char is converted in the char reactor as previously described. A minor part of the Char will however escape from the 1st cyclone and afterwards be retained in the 2nd cyclone and then end up in the fly ash, or it will also escape the 2nd cyclone and be combusted with the gas in the coal boiler. Due to the high efficiency of the gasifier concept, the amount of char escaping the 1st cyclone will be very limited.

The ash, which contains all the alkaline salts present in the biomass and some char, will be distributed on farmland as a fertiliser.

Additional remarks

Main consumption figures for a 50 MJ/s gasfifier (ref. 2):

Fuel, straw	: 12.4	tonnes/hr
Gasification air	: 11.9	tonnes/hr
Steam	: 0.9	tonnes/hr
Sand, bed material	: 0.2	tonnes/hr
Electrical power	: 750	kW

References

1. “LTCFB demonstration plant”, ForskEL project no. 2009-10267, DONG Energy, September 2010.
2. DONG Energy, November 2011.

Data sheet

Technology	Biomass gasifier, pre-gasifier for boilers					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generation capacity for one unit (MJ/s syngas)	100	100	100	100		1
Efficiency, fuel to gas (%)	95	95	95	95		1
Avalability (%)						
Technical lifetime (years)	25	25	25	25		1
Construction time (years)	2	2	2	2		1
Environment						
NO_X (g per GJ fuel)					A	
CH4 (g per GJ fuel)						
N2O (g per GJ fuel)						
Financial data						
Specific investment costs (M€ per MJ/s fuel)	0,5	0,4	0,3	0,3		1
Total O&M (€ per MWh fuel)	2.4	2.4	2.4	2.4	B	1

References:

1 DONG Energy, November 2011

Notes:

A Depends on how the gas afterwards is combusted, but most likely similar to coal combustion, cf. Technology element 01.

B Exclusive fuel

84 GASIFIER, BIOMASS, UPDRAFT

Brief technology description
A solid biomass fuel is converted into gas, which in turn is used in boilers, gas engines, Stirling engines or gas turbines for power and heat production, or as substitute for fossil fuels in industrial processes.

The biomass is converted through several stages. Up to 100°C the water is vaporized. By pyrolysis (extra heating and limited addition of oxygen) the dry fuel is converted to a tarry gas and a coke residue. Subsequently, the coke residue is gasified at 800-1200°C, while water vapour and/or oxygen (air) is added. Depending on the process, the tar shall either be incinerated or cracked before it is cleaned of particles etc.

The updraft (or counter current) gasifier is characterised by the fuel and the gas having opposite flow directions. The gas has low temperature (~75°C) but a large content of tar, typically 30-100g/Nm^3. The updraft gasifier has been used for the last 75-100 years for electricity, heat, steam and industrial processes such as burning of ceramics, glass making, drying and town gas (ref. 2).

The raw gas leaving the gasifier is often called producer gas, while gas, which has been cleaned from impurities, is called syngas (brief from synthetic gas).

Input
Wood chips, pellets, chunks and briquettes, industrial wood residues, demolition wood and energy crops can be used. Requirements to moisture content and size of the fuel are depending on the design of the reactor and the process.

Output
Producer gas primarily consists of the components CH_4, H_2, CO, CO_2, N_2, H_2O and tar with a lower heating value of 6.6 – 6.8 MJ/Nm^3 for the dry cleaned gas (ref. 2).

Typical capacities
0.2 - 10 MJ/s fuel.

Since the economy-of-scale is moderate, this gasifier is well suited for modular plants. Each module can then be tailored to a specific fuel.

Regulation ability
At Harboøre tests have shown that the load can be changed from 10 to 100 % and vice versa within a few minutes, which is not possible in a conventional wood chip boiler (ref. 2).

Advantages/disadvantages
The updraft gasifier has limited requirements to fuel quality, i.e. the contents of moisture and ash. Furthermore, the gasifier is capable of ramping up and down thereby offering flexibility both in relation to industrial applications and for supplying heat to district heating grids.

Environment
The electricity efficiency is higher than combustion technologies, in the low capacity range. Thus, emissions are less - relative to electricity generation.

Research, development and demonstration
The Danish development activities for smaller gasification plants focus on a few development tracks. Priority is to conduct long-term tests in pilot size and demonstration of few technologies. In connection with this R&D is carried out, which is expected to solve operational problems such as corrosion, process regulation etc.

The main issues to be addressed to achieve market deployment of biomass gasification include:

- Ability to handle a wider range of fuel properties in particular waste wood and other biomass residues.
- Establishing references of up-draft gasification plants for waste wood and other biomass residues to drive the incremental development and facilitate export of Danish technology.

