Electricity from new and future plants 2014

Elforsk report 14:45

Ingrid Nohlgren, Solvie Herstad Svärd, Marcus Jansson, Jennie Rodin

October 2014

ELFORSK

Electricity from new and future plants 2014

Elforsk report 14:45

This is a translation from Swedish of the Elforsk report 14:40 El från nya och framtida anläggningar 2014.

Ingrid Nohlgren, Solvie Herstad Svärd, Marcus Jansson, Jennie Rodin
October 2014

Foreword

The aim of the project “Electricity from new and future plants 2014” is to provide an up to date and authoritative description of the different electricity generation technologies and their generation costs. This report serves as a snapshot and does not make an assessment of the future potential of the various technologies. It is important to be aware that each technology has limitations and specific conditions and that one energy source cannot easily be replaced by or even be compared with another. Additionally, there are system aspects to take into account that this project has not made any detailed reports about.

The project includes a web application where the user can set parameters for different power sources, save the results and download diagrams. The web application is accessed via the Elforsk website and assumes that the user has access to this report.

The project has been carried out by WSP on behalf of Elforsk. The assignment from Elforsk in turn has been ordered by AB Fortum Värme which is jointly owned by the City of Stockholm, Borås Energi och Miljö AB, E.ON Sverige AB, Göteborg Energi AB, Jämtkraft AB, Karlstads Energi AB, Mälarenergi AB, Skellefteå Kraft AB, Svensk Vindenergi ek.förening, Tekniska verken i Linköping AB, Umeå Energi AB, Vattenfall AB and Öresundskraft Kraft och Värme AB. The Swedish Energy Agency has been a supporter of the project.

The Project Manager at WSP was Ingrid Nohlgren and the project team included Solvie Herstad Svärd, Marcus Jansson and Jennie Rodin. Other team members who contributed: Anna Molker for her work on taxes and natural gas based technologies, Ola Trulsson for his work on wind power and Roger Hamrén has developed the web-based calculation application.

The project's Steering Group has consisted of Björn Fredriksson Möller (E.ON), Anton Steen (Svensk Vindenergi), Marcus Bennstam (Tekniska verken Linköping), Mikael Sandberg (Fortum Värme), Anna Lejestrand (Svensk Energi), Magnus Berg (Vattenfall), Håkan Carefall (Skellefteå Kraft), Daniel Andersson (Energimyndigheten), Joacim Sundqvist (Mälarenergi), Ulf Hagman (Göteborg Energi).

In addition to the Steering Group, a broader group has provided valuable feedback. This group includes Charlotta Winkler (WSP), Magnus Holmgren (WSP), Jonas Lindström (WSP), Bengt Stridh (ABB), Johan Lindahl (Uppsala University), Hans Ohlsson (wpd), Mattias Lantz (Uppsala University), Harald Klomp (UEP).
The Project Manager at Elforsk has been Anders Björck.

This report is the fifth issue since Elforsk began publishing “Electricity from new plants” in 2000. The ambition is to continue to update the report about every three years.

Stockholm, October 2014
Helena Sellerholm, Elforsk AB

Summary

Targets and target group

The first version of “Electricity from new plants” was published in 2000. Since then, the report has been updated in 2003, 2007 and 2011. This report is a revision and update of previous reports. The project has been carried out with the following overall targets:

- Provide a comprehensive, relevant and comparable picture of electricity generation costs for commercially[1] available technologies with a description and account of the factors affecting the electricity generation costs.
- Provide a description of development trends for both commercially available technologies as well as for a number of technologies that may be commercially viable in a decade.
- Create a web-based calculation application for managing and presenting electricity generation costs as well as for sensitivity analyses with respect to the essential factors and pre-conditions.

The results can be used for planning and preliminary feasibility studies. The results have a wide target group:

- A section of the target group includes professional organisations, interest organisations, politicians and government agencies. The results of the report will be used by these target groups as an authoritative description of the technologies and their electricity generation costs.
- Another target group is the power companies. Through the report and project's calculation application they will be able to make estimates of electricity generation costs in a range of studies.

Delimitations

The project is limited to a number of power sources and plant sizes. The commercial power sources that are covered are condensing power (coal and natural gas based), co-generation (natural gas, biomass and waste-derivatives), nuclear power, wind power, hydroelectric and solar power. The studied semi-commercial electricity generation technologies are gasification (RDF and biomass-based) and a residual heat ORC plant. The future technologies studied are wave energy, CCS technologies with coal and gas condensing, and biomass gasification in a combined cycle.

The electricity generation costs for each plant are calculated based on the specific input data per plant and the general preconditions. For commercially available technologies, the best possible technical, economic and environmental data that can be considered as representative of today's national and international market has been used. The costs include complete plants with

[1] Commercial technology options referred to in this report are plants that can be procured commercially with warranties.

everything from fuel handling systems to emission control systems and include internal infrastructure, internal electrical and heating systems and connection to the electricity and district heating grid at the plant's "gate". Investments outside the plant, for example, infrastructure, electricity and district heating are not included as a rule, except to some extent for wind power. Generally, all project-specific costs in the estimated electricity generation costs have been included.

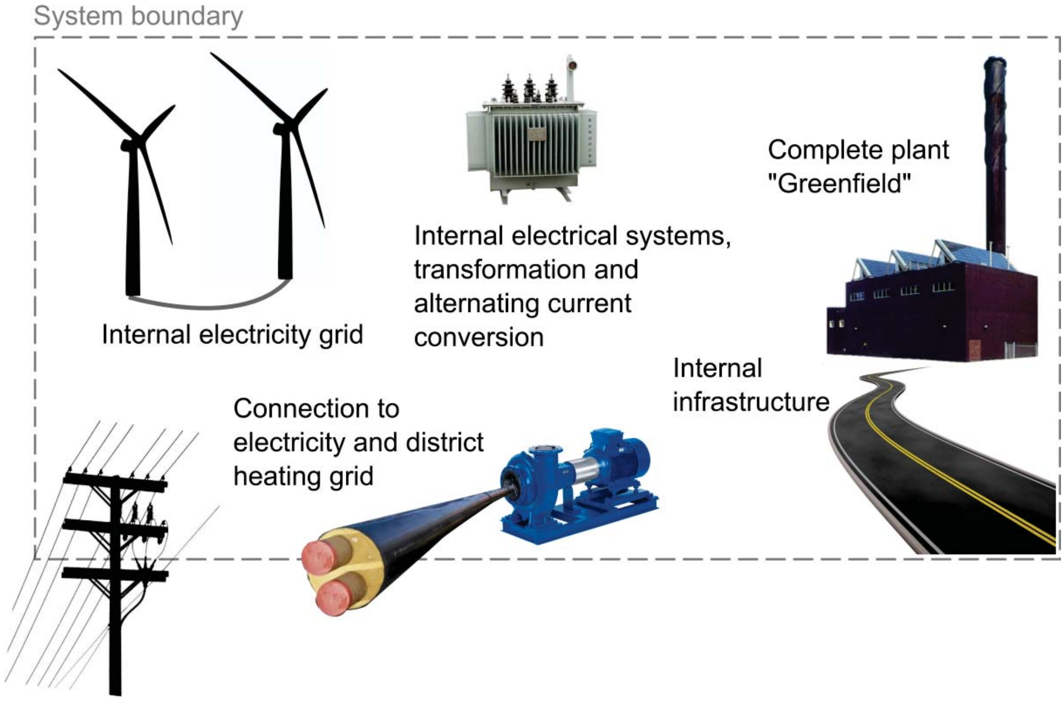

Figure I. Principal figure with system constraints on investment costs.

Additionally, no account has been taken of any political factors, such as delays in projects stemming from political decisions, appeals of environmental judgements or detail planning issues. Obviously this is something that could affect a project's schedule and entail costs as a result. The electricity generation costs presented in this report therefore assume that the project proceeds "normally" under its construction.

Finally, the premise of the project has been that all electricity is generated in compliance with today's electrical systems and the changes that might affect today's electrical systems are marginal (i.e. does not account for long-term changes in installed capacity for different power sources). This includes, among other things, that no account has been taken to the possible costs of installing power that can balance intermittent power sources such as solar and wind power, which could be relevant in a future electricity system where a larger share of electricity is generated using solar and wind power.

Preconditions

The electricity generation costs for each plant are calculated based on the specific input data per plant and the general preconditions.

Fuel prices and taxes

This report is not designed to evaluate governing factors such as trends in policy instruments or the development of fuel prices, but it is today's price levels that have been applied. Fuel prices and calorific values have been taken from various official sources, such as Energy in Sweden 2013 (Energiläget 2013) and the Swedish Energy Agency's price sheet for peat and biomass. Data was also collected from users and fuel suppliers.

The calculations have been conducted based on the tax rate that is applicable under current legislation.

Electricity certificates

The price trend for electricity certificates has a significant impact on new renewable electricity generation. In this process, an average of the last year's price of certificates has been applied.

Investment costs and costs of operation and maintenance

The investment costs consist of all the parts of a complete installation. Investments relating to the construction of the “standard mode”, i.e. the specific investment costs do not consider special localisation-related costs. For wind power, however, a “standard investment” in infrastructure and power grids is included. To ensure representative investment levels, the compiled information regarding constructed and projected plants in Sweden and the Nordic countries has been used. This refers primarily to plant types that have been implemented in the Nordic countries: biomass and waste-fired co-generation plants, gas co-generation fired plants and nuclear, wind and solar power plants. Valuable information has also been collected from research reports, national and international professional organisations, international cooperation agencies, annual reports and more. Information has also been collected from suppliers and via the steering committee's contacts in their own companies and in the networks where research is conducted in this field.

Operating and maintenance costs are generally presented as a fixed and a variable component. Operating and maintenance costs are based on standard values taken from the literature data, available statistics and/or calculations made based on plant data. Reconciliations have been made using data from the operation of specific plants and the project's steering committee.

Heat crediting

In a co-generation power plant, where electricity and heat are generated simultaneously, the co-generated and usable heat must be attributed a value when calculating, i.e. all costs of generation in the co-generation plant cannot be attributed to the generation of electricity. This report estimates the cost of electricity generation for co-generation power plants by subtracting the cost of producing district heating from the total generation costs for producing both electricity and heat. This method of heat crediting is called fixed crediting, which can be applied when, as in this report, it concerns new investment in a district heating system, i.e. if a co-generation plant had not been built, a heating plant would have been built instead.

The cost of producing district heating is calculated based on an alternative investment in a biofuel-fired hot water plant with an equivalent heat output as a co-generation plant, along with the fuel, operating and maintenance costs of a hot water plant. The cost of generating heat varies with the size of the hot water plant leading to different heat crediting for different sizes of plant.

Note that heat crediting as above is a generalisation of reality and the real heat generation costs for the specific case are due to the conditions prevailing in the current district heating grid. Heat crediting has a major impact on electricity generation costs and can be modified in the calculation application for internal analyses.