Other issues that should be addressed to support biomass gasification:

- Purification of wastewater with tar in; in particular capital cost reduction
- Meeting emissions regulations
- Reactor calculations; kinetic models of significance for design and control

The counter current gasification technology is ready for a broader market introduction.

Examples of best available technology
Examples of gasifiers based on Danish technologies:

- At Harboøre a 3.6 MJ/s updraft counter-current moving bed gasifier was installed in 1994. The gasifier is used for CHP production and has a gross electrical output of 1.0 MW. The gasifier utilises woodchips. The gasifier is operated by Babcock & Wilcox Volund A/S.
- In Japan three counter-current moving bed gasifiers have been installed in 2007-09 with capacities ranging from 8 to 11 MJ/s. The plants were installed by JFE corporation based on a license from Babcock & Wilcox Volund A/S (ref. 2).
- Some counter-current fixed bed gasifiers producing gas to Stirling engines were commissioned in Denmark during 2009, cf. Technology sheet 10.

Notably USA, Denmark, Germany, Sweden, Austria, and Finland are involved in developing biomass gasification processes. The European Commission framework programmes for R&D support gasification as well as national programmes in a number of countries.

References

1. ”Biomasse kraftvarme udviklingskortlægning” (R&D mapping of biomass cogeneration; in Danish). Summary report. Eltra, Elkraft System, and Danish Energy Agency, 2003
2. Babcock and Wilcox Volund (BWV), November 2009.

3. ”Strategi for forskning, udvikling og demonstration af biomasseteknologi til el- og kraftvarmeproduktion i Danmark” (Strategy for RD&D in biomass cogeneration in Denmark; in Danish). Danish Energy Agency, Elkraft System og Eltra, 2003.
4. ”El från nya anläggningar – Jämförelse mellen olika tekniker för elgenerering med avseende på kostnader och utvecklingstendenser” (Benchmarking of new electricity generating technologies; in Swedish). Bärring et al. Elforsk Report no. 00:01. 2000.

Data sheet

Technology	Updraft counter-current fixed bed gasifier with CHP plant (engine)					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	1.4					1
Total efficiency (%) net	105				A	1
Electricity efficiency (%) gross	26-27					5
Electricity efficiency (%) net						
Time for varm start-up (hours)	0.25					3
Forced outage (%)	5					2
Planned outage (weeks per year)	3					2
Technical lifetime (years)	20					2
Construction time (years)	1.5					2
Environment						
SO_2 (degree of desulphoring, %)						
NO_X (g per GJ fuel)	100					2
CH4 (g per GJ fuel)	20					2
N2O (g per GJ fuel)						2
Financial data						
Specific investment (M€/MW)	3.7				B	2
Fixed O&M (€/MW/year)	185000				B	2
Variable O&M (€/MWh)	19				B	2
Regulation ability						
Fast reserve (MW per 15 minutes)	1.4					2
Minimum load (% of full load)	10%					2

References:

1 Danish Energy Agency, 2003.

2 Bjørn Teislev, R&D Manager, Babcock and Wilcox Volund (BWV), personal communication, 2003

3 Danish Technology Institute: "Udvikling af computerbaseret værktøj, energyPRO, til simulering og optimering af driftsstrategi for biobrændselsfyrede kraftvarmeværker", September 2001

5 Babcock and Wilcox Volund, 2009.

Notes:

A 105% efficiency is with flue-gas condensation (e.g. wood chips as fuel); without the efficiency is around 85%

B Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying with a general inflation factor 1.2306

85 GASIFIERS, BIOMASS, STAGED DOWN-DRAFT

Brief technology description
A solid biomass fuel is converted into gas (producer gas), which can be used in gas engines, boilers, gas turbines or fuel cells for power and heat production. The data in this technology sheet are for a system including a gas engine.

The biomass is converted through several stages. Up to 100°C the water is vaporized. By pyrolysis the dry fuel is converted to a tarry gas and a char residue. Subsequently, the char residue is gasified at 800-1200°C, while water vapour and/or oxygen (air) is added.

In staged gasification, pyrolysis and gasification are separated into two reactors, enabling a partial oxidisation of tar products between the stages. Thus, staged gasifiers are producing a gas with low tar content, which is essential for engine operation. The tar content is often below 100 mg/Nm^3 and can be below 10 mg/Nm^3.

The pyrolysis process can be with either internal or external heating. Internal heating is performed by addition of air/oxygen, while external heating utilises waste heat from the produced gas and from the engine to dry and pyrolyse the fuel. The data in the table are valid for external heating, as this results in higher efficiencies.

Input
Wood chips (collected in forests), industrial wood residues, straw and energy crops can be used in the form of chips, briquettes or pellets. Requirements to moisture content and size of the fuel are depending on the design of the reactor and the process.

Output
Producer gas primarily consists of the components N_2, H_2, CO, CO_2, CH_4, and water. The lower heating value of the gas is 4.5-6.5 MJ/Nm^3. The gas is converted to electricity and heat by a gas engine.

Typical capacities
The attractive market segment is for plants with fuel inputs around 1-20 MJ/s.
The economy-of-scale is important.

Regulation ability
It can be fully regulated within a few seconds.

Advantages/disadvantages compared to other technologies
Gasification of biomass for use in decentralized combined heat and power production can decrease the emission level compared to power production with direct combustion and a steam cycle.

Existing natural gas fuelled engines can be converted to use 100% producer gas or a combination of producer gas and natural gas.

One disadvantage is long start-up time (from cold). Also, excessive soot-formation may occur at start/stop.

Environment:
Ashes from gasification of wood contain most of the cadmium that was in the wood. Therefore, spreading of ashes in forests or on agricultural land shall be carried out with considerable caution.

Research and development¨

- Scale up
- Load regulation; incl. automatic start/stop
- Further automation and safety documentation
- Optimised engine operation
- Low temperature corrosion; materials
- Soot formation

Examples of best available technology

1) The company Weiss (www.weiss-as.dk) established in 2009 a 500 kW demonstration plant (fully automated) in Hadsund, Denmark.
2) Bio Synergi (www.biosynergi.dk): The Græsted pilot project (450 kJ/s fuel).

Data sheet:

Technology	Gasifiers, biomass, staged down-draft					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	1-10	1-20	1-20			1
Total efficiency (%) net	103	105	105		A	1
Electricity efficiency (%) net - 100% load	35 - 40	37 - 45	37 - 45		A	1
Start-up fuel consumption (GJ)						
Cb coefficient (40°C/80°C)	0.6	0.7	0.7			1
Availability (%)	95	97	97			1
Technical lifetime (years)	15 - 20	20	20			1
Construction time (years)	1	1	1			1
Environment						
SO_2 (degree of desulphurisation, %)						
SO_2 (g per GJ fuel)	0	0	0			1
NO_X (g per GJ fuel)	100	100	100			1
CH4 (g per GJ fuel)						
N2O (g per GJ fuel)						
Financial data						
Specific investment (M€/MW)	3.4-3.7	2.5-3.0	2.4-3.0		C+D	1+2
Fixed O&M (€/MW/year)	69000	57000	57000		C	1
Variable O&M (€/MWh)	18	17	17		C	1
Regulation ability						
Minimum load (% of full load)	10	10	10			1

References:

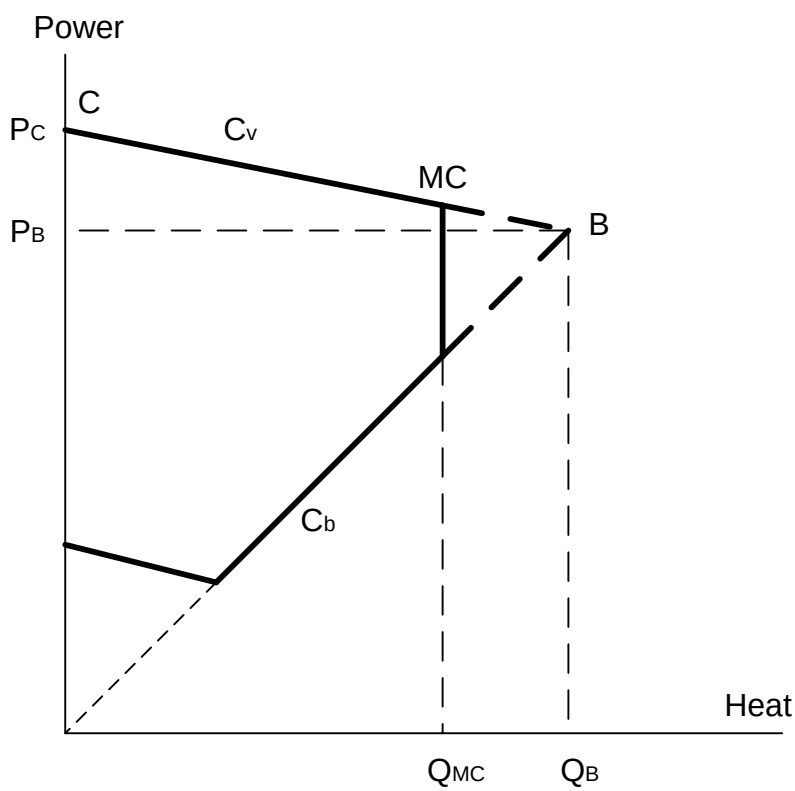
1 Weiss A/S and Biomass Gasification Group, Technical University of Denmark, November 2009.
2 TK Energi, November 2004
3 "Potential contribution of bioenergy to the World's future energy demand", International Energy Agency, 2007.