Financial calculation conditions
Calculation of the electricity generation costs (and, where appropriate, heat) were made with and without taxes, fees and contributions as stated in the annuity method. The actual cost of capital (6%) must be equivalent to a “Weighted Average Cost of Capital” (WACC), which reflects a combination of the real rate of return on the plant owner's equity and interest rates on loans. A construction interest rate of 4% should not be burdened with a profit requirement and risks in the project, but should be assumed to be interest on loans. The plant's economic life (depreciation) is not only dependent on technical quality and maintenance, but also on factors such as technological development, fuel prices, tax effects, environmental costs, etc. However, in this report a reasonable technical lifetime has as far as possible been considered, and this varies from 15 years for smaller plants to 40 years for nuclear and hydroelectric power plants.

Technical specifications
The technical specifications for the technologies included in the report are based on existing plants or plants under construction. Where technologies are represented in Sweden, Swedish plants are used as the base. For technologies that are not being pursued in Sweden, specifications from international plants have been used, for example, for coal condensing, gas combination condensing and new nuclear power plants.

Operating conditions
The annual electricity generation, i.e. the amount of electricity supplied to the grid, is calculated from the plant's electrical output and uptime. This is done regardless of whether the demand for electricity varies throughout the year. This means the condensing power plant can be estimated to run as much as is technically possible. It is important to note that this assumption is not necessarily the one that prevails in reality. In an electrical system, power sources with high variable costs are usually forced to the margins by other generation with low variable costs. This leads, for example, to gas condensing power plants actually running considerably less than what is technically possible.
The generation of solar power is controlled by the prevailing solar conditions where the average normal solar incident radiation for Sweden has been used. Wind turbine power generation is controlled by the wind conditions at the site. Hydroelectric power is used in Sweden as both base and peak power depending on the prevailing conditions, where in the watercourse the power plant is

located. An estimate of the number of full load hours for hydroelectric power has been made by dividing Sweden's total electricity generation over a normal year with the total installed capacity.

Co-generation is dependent on local demand for district heating and for the co-generation-based technologies therefore take into account the provision for heat varying over the year.

Co-generation by burning household and industrial waste is, in addition to the district heating source, also dependent on the fact that the waste cannot be stored for a long time in hot weather. This type of co-generation plant often acts as a base load in a district heating system and therefore is expected to have more than the equivalent full load hours of a co-generation plant.

Calculation application

The calculation application, which is available on Elforsk's website http://www.elforsk.se, calculates the electricity generation costs for specified plant options according to the annuity method with pre-specified input data. The calculation results are presented in tabular and graphic format and, together with the associated input table, are exported to Excel format. The user specifies which of the plants are to be included in the calculations, and can freely modify the input data for each plant option.

The calculation application has been developed for the individual plant owner or the reader who wants to adapt certain conditions or input data, or is interested in conducting more detailed sensitivity analyses than those presented in the report. Examples of input data that may need to be adapted to suit different conditions are interest rates, which vary with the power source, risk assessments and ownership structure.

Results

The presentation of results has been divided into commercial and semi-commercial technologies. Regarding future technologies, we refer you to the report. The results are presented for cases with a cost of capital of 6 and 10 % respectively, and with and without policy instruments. The influence of the costs of electricity generation from parameters such as cost of capital, depreciation period, investment costs, fuel prices and heat crediting are discussed below and are presented graphically in the report. For more parametric studies we refer you to the web-based calculation application.

Commercial technologies

Figures II and III show the cost of electricity generation for all commercial technologies excluding policy instruments with 6 and 10% cost of capital respectively. Figures IV and V show the cost of electricity generation for the same power source including policy instruments with 6 and 10% cost of capital respectively. The figures show, among other things, that waste generation, RDF combustion, and wind and hydroelectric power have the lowest electricity generation costs.

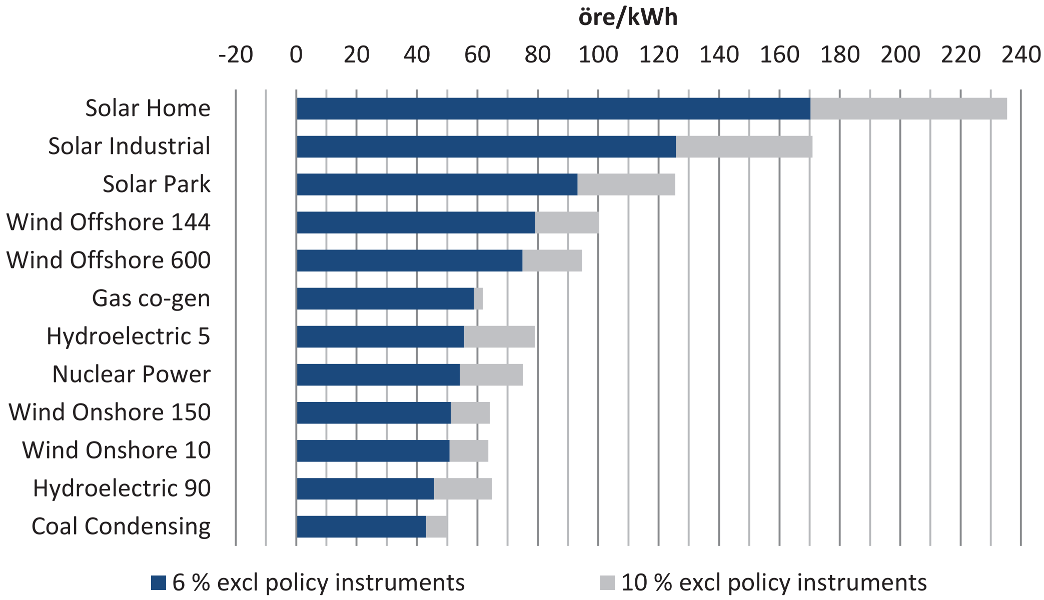

Figure II. The cost of electricity generation for commercial technologies that only generate electricity, excluding policy instruments with 6 and 10% cost of capital respectively.

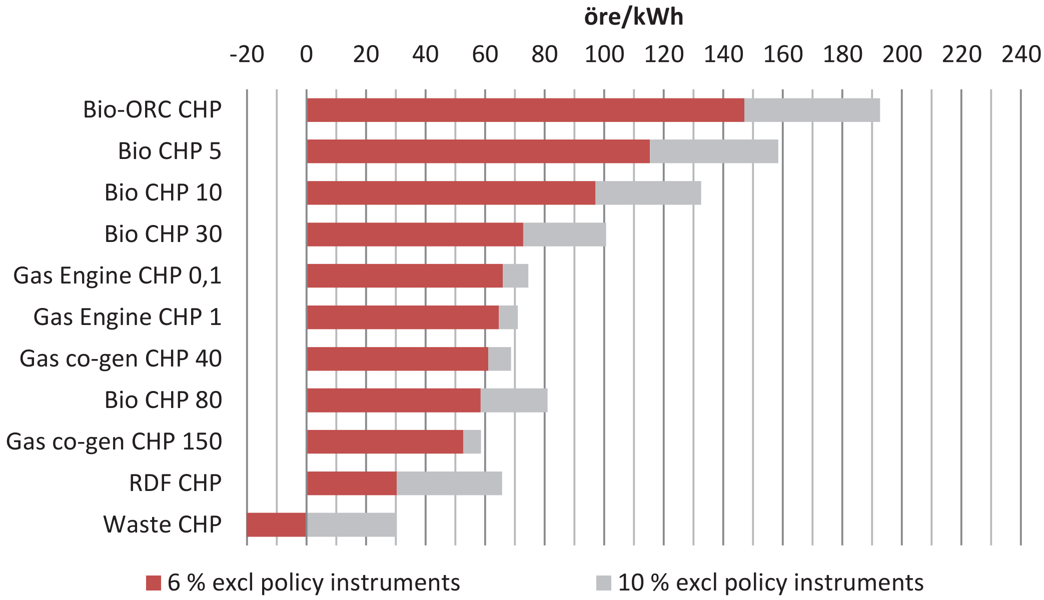

Figure III. The cost of electricity generation for commercial technologies that generate both electricity and heat, excluding policy instruments with 6 and 10% cost of capital respectively.

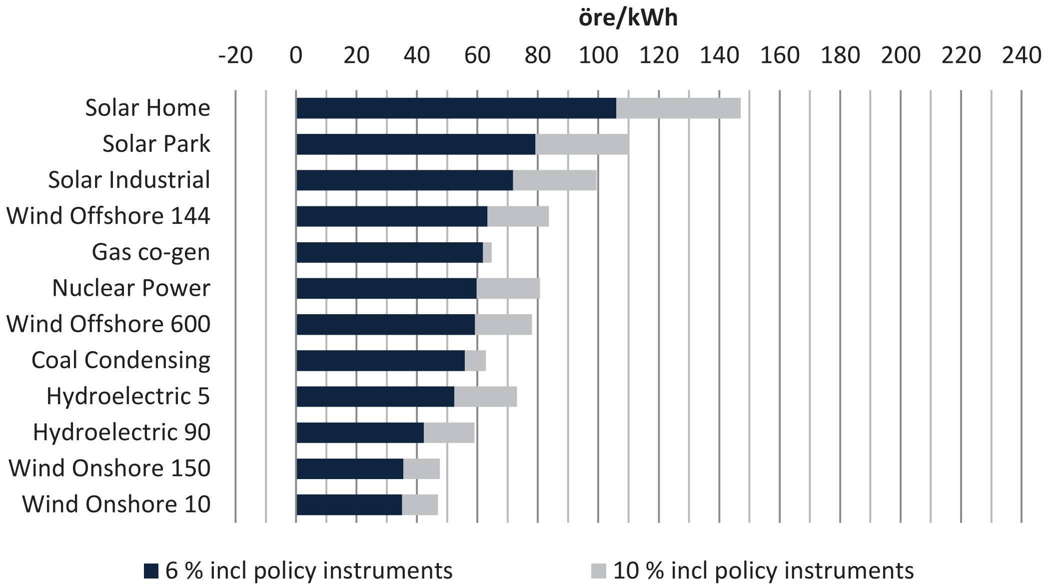

Figure IV. The cost of electricity generation for commercial technologies that only generate electricity, including policy instruments with 6 and 10% cost of capital respectively.

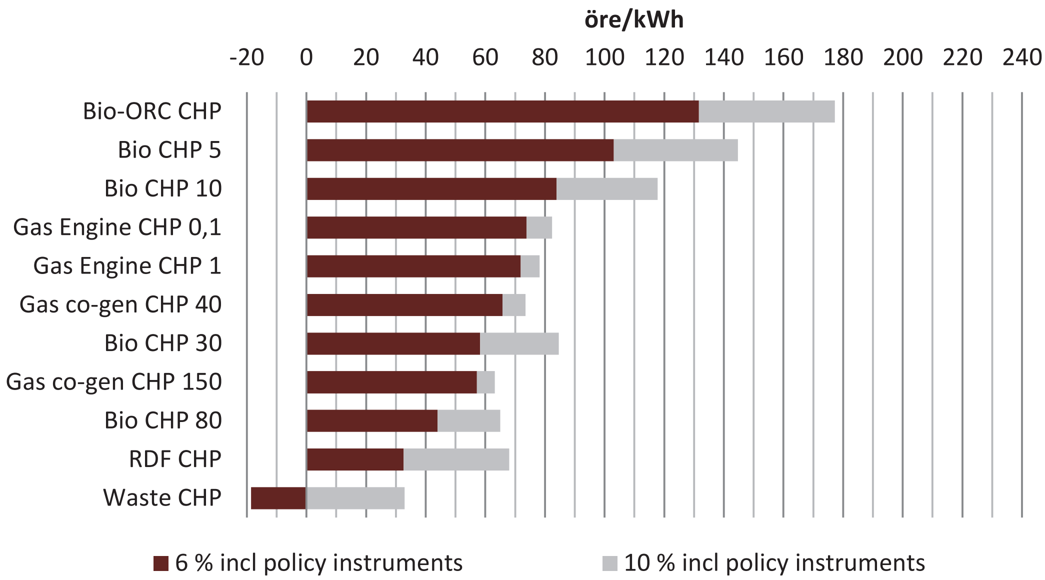

Figure V. The cost of electricity generation for commercial technologies that generate both electricity and heat, including policy instruments with 6 and 10% cost of capital respectively.

The cost of electricity generation is associated with greater uncertainties for certain power sources in the study than others based on the extent of input data available. New nuclear power plants have not been built, for example, in Europe for many years, which means that experiences about costs are few and the cost estimate are therefore more uncertain. In contrast, biomass-fired co-generation plants have been and are being built continuously and extensively in Sweden over recent years, which has generated a lot of supporting data for cost estimates, which are therefore much more certain. New nuclear and hydroelectric power plants are the power sources with the most uncertain costs for electricity generation.

Economic policy instruments in the form of taxes, fees and electricity certificates affect earnings significantly, which can be compared between Figure II and Figure IV for the power source that only generates electricity, and between Figure III and Figure V for co-generation technologies that generate both electricity and heat. Generally, fossil fuel power sources are penalised while renewable power sources are favoured. Clear examples where policy instruments have a major effect on electricity generation costs are wind power and coal condensing. Note that taxes and fees related to the management of residual waste from nuclear power and waste tax for other technologies (also known as landfill tax) have been included in the O&M costs as detailed in Chapter 3.8, these taxes and fees are also included in those cases where electricity generation costs are presented excluding policy instruments.

Waste-fired co-generation plants have the lowest electricity generation costs of all component technologies in the study. This is mainly because the fuel, both household and industrial waste, does not have a cost but a benefit, while the percentage of heat generated is very high, which generates significant revenue through heat crediting. It is important to note that the waste-fired co-generation plants are primarily being built to generate heat and therefore require a local demand for heating. Without heat crediting, electricity generation costs are very high, above SEK 1.30/kWh, which would mean instead that waste-fired co-generation plants are one of the most expensive types of technology in the study.

Of the technologies that only generate electricity, coal condensing has the lowest electricity generation costs, where the calculation is performed without any economic policy instruments. When policy instruments are added, coal condensing is more expensive and onshore wind power has the lowest electricity generation cost, even before electricity certificates are included. Apart from the waste-based co-generation technologies, onshore based wind power has the lowest electricity generation costs with current policy instruments. However, note that any costs for power regulation have not been addressed in this report.

Biofuel fired co-generation plants show a clear size dependence where the electricity generation costs are lower the larger the plant is. Also here, it is important to point out that biofuel fired co-generation plants are fundamentally dependent on a heat source and that heat crediting is key for the electricity generation cost.

According to Figure IV wind power shows no clear size dependence between different plant sizes. It should be clarified that the cost of wind power is dependent on size for comparisons in one specific place. The reason for this size dependence not being evident in Figure IV is that the electricity generation costs displayed will not have been calculated for the same specific place but is based on average costs for new wind power plants. Smaller plants are usually built near to the power grid and where the wind conditions are good, whereas larger plants are often further away from the power grid and experience less favourable wind conditions. The various preconditions that plants have mean therefore that size dependence which is evident at the exact same place does not appear. However, the difference between onshore and offshore wind power is significant in the report.

The electricity generation costs of solar photovoltaic power plants have fallen significantly in recent years as a result of increased efficiency and decreasing investment costs for solar panels.

Semi-commercial technologies
The electricity generation costs for semi-commercial technologies are presented in Figure VI and Figure VII.

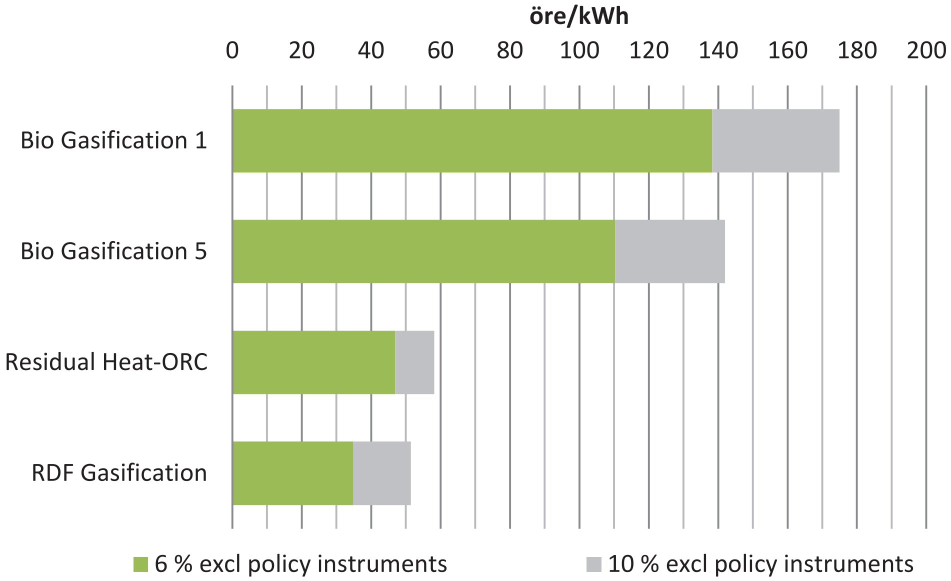

Figure VI. Electricity generation costs for semi-commercial technologies, excluding policy instruments with 6 and 10 % cost of capital respectively

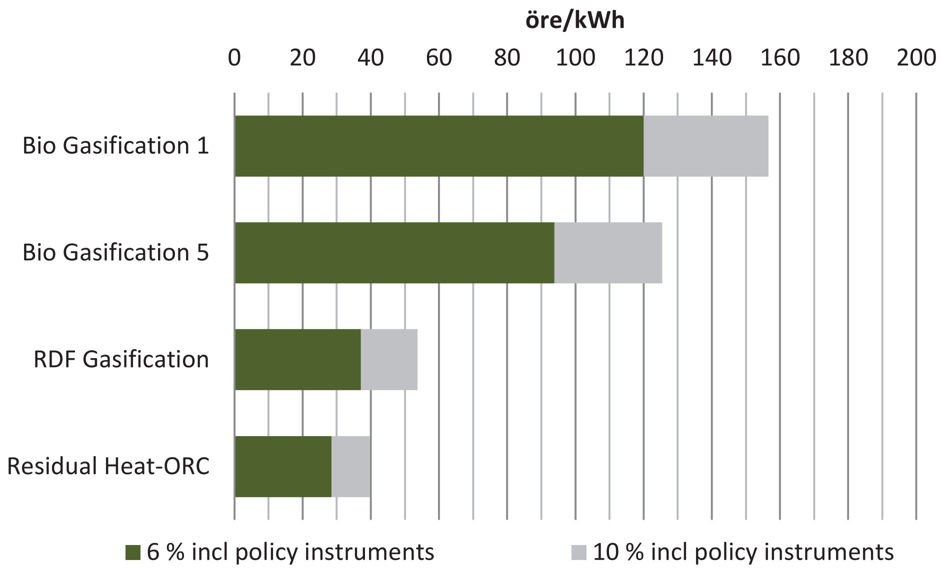

Figure VII. Electricity generation costs for semi-commercial technologies, including policy instruments with 6 and 10 % cost of capital respectively

As defined in this report, semi-commercial [2]technologies are new, and can probably be purchased with limited warranties. This means that the supporting data for the costs is limited while the calculation assumptions are based on expectations, particularly for uptime and availability.

The electricity certificate is the most important instrument among the semi-commercial power sources that reduce the cost of all of them except for RDF gasification which is not entitled to electricity certificates. Other policy instruments only affect the electricity generation costs marginally.

The electricity generation costs including policy instruments for a waste heat driven ORC plant are some of the lowest in the report, provided that free residual heat with a sufficiently high temperature is available throughout the year and at an availability rate of 95%. The technology is still in its infancy, and experiences from plants in operation provide an availability rate today that is well below 95%, which probably means that the O&M costs are also higher than assumed. The report considers that residual heat has originally come from a renewable fuel which entitles electricity certificates.

The electricity generation costs for biomass gasification with gas engine (BIG ICE) are heavily linked to the size of the plant. The smaller plant of 1 MW has a higher capital cost per installed kW_{el} and an electrical efficiency below 5 MW per plant which leads to almost 50% higher electricity generation costs for the smaller plant than the larger one. Compared to the 5 MW biofuel-fired co-generation power plant, the electricity generation costs are lower due to lower investment costs and the higher electrical efficiency of the gasification-based plant. The gasification plant works with lower quantities of air and is therefore

[2] Semi-commercial technologies referred to in this report are plants that can be purchased today but with limited warranties.

more compact than a corresponding gasification plant. Despite this, the technology has yet to take hold in Sweden. The reason for this may be the maturity of the technology especially regarding gas purification. With increasing positive experiences from the technology, the economic calculation should improve through a longer depreciation period etc.

RDF gasification has a relatively low investment cost per installed kW compared to other solid-fuel-fired power plants while the electrical efficiency is higher. Along with a low fuel cost, this provides low-cost electricity. However, the technology is in its development stage and the generation cost calculation is based on an availability on par with other waste-fired power plants and Kymijärvi I (>95%). The availability and maintenance cost is therefore somewhat uncertain in this calculation.

All of the semi-commercial technologies except Residual heat-ORC are both electricity and heat producing power sources allowing heat crediting, and therefore the provision of heat has a major impact on electricity generation costs for these technologies.

Sensitivity analysis

The report presents the electricity generation costs' influence from the parameters' cost of capital, depreciation period, investment costs, fuel prices and heat crediting for selected commercial power sources that are significantly affected by each parameter. Below is a summary discussion of these results. You can perform your own sensitivity analyses using the calculation application.