Notes:

A With external heating of the pyrolysis process through waste heat recovery
B Calculated from < 1 mg/m³ assuming this value refers to dry flue gas at 6% oxygen
C Cost data are the same as in the 2005 catalogue, however inflated from price level 2002 to 2011 by multiplying with a general inflation factor 1.2306
D Ref. 3 quotes a price of 1000-3000 €/kW (2006) for small (0.1-1 MW) gasification plants, no mention of specific technology. This translates to 1.1-3.2 M€/MW in 2008 prices.

ANNEX 1: FEATURES OF STEAM EXTRACTION TURBINES

With an extraction steam turbine, all steam may be condensed (e.g. by sea water) to generate maximum electricity (P_C), or all steam may be extracted to be condensed at a higher temperature to generate district heat (Q_B). In the latter case, full back-pressure mode (point B in the below figure), some electricity generation is lost ($P_C – P_B$).



With the steam boiler at full capacity, the turbine may be operated at all points along the line C-B. In the real world, C-B may not be a straight line, but a linear relationship is a good proxy.

By varying full input and steam extraction, the generation of electricity and heat may in theory be varied within the area limited by lines C-B and origo-B. However, in practice there is a minimum power generation capacity (e.g. 10-20% of P_C), and the maximum heat generation capacity may be lower than Q_B.

Below, some relationships are given for key variables.

P_C: Power capacity in full condensation mode; point C. No heat production.

$\eta_{e,c}$: Electricity efficiency in full condensation mode.

Q_B: Heat capacity in full back-pressure mode (no low-pressure condensation); point B.

P_B: Power capacity in full back-pressure mode.

Q_{MC}: Heat capacity at minimum low-pressure condensation; point MC.

c_v: Loss of electricity generation per unit of heat generated at fixed fuel input; assumed constant.

c_b: Back-pressure coefficient (electricity divided by heat); assumed constant.

The fuel consumption H for any given combination of power generation (P) and heat generation (Q):

$$H = \frac{P + c_v \cdot Q}{\eta_{e,c}}$$

$\eta_{e,B}$: Electricity efficiency in full back-pressure mode:

$$\eta_{e,B} = \eta_{e,c} \cdot \frac{c_b}{c_b + c_v}$$

$\eta_{q,B}$: Heat efficiency in full back-pressure mode:

$$\eta_{q,B} = \frac{\eta_{e,c}}{c_b + c_v}$$

$\eta_{tot,B}$: Total efficiency (electricity plus heat) in full back-pressure mode:

$$\eta_{tot,B} = \eta_{e,c} \cdot \frac{1 + c_b}{c_b + c_v}$$

$\eta_{e,MC}$: Electricity efficiency at minimum low-pressure condensation:

$$\eta_{e,MC} = \eta_{e,c} \cdot \left\{1 - \frac{c_v}{c_b + c_v} \cdot \frac{Q_{MC}}{Q_B}\right\}$$

$\eta_{q,MC}$: Heat efficiency at minimum low-pressure condensation:

$$\eta_{q,MC} = \frac{\eta_{e,c}}{c_b + c_v} \cdot \frac{Q_{MC}}{Q_B}$$

$\eta_{tot,MC}$: Total efficiency (electricity plus heat) at minimum low-pressure condensation:

$$\eta_{tot,MC} = \eta_{e,c} \cdot \left\{1 + \frac{1 - c_v}{c_b + c_v} \cdot \frac{Q_{MC}}{Q_B}\right\}$$

<u>Example:</u>

Electricity efficiency in full condensation mode = 45%, c_v = 0.15, c_b = 1 and Q_{MC}/Q_B = 0.7.

This gives the following values in point B:
Electricity efficiency = 39.1%
Heat efficiency = 39.1%
Total efficiency = 78.3%

While in point MC:
Electricity efficiency = 40.9%
Heat efficiency = 27.4%
Total efficiency = 68.3%