The *cost of capital* which is reasonable for each type of technology varies according to the investment's risk and return requirements of investors. This report has assumed a common cost of capital of 6 and 10%. Technologies that are associated with high investment costs and high risks probably require a higher cost of capital for an investor to make an investment, such as nuclear power for example. For small-scale technologies such as the “solar house” option, a lower cost of capital can probably be applied. The solar photovoltaic type of technology is among the capital-intensive technologies that are most affected by the cost of capital, the cost of electricity generation varies between SEK 0.64 and SEK 1.28/kWh for a cost of capital of 2 and 10% respectively. Onshore wind is least affected by the cost of capital among the capital-intensive technologies where the electricity generation costs vary between SEK 0.40 and SEK 0.65/kWh for a cost of capital of 2 and 10% respectively. For other capital-intensive technologies, the electricity generation costs will increase by about SEK 0.20/kWh when the cost of capital is increased from 6 to 10%.

The electricity generation costs increase exponentially with decreasing *depreciation,* for the capital-intensive power sources in the study there is a clear increase for depreciation periods above 15 years. However, the influence of the depreciation period on the electricity generation costs reduces through an increased depreciation period and for depreciation periods between 25 and 40 years this gives a reduction in the electricity generation costs of about SEK 0.07/kWh for the studied power sources except for solar power which decreases by about SEK 0.13/kWh. The electricity generation costs for onshore wind power, which in the study are calculated using a depreciation period of 20 years, should, according to some in the industry be calculated today using a depreciation period of 25 years with the latest technological and economic developments. However, in this study, the electricity generation costs differ by less than SEK 0.04/kWh between 20 and 25 years in depreciation period, and only just over SEK 0.02/kWh between 25 and 30 years in depreciation period. Increased depreciation periods over 20 years, do not have a lot of effect on the ultimate cost of electricity generation.

Some *investment costs* in the report are associated with major uncertainties, such as for current nuclear and hydroelectric plants. Solar power and offshore wind is most affected by changes to the cost of investment. If the investment cost changes by 20%, the electricity generation costs will change by SEK 0.17 and SEK 0.12/kWh respectively. Other capital-intensive forms of power are affected about the same, if the investment cost changes by 20%, the electricity generation costs change by about SEK 0.08/kWh. The higher the proportion of capital costs, the greater the impact.

For the power sources that are fuel-based, the *fuel prices* have a major impact on the electricity generation cost. Coal condensing is the least affected of those studied, if the coal prices change by 20%, the electricity generation costs change by about SEK 0.04/kWh. Natural gas-fired gas engine and waste-fired co-generation plants are affected most among the studied power sources; a change in the natural gas price of 20% changes the electricity generation costs by gas engine by SEK 0.16/kWh, if the price of waste changes by 20% the electricity generation costs change by less than SEK 0.14/kWh.

In a co-generation power plant, where electricity and heat are generated simultaneously, the co-generated and usable heat must be attributed a value when calculating, i.e. all the costs of generation in the co-generation power plant cannot be attributed to the generation of electricity. This report estimates the cost of electricity generation for co-generation power plants by subtracting the cost of producing district heating from the total generation costs for producing both electricity and heat. *Heat Crediting* affects the electricity generation costs for co-generation significantly, especially for technologies with low electrical efficiency such as Bio-ORC and waste-fired co-generation. If heat crediting increases by 20% this reduces the resulting electricity generation costs of Bio-ORC by about SEK 0.42/kWh, from SEK 1.47 to SEK 1.05/kWh.

Comments

In this 2014 edition of “Electricity from new and future plants” cost estimates for the 14 commercial and 3 semi-commercial power sources have been conducted. For several of the power sources, different plant sizes have been evaluated. In total, 28 different cases have been handled. The selection of power sources and plant sizes has been made in consultation with the project's steering committee and has been principally the same as in previous editions of “Electricity from new and future plants” in 2000, 2003, 2007 and 2011. The changes to plant sizes and power sources that have been made have been justified by technological development etc.

This report compares the cost of generating electricity in power plants with the cost of generating electricity in co-generation plants. For co-generation plants as well as power plants, the entire cost of generation has been allocated to electricity. The district heat generated is then credited for co-generation plants. It is crucial to point out that the main purpose of the co-generation plant is to generate district heating and that possible electricity generation depends on how the heat source for the co-generation plant is spread over the year and if the boiler is the base load or peak load in the district heating system. The size of heat crediting has a great significant for electricity generation costs for co-generation plants, and especially when the alpha value is low, such as for: waste-fired co-generation plants, biomass co-generation with ORC technology and smaller bio-fuelled co-generation plants. For waste-fired plants, in addition to heat crediting, the reception charge also has a great importance on the power generation costs which are the lowest in the report. However, waste plants are not being built to generate electricity in the first hand, but to recover energy from waste and to produce district heating.

Finally, the accuracy of the figures and data presented in this report varies. This is mainly because the experiences from recent investments is unavailable for certain technologies, such as nuclear power and coal condensing power. In addition, there are large differences between the power sources when it comes to the possibility of generalising the preconditions for a typical plant, such as hydroelectric power where the investment cost may vary greatly depending on the geographical conditions. The calculation conditions and results presented are generally specified as integers or with a decimal point, regardless of the number of significant digits or the accuracy contained in the figure. This is to provide clarity and make it easier for the reader to follow the calculations.

The currency used in this report is Swedish krona (SEK, kr). One krona is subdivided into 100 öre. The currency rate in October 2014 was 9,1 SEK per EURO.

Contents

1 Introduction

1.1 Background

The first version of “Electricity from new plants,” was published in 2000. Since then, the report has been updated in 2003, 2007 and 2011. This report represents a revision and update of Electricity from new plants from 2011 [1] and previous reports. The project has been carried out with the following overall targets:

- Provide a comprehensive, relevant and comparable picture of the current status of electricity generation costs for commercially[3] available technologies with a description and account of the factors affecting the electricity generation costs.
- Provide a description of development trends for both commercially available technologies for a number of technologies that may be commercially viable in a decade.
- Create a web-based calculation application for managing and presenting electricity generation costs as well as for sensitivity analyses with respect to the essential factors and pre-conditions.

For commercially available technologies, the best possible technical, economic and environmental data that can be considered as representative of today's national and international markets has been used. Compared to previous editions, a few alterations with regard to technology selection have been made. The technologies and plant sizes covered are shown in Table 1-1.

[3] Commercial technology options referred to in this report are plants that can be procured commercially with warranties.

Table 1-1. Studied commercial technology options.

Technology	Fuel	Electrical output [MW]$_{gross}$	Electrical output [MW]$_{net}$
Condensing power			
Coal condensing	Coal	800	740
Gas turbine	Natural gas	151	150
Gas co-generation condensation	Natural gas	431	420
Nuclear power	Nuclear fuel	1,720	1,600
Co-generation			
Gas co-generation	Natural gas	41	40
Gas co-generation	Natural gas	154	150
Biomass fuel co-generation	Wood chips	5.8	5
Biomass fuel co-generation	Wood chips	11	10
Biomass fuel co-generation	Wood chips	33	30
Biomass fuel co-generation	Wood chips	88	80
Waste-fired co-generation	Unsorted household and industrial waste	23	20
RDF co-generation	Sorted and pretreated waste	23	20
Gas engine	Natural gas	0.1	0.1
Gas engine	Natural gas	1	1
Bio-ORC	Biomass fuel	2.5	2
Sun, wind, hydro			
Wind power, onshore	-	10 (5x2)	-
Wind power, onshore	-	150 (50x3)	-
Wind power, offshore	-	144 (40x3.6)	-
Wind power, offshore	-	600 (100x6)	-
Hydroelectric power	-	5	-
Hydroelectric power	-	90	-
Photovoltaic (roofs for residential dwellings)	-	0.005	-
Photovoltaic (industrial roofs)	-	0.05	-
Photovoltaic (farm)	-	1	-

For the above technology options, electricity generation costs have been calculated both with and without taxes and subsidies. Own comparisons based on input data other than that used and presented in this report can be made by using the calculation application developed in the project and described in Chapter 6. The calculation application calculates and presents electricity generation costs and provides the option of conducting sensitivity analyses with respect to essential factors and preconditions.

For semi-commercial technologies (see Table 1-2), i.e. technologies that can be purchased today but with limited warranties, the electricity generation costs have been calculated in a similar way to commercial technologies. For future technologies (see Table 1-3) the development trends and driving forces, technical development and costs as well as critical components are reported along with a brief assessment of technical performance.

Table 1-2. Studied semi-commercial technologies

Technology	Fuel	Electrical output $[MW]_{gross}$	Electrical output $[MW]_{net}$
Residual heat-ORC	Residual heat	0.8	0.5
RDF Gasification - gas boiler	RDF	56	50
Biomass gasification - gas engine	Wood chips	1.1	1
Biomass gasification - gas engine	Wood chips	5.8	5

Table 1-3. Studied future [4]technologies

Technology	Fuel	Electrical output $[MW]_{gross}$	Electrical output $[MW]_{net}$
Biomass gasification - combined cycle	Wood chips	66	61
Coal condensing with CCS	Coal	800	600
Gas co-generation condensation with CCS	Natural gas	431	360
Wave power	-	10	-

Reference material has mainly consisted of official reports, etc. Construction costs are also based on data from the plant owners and suppliers.

[4] Future technology options referred to in this report are plants that are expected to be commercial within a decade.

1.2 Objectives and target group for the project

The overall objective is to obtain relevant and comparable electricity generation costs for both available and commercially proven technologies and new, less proven technologies.

The results can be used for planning and preliminary feasibility studies. The results have a wide target group:

- A section of the target group includes professional organisations, interest organisations, politicians and government agencies. The results of the report will be used by these target groups as an authoritative description of the technologies and their electricity generation costs.

- Another target group is the power companies. Through the report and project's calculation application they will be able to make estimates of electricity generation costs in a range of studies.

1.3 Scope

The project is limited to the above types of technology and plant sizes. The electricity generation costs for each plant are calculated based on the specific input data per plant and the general preconditions. The costs include complete plants with everything from fuel handling systems to emission control systems, and include internal infrastructure, internal electrical and heating systems and connection to the electricity and district heating grid at the plant's “gate”. Investments outside the plant, for example, infrastructure, electricity and district heating are not included as a rule, except to some extent for wind power. More on what is included in the electricity generation costs is reported in Chapter 3 and for each power source in Chapter 4.

Additionally, no account has been taken of any political factors, such as delays to projects resulting from political decisions, appeals of environmental judgements or detail planning issues. Obviously this is something that could affect a project's schedule and entail costs as a result. The electricity generation costs presented in this report, however, assume that the project proceeds “normally” under its construction.

Finally, the premise of the project has been that all electricity is generated in compliance with today's electrical systems and the changes that might affect today's electrical systems are marginal (i.e. does not account for long-term changes in installed output for different power sources). This means, among other things, that no account has been taken to the potential costs of installing power units that can balance intermittent power sources such as solar and wind power. Which would be relevant in a future electricity system where a larger share of electricity generation came from solar and wind power.

1.4 Abbreviations

The following abbreviations have been used in the report:

AC/DC = alternating/direct current

α value = ratio between electricity and heat production

BFB = Bubbling Fluidized Bed

BIG-CC = Biomass Integrated Gasification Combined Cycle (biomass fuel gasification, gas used for combined cycle gas turbine and steam turbines)

BIG-ICE = Biomass Integrated Gasification Internal Combustion Engine (biomass fuel gasification, gas used for gas engines)

BLFV = Direct contact header(co-generation)

CC = Combined cycle (gas co-generation plant with gas and steam turbine)

CCF = Common Cause Failures (nuclear power)

CCS = Carbon Capture and Storage (including transport)

CFB = Circulating Fluidized Bed

DECC = Department of Energy and Climate Change

O&M = Operation and maintenance costs

EDF = Electricité de France

EIA = U.S. Energy Information Administration

EPC = Engineering Procurement and Construction

EPR = European Pressurized Reactor

EU ETS = EU system for emissions trading

FGD = Flue gas desulphurisation (sulphur removal coal condensing)

FOAK = First-of-a-kind

GWEC = Global Wind Energy Council

HVC = Hot water unit

HTFV = High pressure preheaters (co-generation)

ICE = Internal Combustion Engine

IEA = International Energy Agency

IP number = Investment/production rates (wind power)

IRENA = International Renewable Energy Agency

KVV = Co-generation plant

LCOE = Levelized cost of energy

LHV = Lower heating value

LTFV = Low-pressure preheaters (co-generation)

MV = Feed water tank (co-generation)

NVE = Norwegian Water Resources and Energy Directorate

ORC = Organic Rankine Cycle (Power process with organic working agent)

PV = Photovoltaics (solar cells)

RDF = Refuse derived fuel (fuel based on the sorted waste fractions)

RGK = Flue gas condensation

RT = Recovered wood (sorted waste wood)

SC = Single cycle (only gas turbine)

SCR = Selective Catalytic Reduction (NOx purification technology)

SNCR = Selective Non Catalytic Reduction (NOx purification technology)

SRF = Solid Recovered Fuel (unsorted waste fuel)

STC = Standard Testing Conditions (solar cells)

USC = Ultra supercritical (coal condensing)

VDS = Vestas De-icing System (wind power)

WACC = Weighted Average Cost of Capital

WEC = World Energy Council

WNA = World Nuclear Association

2 Electricity market – an overview

Total electricity generation in Sweden totalled as much as 162 TWh in 2012[5], which is the highest electricity output ever in one year, see Figure 2-1. In 2012, the electricity generated consisted of 48 per cent hydroelectric, 38 per cent nuclear, and 4 per cent wind power. The remaining 10 per cent was combustion-based generation that occurs primarily in co-generation plants and in industry. The largest fuel source used for electricity generation in co-generation plants are biomass fuels which account for 73 per cent. The remaining fuel is natural gas, coal and oil. In the early 1970s, electricity generation consisted of 69 per cent hydroelectric and 20 per cent oil condensing power, however, the total electricity generated was significantly lower then than it is today.

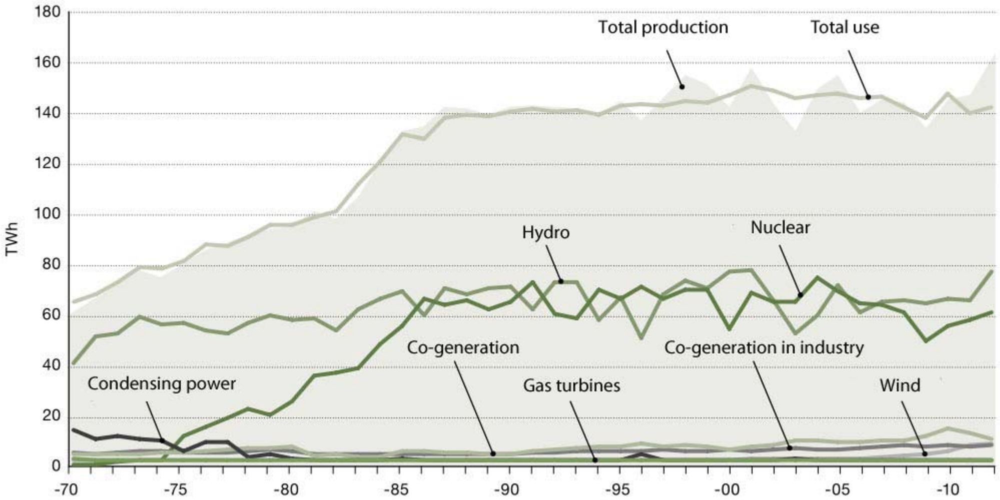

Figure 2-1. Sweden's electricity generation by energy source and total electricity consumption 1970-2012, TWh. Reference: Energy in Sweden 2013 [2].

In December 2012, the total installed electricity generating capacity was 37,353 MW, see Figure 2-2. Hydroelectric power accounted for 43 per cent, nuclear 25 per cent and wind power 10 per cent. Other thermal power accounted of 22 per cent. After the deregulation of the Swedish electricity market in 1996, the installed power generation capacity fell significantly. It was the particularly expensive condensing power that was no longer profitable. After 2000, capacity increased again and is now greater than before deregulation. Wind power accounts for the lion's share of the increase in installed capacity. The capacity also increases with co-generation plants, in industry and by the uprating of nuclear power plants.

[5] Statistics for 2013 were not yet compiled and unavailable for the preparation of this report.

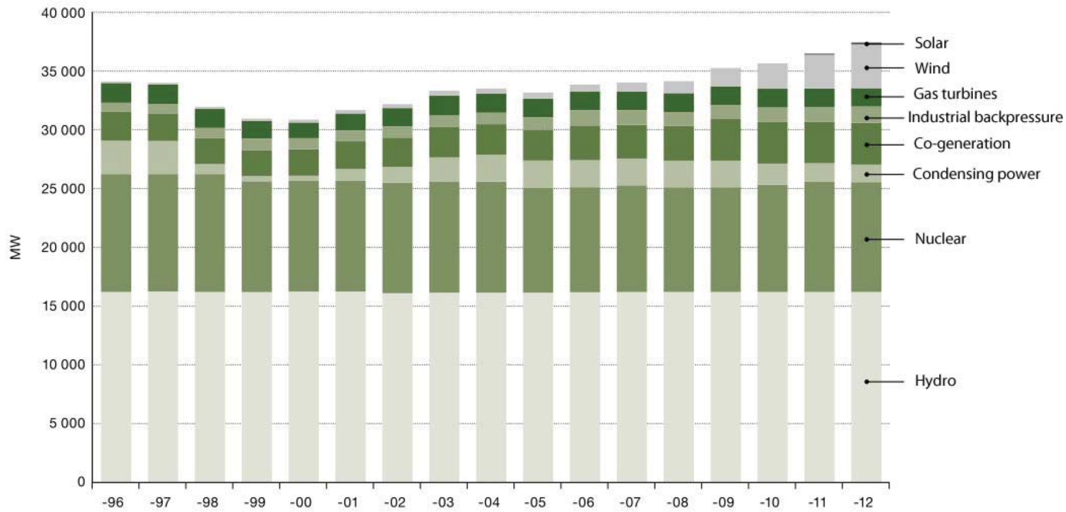

Figure 2-2. Installed electricity generating capacity in Sweden, by energy source 1996-2012, MW. Reference: Energy in Sweden 2013 [2].

There must always be a balance between the generation and the use of electricity in the national electricity system. The Swedish power grid is responsible for maintaining this balance. In addition to preserving this balance, the power grid must also be adapted to accommodate new energy sources that vary over time, such as wind power. Varying power places new demands on flexibility and balance controls. Hydroelectric power is an excellent source for regulating variations and thereby preserving the balance in the power grid. From a national perspective, Sweden has an excellent platform to use hydroelectric power to balance power imbalances that could arise from the use of solar and wind power. With increasing transmission capacity to the rest of Europe, there are increased calls from countries like Denmark and Germany to use Swedish (and Norwegian) hydroelectric power as regulating power. Furthermore, it is important to highlight that the different power sources have different limitations both in terms of installed output and generation. By way of example, the installed output of the co-generation based technologies is limited by the demand for district heating and electricity generation, for example, from solar and wind power is limited by weather conditions.

3 Methodology and general conditions

3.1 General

The electricity generation costs for each plant are calculated based on the specific input data per plant, and the general preconditions are described in this and the subsequent chapter. The calculations are performed using a calculation model developed for the assignment which comes in the form of a web-based calculation application on the Elforsk website (http://www.elforsk.se) where you can make your own comparisons. The calculation application is also described in detail in Chapter 6. Plant specific data such as investment, O&M (operation and maintenance) and the relevant technical data are reported in Chapter 4.

The system limits for the investment costs that are applied are shown in detail by Figure 3-1. The costs include complete plants with everything from fuel handling systems to emission control systems, and include internal infrastructure, internal electrical and heating systems and connection to the electricity and district heating grid at the plant's “gate”. Investments outside the plant, for example, infrastructure, electricity and district heating are not included as a rule, except to some extent for wind power. More on what is included in electricity generation costs is reported in the subsequent chapter in Chapter 3 and for each power source in Chapter 4.

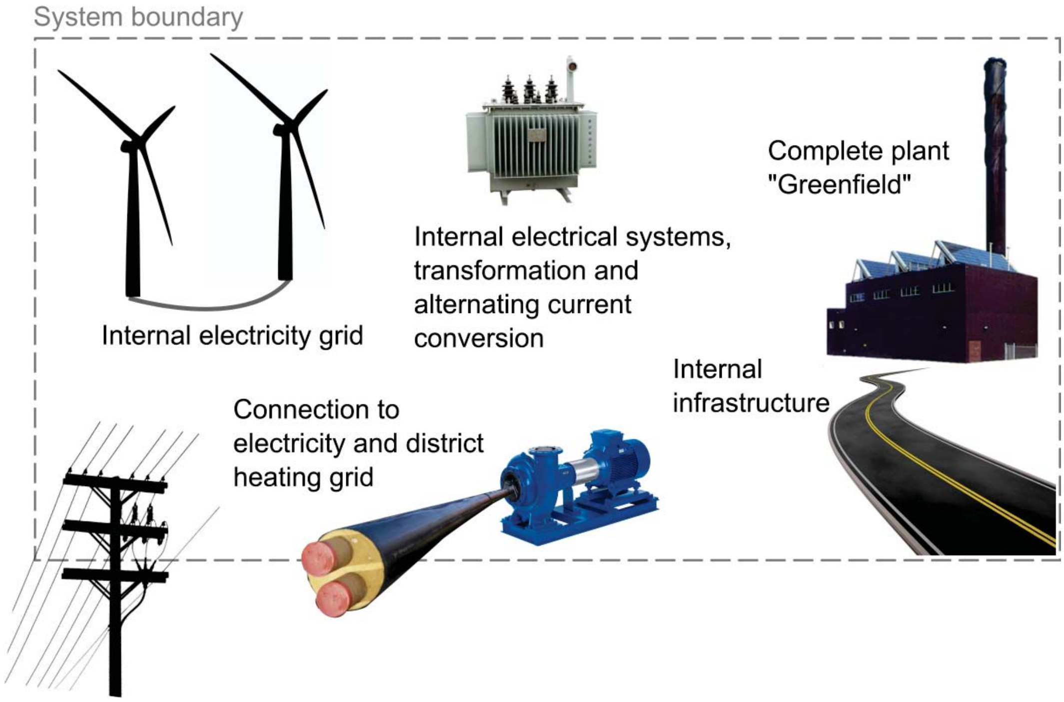

Figure 3-1. Principle figure with system constraints on investment costs.

Generally, all project-specific costs in the estimated electricity generation costs have been included. The following sub-chapters in Chapter 3 deal with the technical and economic aspects of fuel, investment, operation and maintenance, technical specifications, operating conditions, heat crediting, taxes and fees, electricity networks, electricity certificates and economic calculation conditions. Chapter 4 has more detailed conditions for each source of power.

3.2 Fuel

For the calculation of the electricity generation costs presented in this report, the fuel prices and calorific values have been taken from various official sources such as Energy in Sweden 2013 [2], the Swedish Energy Agency's price sheet for peat and biomass fuel for 2013 [3] and the Swedish Energy Agency's Energy Market Report oil, gas, coal [4]. An international survey of negotiated rates can be obtained from energinet.dk [5]. Data is also provided by users and fuel suppliers and a reconciliation has been made in relation to the levels of Elforsk Report 2011:26 [1]. The calorific values given in this report have a lower calorific value for wet fuel. Prices have been estimated as free on site excluding taxes and VAT as per Table 3-1.

Table 3-1. Calorific values and fuel prices in 2014

Fuel	Heating value	Unit	Price	Unit
Biomass fuel (forest residues)	2.6	MWh/tonne	200	SEK/MWh*
Biomass fuel (pellets)	4.7	MWh/tonne	300	SEK/MWh*
Waste	3.1	MWh/tonne	-130	SEK/MWh*
Coal	7.6	MWh/tonne	90	SEK/MWh*
Natural gas ≤ 1 MW_{br}	38.9	MJ/Nm^3	340	SEK/MWh*
Natural gas ≤ 5 MW_{br}	38.9	MJ/Nm^3	320	SEK/MWh*
Natural gas ≤ 150 MW_{br}	38.9	MJ/Nm^3	290	SEK/MWh*
Natural gas > 150 MW_{br}	38.9	MJ/Nm^3	280	SEK/MWh*
RDF	4.2	MWh/tonne	25	SEK/MWh*
Nuclear fuel	-	-	43	$SEK/MWh_{elec,net}$
Residual heat	-	-	0	SEK/MWh

* The calorific value is set as the lower calorific value i.e. LHV.

Biomass fuel prices for forest residues (slash) and pellets were based on Swedish Energy Agency statistics “Wood fuel and peat prices” from 2013 [3] and are estimated to be SEK 200/MWh_{fuel} and SEK 300/MWh_{fuel}.

Waste price of SEK 130/MWh_{fuel} corresponds to a reception fee of SEK 400/tonne gross. The reception fee varies for each municipality and lies between SEK 300/tonne to over SEK 450/tonne [6]. The intention is that this value should represent an average over the country, which means that it can also be deemed to include an average collection cost as this can be incorporated into the fee depending on the organisation and practice. The gross amount means that the fee represents the rate for total weighed waste without deducting the cost of sorting, handling and the disposal of unsuitable fractions. Costs of this type are included in the variable operating and maintenance costs for waste incineration.

Coal price of SEK 90/MWh_{fuel} is based on about EUR 80/tonne, an average price for the period from May 2013 to April 2014, where the price has varied between EUR 74/tonne and EUR 88/tonne according to the Swedish Energy Agency's Energy Market Report oil, gas, coal [4].

Natural gas prices are based on spot prices in 2013 indicated by Dong Energy [7]. The spot price has been relatively stable in 2013 at around EUR 26/MWh, and has been showing a declining trend from the beginning of 2014 at about EUR 20/MWh (April 2014). The average price for 2013 has been used for the cost estimates in this report.

The spot price in Denmark includes a transmission fee at Dragør [5], a network charge (fixed and variable) as determined by the relevant trading companies and an government agency fee of SEK 0.45/MWh_{fuel} [8]. For the individual consumer, natural gas prices vary depending on the annual amount of purchased gas, and this amount is based on a specified operating time and fuel output for each technology, and varies between SEK 280/MWh and SEK 340/MWh (see Table 3-1).

RDF price is dependent on the degree of reprocessing and if the fuel is reprocessed at the plant or on an external site. The fuel costs for RDF usually vary between SEK 0 and 50/$MWh_{fuel.}$ A charge of SEK 25/MWh_{fuel} has been applied in this report.

Nuclear fuel was estimated in June 2013 by the World Nuclear Association (WNA) to cost SEK 43/$Mvh_{elec, net,}$ based on a uranium price of USD 130/kg U_3O_8 and a burnup fraction of 45 MWd/kg [9].

Residual heat has been set to SEK 0/MWh based on the option is that it is dumped.

3.3 Investment costs

The investment cost consists of all the elements of a complete plant, and for all types of plants can in principle it can be divided into:

- Processing equipment and machinery
- Site-bound equipment and service systems, such as fuel handling systems
- Connection to the power grid and for KVV also to district heating networks
- Earthworks and buildings
- Project planning, administration,
- Commissioning

The specific investment cost, expressed in SEK/$kW_{elec,}$ is generally normalised with the plant's net electric output[6] and refers to an "*over-night-cost",* i.e. total investment cost excluding the cost of interest over the construction period. The cost of interest over the construction period, known as the construction expense, is calculated separately based on specific investment costs and a distribution of payment over the construction period which varies between technologies. In the calculation application described in Chapter 6, the construction period can be applied for up to 10 years. The construction period refers to the time from the first major payment until the plant is completed, equipment supplied and commercial operation is in progress. This definition means that the time for licensing, preparatory ground work, procurement, and so on is not taken into account because major capital costs do not normally occur at this time.

[6] For the sun, wind and hydro power sources, the industry practice is to indicate *gross* electrical output, which is why the specific investment cost for these power sources is based on gross electrical output instead.

The investments relating to construction in “standard design” (the system boundary is generally set at the plant gate, see Chapter 3.1), i.e. the specific investment cost does not consider special localisation-related expenses such as:

- Long cooling water channels
- New access roads
- Long electricity/power lines to high voltage networks

For wind power, however, a “standard investment” in infrastructure and power grids is included.

This is an option in the web-based calculation application, described in Chapter 6to specify the location-specific costs for each plant.

To ensure representative investment levels, the compiled information regarding constructed and projected plants in Sweden and the Nordic countries has been used. This refers primarily to plant types that have been implemented in the Nordic countries: biomass fuel and waste-fired co-generation plants, gas co-generation-fired plants and nuclear, wind and solar power plants. Valuable information has also been collected from research reports, national and international professional organisations, international cooperation agencies, annual reports and more. Information has also been collected from suppliers and via the Steering Group's contacts in their own companies and in the networks where research is conducted in this field. Sources for the costs for each type of technology are specified in Chapter 4.

To facilitate the analysis of the information collected, various internationally available indices (”Chemical Engineering Plant Cost Index” (CEPCI) and “Marshall & Swift Equipment Cost Index”) and inflation in Sweden have been compared to the developed costs in this and previous editions [1] [10] [11] [12] for Swedish bio-fired and waste-fired co-generation plant where the cost that has been produced during the investigation in 2000 has been given an index of 100, and a previously developed cost index at Elforsk for hydroelectric power [13].

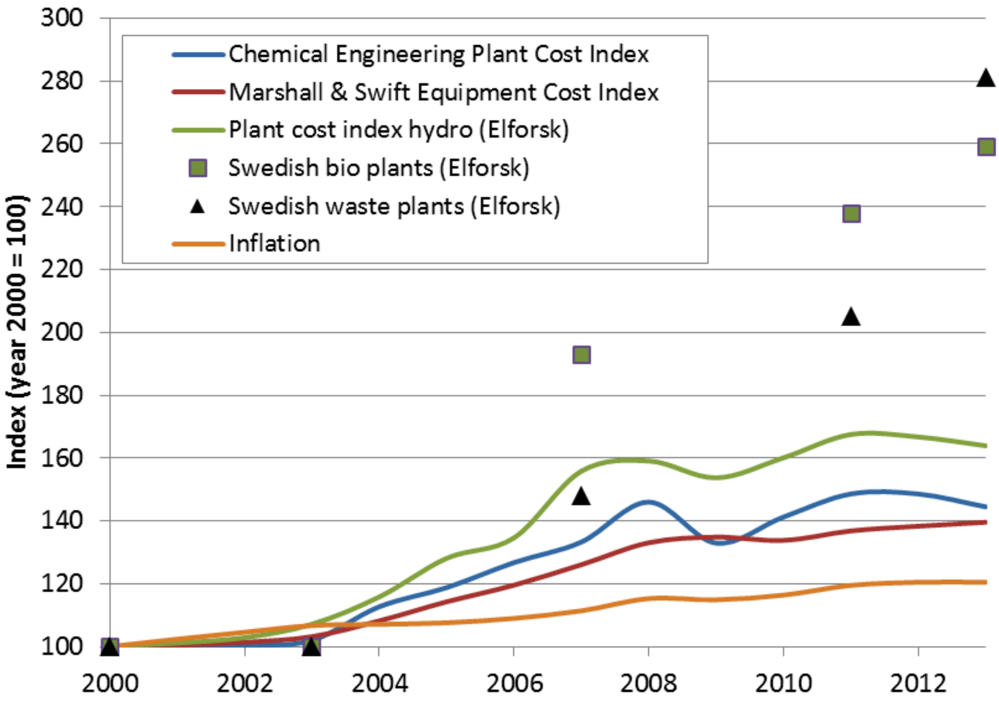

Figure 3-2. Price increases (index) for Swedish biomass fuel and waste-fired co-generation plants and hydroelectric power compared to inflation and two international indices.

The price increases for biomass fuel and waste-fired co-generation plants in the figure can be explained by the market trend with substantial demand pressures and major price increases for steel, for example, (which over the period 2003-2008 was 76.4% according to Statistics Sweden). For biomass fuel-fired plants the price increase that took off in the early 00s could have possibly coincided with the introduction of electricity certificates a few years earlier. Tendering and contract terms are examples of other factors that may be relevant. For biomass fuel-fired plants, a slight reduction in costs from 2011 onwards was indicated which, for example, may have been due to district heating prices that are not expected to increase much more without competitiveness forces in relation to other heat generation methods weakening along with relatively stable steel prices between 2011 and 2014.

3.4 Operation and maintenance (O&M)

Operating and maintenance costs are generally presented as a fixed and a variable component. The fixed part which is expressed as a cost per kW_{elec}, is mainly:

- Staff
- Insurance
- Fixed charges for water and sewage, electricity, etc.

- Fixed maintenance work and spare parts
- Monitoring, cleaning/sanitation and environmental control

The variable part is expressed as a cost per MWh_{fuel} or per MWh $of_{elec.}$ The main items of course vary with the technology. Typical variable O&M costs might include:

- Consumption of water, chemicals and support fuel
- Consumption of sand
- Cost of handling waste products such as ash
- Maintenance performed by staff other than permanent staff

For certain technologies, only a summarised cost for O&M is presented, as either fixed or variable based on estimated normal production, where all the operating and maintenance costs are summarised.

Operating and maintenance costs are based on standard values taken from the literature data, available statistics and/or calculations made based on plant data. Cross checks have been made using data from the operation of specific plants and the project's Steering Group.

Costs for electricity transmission can, after a certain pattern, be considered part of the operating and maintenance costs, although these may vary significantly with the power source. Expenses related to the electricity grid are described in detail in Chapter 3.10.

Plants using solid fuels; waste, biomass fuel and coal have both higher fixed and variable O&M costs compared to plants using a “clean” fuel such as natural gas. The variable O&M costs of the fuel ash content increase in particular, and if chemicals and additives are required for flue gas purification.

O&M costs related to airborne emissions are calculated based on set emissions of NO_x and CO_2.

3.4.1 Ash handling

Biomass-fired plants are able to return the fly ash to the forest which is estimated to cost SEK 700/tonne [14]. Bottom ash is composed largely of sand and can usually be used as filler material at a handling charge of SEK 150-400/tonne. In this study we use SEK 400/tonne. Fly ash from the incineration of waste is classified as hazardous waste and is disposed of in Langøya in Norway at a cost of around SEK 1,000/tonne. Portions of bottom ash from waste incineration (slag) are often used as cover for landfills and are expected to be disposed of at a cost of SEK 50/tonne. The proportion of bottom ash deposited makes this a cost of SEK 560/tonne, which consists both of a landfill tax at SEK 435/tonne, and a processing fee of SEK 150/tonne. The proportion of waste-based bottom ash/slag that can be recycled varies from plant to plant, but is applied in this study at 70%.

3.5 Technical specifications

The technical specifications for the technologies included in the report are based on existing plants or plants under construction. Where technologies are represented in Sweden, Swedish plants are used as the base. For technologies that are not being pursued in Sweden, specifications from international plants have been used, for example, for coal condensing, gas co-generation condensation and new nuclear power plants.

3.6 Operating conditions

The annual electricity generation, i.e. the amount of electricity supplied to the grid, is calculated from the plant's electrical output and operating time. Due to the various industry practices concerning the power sources being calculated or electrical output and operating time being specified in different ways; an explanation of how the calculations are performed follows below.

For the fuel-based power sources, the part of the electricity delivered to the grid is calculated by multiplying the *resulting full-load hours* with a net electricity output[7] for each power source. The *expected full-load hours* refers to the number of equivalent full load hours per year at 100% availability, including a deduction for scheduled stoppages. The *resulting full-load hours* refers to the number of equivalent full load hours in a year including availability, i.e. after deduction of both scheduled and unscheduled stoppages.

$$\begin{gathered} Electricity\ production\ [MWh] = \\ Expected\ full\ load\ hous[h] \cdot Availability\ [\%] \cdot Net\ electricity\ output[MW] = \\ Resulting\ full\ load\ hours\ [h] \cdot Net\ electricity\ output\ [MW] \end{gathered}$$

For solar, wind and hydroelectric power the part of the electricity delivered to the grid is calculated by multiplying the specified gross electricity output[8] with the *resulting full-load hours,* which then include deductions for availability, losses and internal electricity consumption.

$$\begin{gathered} Electricity\ production\ [MWh] = \\ Resulting\ full\ load\ hours\ [h] \cdot Gross\ electricity\ output\ [MW] \end{gathered}$$

The set expectancy and resulting full-load hours are summarised in Table 3-2, all are more fully described for each power source in Chapter 4.

[7] The net electricity output is to represent a resulting average output over the year, less internal losses/consumption and partial load output; as a simplification in the report, the maximum net power output has been used.
[8] The gross electricity output refers to the rated output or generator output for wind and hydroelectric power and peak output for solar power.

Table 3-2. Expected and resulting full-load hours*

Type of technology	Expected full load hours	Resulting full-load hours**	Unit
Coal condensing	8,000	7,760	h/year
Gas turbine	100	98	h/year
Gas co-generation condensation	8,300	8,134	h/year
Nuclear power	8,300	7,885	h/year
Co-generation (bio and gas)	5,000	4,750-4,900	h/year
Co-generation (waste and RDF)	7,500	7,125	h/year
Wind power (onshore)	-	2,900	h/year
Wind power (offshore)	-	3,700	h/year
Hydroelectric power	-	4,000	h/year
Solar power	-	960 – 970	h/year
Residual heat-ORC	8,000	7,600	h/year

* Both expected and resulting full load hours are equivalent full load hours, i.e. operating time for partial load is converted to a total operating time at full load.
** The difference between the expected and the resulting full load hours is availability in the form of unforeseen stoppages.

This is done regardless of whether the demand for electricity varies throughout the year. This means the condensing power plant can be estimated to run as much as is technically possible. It is important to note that this assumption is not necessarily the one that prevails in reality. In an electrical system, power sources with high variable costs are usually forced to the margins by other types of generation with low variable costs. This leads, for example, to gas condensing power plants actually running considerably less than what is technically possible.

Whatever the technologies, a general annual inspection of the power plant is required. How long this period is, and the time of year this occurs, varies with the type of technology; for co-generation plants and also for condensing power plants this occurs over the hottest months when the need for district heating and electricity is lower than during the winter months. However, scheduled maintenance for wind turbines is adapted, as far as possible, to suit the weather conditions.

All the expected full-load hours, availability and resulting full-load hours are presented in more detail for each technology in Chapter 4.

3.6.1 Solar, wind and hydroelectric power

The generation of solar power is controlled by the prevailing solar conditions where the average normal solar incident radiation for Sweden has been used.

Wind turbine power generation is controlled by the wind conditions at the site. For wind power, not only availability losses and internal consumptions but also farm output affects the resulting full-load hours that cover losses incurred due to power plants at a farm influencing each other.

Hydroelectric power is used in Sweden as both base and regulating power depending on the prevailing conditions, where in the watercourse the power plant is located etc. An estimate of the number of full load hours for hydroelectric power has been made by dividing Sweden's total electricity generation over a normal year by the total installed output.

3.6.2 Co-generation

Co-generation is dependent on local demand for district heating and the co-generation-based technologies therefore take into account the provision for heat varying over the year.

Co-generation by burning household and industrial waste is, in addition to the district heating source, also dependent on the fact that the waste cannot be stored for a long time in hot weather. This type of co-generation plant often acts as a base load in a district heating system and therefore is expected to have more than the equivalent full load hours of a co-generation plant.

In the case of co-generation, certain assumptions and simplifications have been made regarding electricity and heat generation in cases where the steam cycle is included:

- The steam output generated is allocated to electricity and heat according to gross alpha[9] and electricity is generated without any losses in the generator
- Technical operating conditions for the high load case are generally assumed for the entire annual generation, i.e. also at intermediate and low load
- Flue gas condensation is assumed in all co-generation cases to provide heat equivalent to 20% of the boiler's thermal power

3.7 Heat crediting

In a co-generation power plant, where electricity and heat are generated simultaneously, the co-generated and usable heat must be attributed a value when calculating, i.e. all the costs of generation in the co-generation power plant cannot be attributed to the generation of electricity. This report estimates the cost of electricity generation for co-generation power plants by subtracting the cost of producing district heating from the total generation costs for producing both electricity and heat visualised in Figure 3-3. This type of heat crediting is called fixed crediting and is described in Chapter 3.7.1. Fixed heat crediting can be applied when, as in this report, it concerns new investment in

[9] Electricity from the generator is divided by the heat from the condenser.

a district heating system, i.e. if a co-generation plant had not been built, a heating plant would have been built instead.

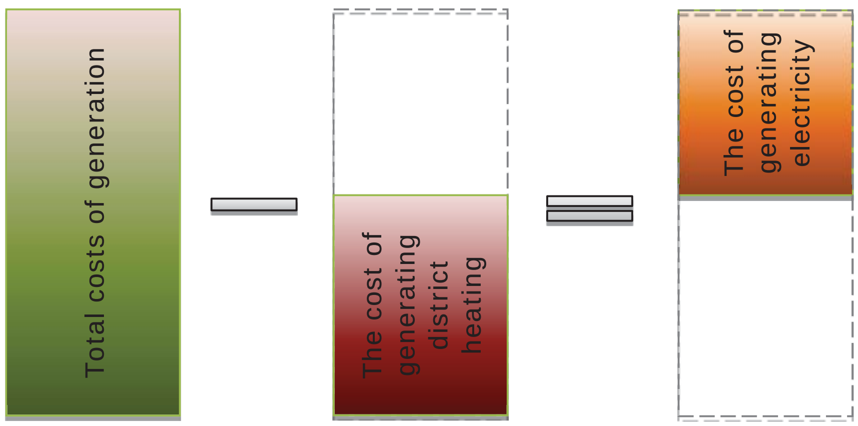

Figure 3-3. Visualisation of the principle for fixed heat crediting

3.7.1 Fixed heat crediting

The cost of producing district heating is calculated based on an alternative investment in a biomass fuel-fired hot water plant with an equivalent heat output as a co-generation plant, along with the fuel, operating and maintenance costs of a hot water plant. The cost of generating heat varies with the size of the hot water plant leading to different heat crediting for different sizes of plant, summarised in Table 3-3.

Table 3-3. Fixed heat crediting for different plant sizes

Technology	Size [MW_{heat}]	Fuel	Heat crediting [SEK/MWh_{heat}]
Small plants	0.1 – 1	Pellets	594
Medium sized plants	1 – 10	Pellets	499
Large plants	>10	Wood chips	324

For plants > 10 MW_{heat} the alternative investment is assumed to be equivalent to a biomass fuel-fired hot water unit of 10 MW_{heat} fitted with flue gas condensation. The specific investment cost is estimated at SEK 6,000/kW_{heat} on the basis of data collected from plant owners with different plant sizes. The fixed O&M cost is estimated at 2% of the investment, variable O&M cost is applied at SEK 18/MWh_{fuel} based on data from Gustavsson et. al [15]. In recent years, no major hot water units have been constructed that are larger than Hässleholm which is a 23 MW_t + 7 MW flue gas condensation plant which makes the calculation difficult for larger plants. However, indications suggest that the specific investment cost does not decrease for sizes above about 10-15 MW_{heat}.

For plants between 1 and 10 MW_{heat}, it is assumed that alternative investment corresponds to a pellet-fired hot water unit of 1 MW_{heat}. Based on data collected from some ten plants of different sizes in Sweden, a specific investment cost is applied at SEK 6,000/kW_{heat}. The fixed O&M costs are applied at SEK 68/kW_{heat} and variable at SEK 15/MWh_{fuel} based on Bergstrom and Johansson [16]. The cost of fuel pellets is set at SEK 300/MWh_{fuel}.

For small plants of 0.1 to 1 MW_{heat}, it is assumed the alternative investment corresponds to a pellet-fired hot water unit of 0.1 MW_{heat}. The specific investment cost is estimated at SEK 10,000/kW_{heat} on the basis of data collected for smaller plants. The fixed O&M cost is estimated at one-fifth of the annual cost of a hot water facility at 1 MW_{heat} (SEK 136/kW_{heat}), the variable O&M cost is estimated to be the same as for the case of 1 MW_{heat} (SEK 68/kW_{heat}). The cost of fuel pellets is set at SEK 300/MWh_{fuel}.

Otherwise, the same calculation assumptions are used to calculate heat generation as for other biomass fuel-fired co-generation plants in the report.

Note that heat crediting as above is a generalisation of reality and the real heat generation costs for the specific case depend on the conditions prevailing in the current district heating grid. Heat crediting has a major impact on electricity generation costs and can be modified in the calculation application for internal analyses.

3.7.2 Variable heat crediting

Variable heat crediting can be applied when a co-generation plant is already part of the district heating network and the plant owner wishes to check the cost of generating more or less electricity, for example, by adjusting flue gas condensation. Variable heat crediting has not been used in the calculations in this investigation, but the effect of it can easily be visualised in the calculation application described in Chapter 6.

3.8 Taxes and fees

This chapter presents all the relevant taxes and fees for 2014 in their basic form. For each type of technology listed in Chapter 4, the resulting cost levels for all taxes and fees are based on electricity generation as öre/kWh.

3.8.1 Energy and carbon dioxide tax

According to the Law on Tax on Energy (1994:1776), energy and carbon dioxide tax is generally applicable to fuel as specified inTable 3-4 below.

Table 3-4. Levels of taxation as specified in Bills 2009/10:41 and 2010/11: 1, adjusted tax rate 01/01/2014

Fuel	Unit	Energy tax	CO2 tax
Oil	SEK/m^3	816	3088
Coal	SEK/tonne	620	2687
Natural gas	SEK/1,000 m^3	902	2313
Biomass fuel	SEK/tonne	-	-
Waste	SEK/tonne	-	-

However there are tax exempt areas. The generation options listed in the report are affected by the following exceptions and apply to plants included in emissions trading;

- Upon consumption for the production of taxable electric power, energy and carbon tax is reduced by 100%[10].
- Upon consumption for the compilation of heat in co-generation, the energy tax by is reduced by 70% and carbon tax by 100%[11].

For the simultaneous generation of heat and taxable electric power in a single process, when the heat released is utilised, the distribution of fuel consumed for the generation of heat, taxable electric power and electric power of the type that is not taxable is made through proportioning according to the relevant method of energy generation[12].

Energy tax and carbon tax on fuel is in principle not paid for the generation of taxable electricity. When using fossil fuels in generation, however, a certain proportion is related to internal electricity consumption and is thereby taxed, see Chapter 3.8.2 - Tax on auxiliary power.

Biomass fuel and waste are not taxed.

3.8.2 Tax on auxiliary power

Under the law on tax on energy, the electric power consumed for the production of electric power is tax-exempt[13]. In contrast, producers and electricity suppliers pay energy and carbon tax on fossil fuels used to produce auxiliary power for the plant.

For the calculation of tax on fossil fuel, plant owners have the option of specifying the actual auxiliary power consumption in generation or the use of standard values; 5% of the given gross electrical output for condensing power plants and 1.5% for co-generation plants and therefore pay tax on fuel that corresponds to these shares of production.

[10] 1994:1776 pursuant to Paragraph 7 in Chapter 6a, Section 1
[11] 1994:1776 pursuant to Paragraph 17a in Chapter 6a, Section 1
[12] 1994: 1776 according Chapter 6a, Section 3b
[13] 1994:1776 pursuant to Chapter 11, Section 2, Paragraph 5

For all the plants in the study, auxiliary power consumption is specified on the basis of existing plants; energy and carbon tax on fossil fuel has been calculated based on this.

3.8.3 Taxes related to nuclear power plants

Output tax is levied for the maximum permitted installed thermal power at nuclear power plants. From 1 January 2008, this amounts to SEK 12,648/MW per month. Deductions are allowed at SEK 415/MW when a reactor has been out of operation for a continuous period of more than 90 calendar days. In the calculations it has been assumed that the plants are operated without any interruptions.

The Financing Act (2006:647) regulates the charges that nuclear power companies pay for the storage of nuclear waste and other contaminated material. In order to finance future costs for spent nuclear fuel there are also individual charges for each nuclear power plant. In addition, the reactor owners pledge collateral to the state - individual for each plant - at a total of SEK 19.3 billion for the year 2012.

The fees for handling residual waste rose in 2012 by 120% from an average of SEK 0.01 to 0.022/kWh_{elec} to apply until 31 December 2014. A proposal for the coming 3-year period that has been submitted by SKB means further increases in charges, partly due to the scheduled operating times being extended for several Swedish reactors, which produces more waste to dispose of [17].

Taxes and fees related to residual waste are included in the calculations for operating and maintenance costs, whereas output tax is handled separately.

3.8.4 Property tax

Property tax is generally set at 0.5% of the assessed value for all types of plant except for hydroelectric power and wind turbines which are taxed at 2.8 and 0.2% respectively of the assessed value.

Property tax partly depends on installed output, power generation and if the plant is entitled to electricity certificates. Property tax on a plant with electricity certificates is higher than for a corresponding plant with no electricity certificates; a co-generation plant of 80 MW and 400 GWh per year is adjusted upwards to the order of SEK 1 million per year, or the equivalent of about SEK 0.003/kWh, spread over 25 years[14] if it is eligible for electricity certificates.

Property tax may vary depending on the power source; for wind power, for example, the land can be taxed separately at a tax rate of 0.5% of the assessed value while the property tax for the turbine itself amounts to 0.2% of the

[14] According to calculations based on the Property Tax Ordinance (1993:1199) and “Swedish Tax Agency's general advice on benchmark statements and the basis for taxation and the valuation of power generation units for 2013 general property taxation” (SKV A 2012:09) [140].

assessed value.

The property tax for hydroelectric power since 2011 has been 2.8% of the assessed value, and in 2013 hydroelectric power was taxed at around 50%, which according to calculations performed by Svensk Energi [18] means that the average property tax went up from the previous SEK 0.055/kWh to about SEK 0.089/kWh.

Svensk Energi [18] has produced average costs for property tax on electricity generation for different technologies as below;

- Hydroelectric power SEK 0.089/kWh
- Wind power SEK 0.004/kWh
- Nuclear power SEK 0.003/kWh
- Other thermal power SEK 0.001 – 0.005/kWh

In the calculation for electricity generation costs in this report, the overall costs for hydroelectric, wind and nuclear power above have been used. Other thermal power has been charged at SEK 0.005/kWh, apart from the co-generation plants entitled to electricity certificates that are charged at SEK 0.007/kWh instead based on the calculations mentioned above.

Solar power

According to the Swedish Tax Agency[15] there is no specific calculation model and no specific benchmark statements regarding property tax for commercial solar power plants today. The few that have been assessed for tax have instead been valued according to the “production cost” method (commonly applied to industrial buildings) where the tax amounts to 0.5% of the assessed value based on age, building category, cost of reacquisition and type of area. The valuation model is currently subjudice and is therefore uncertain in its use.

Work is underway, ahead of the coming general property taxation, to include solar power plants in the “power generation units” category as other power sources. This means that an appropriate benchmark statement is set for the category as well as a calculation method for determining the assessed value.

In this report, the commercial solar power farm of 1 MW is charged with a property tax of SEK 0.005/kWh. This is based on the “production cost” method with an estimated assessed value of 4 hectares of land at SEK 1.2 million, with an estimated annual production of 1.2 GWh.

Smaller, non-commercial, solar power plants are not subject to tax in the current situation and are not burdened with any property taxes. In contrast, any possible adjustments to the tax assessment for the premises on which the photovoltaics are located are being discussed, although an adjustment will

[15] Contact with colleagues at the Swedish Tax Agency, 30/04/2014

happen at the earliest in 2018 for single-family tax assessment or 2019 for apartment buildings/industrial tax assessment.

3.8.5 Sulphur tax

Sulphur tax is paid on coal, peat, natural gas and oil with a sulphur content exceeding 0.05% by weight. The tax is SEK 30/kg for sulphur for the combustion of solid or gaseous fossil fuels and peat. For liquid fuels, tax is paid at SEK 27/m^3 for every tenth weight% of sulphur in the fuel. Waste and biomass fuels are not taxable.

Tax is not imposed if the sulphur content amounts to a maximum of 0.05% by weight. Sulphur levels between 0.05 and 0.2% by weight are rounded to 0.2% by weight.

The report shows that only coal condensing power exceeds 0.05% and is burdened with a sulphur tax of SEK 30/kg sulphur.

3.8.6 Nitrogen oxide charge (NO_x charge)

The purpose of the nitrogen oxide charge is to provide an economic incentive for operators to reduce emissions. The system works so that companies pay a fee based on the amount of nitrogen oxide released over the year. The system's fee income is then refunded to operators in relation to how much energy they generated the same year. The winners in the system are those that generate energy with low emissions. The nitrogen oxide charge is payable for all nitrogen oxide emitting energy generating plants that have an annual useful energy in excess of 25 GWh. In the budget bill 2007/08:1 the charge was increased to the current SEK 50/kg_{NOx} (as NO_2).

Coal and gas co-generation condensation along with all co-generation cases except gas engines and biomass fuel gasification (1 MW), are burdened with a nitrogen oxide charge in the report.

Repayment of nitrogen oxide charges is made in proportion to the amount of produced useful energy (electricity and heat including RGK) and for the year 2012 was SEK 9.05/MWh[16]. With low NO_x emissions, the repayment may exceed receipts which produces a net income. For the calculations presented in this report, repayment has been set to SEK 9.05/MWh.

3.8.7 Emission rights

The EU system for trading emission rights (EU ETS) was initiated in January 2001, and on 1 January 2013 a third trading period began which runs until 2020. All plants involved in the scheme are obliged to monitor their emissions of fossil carbon dioxide and hold emission rights for the corresponding amount.

[16] Final evaluation regarding the 2013 level had not been presented at the time of finalising this report.

Plants covered by the scheme, according to the Environmental Protection Agency [19] are as follows:

- Combustion plants with an installed capacity above 20 MW
- Small combustion plants connected to district heating networks with a total capacity above 20 MW
- Combustion units that are part of an industrial plant
- Co-incineration plants

The revised Emissions Trading Directive 2009/29 EC states that pure biomass fuel plants are not covered by trading systems from 2013. However, Sweden does have an “opt-in” where all plants connected to district heating networks with a capacity of at least 20 MW are included in the trading system irrespective of fuel [20]. This means that biomass fuel-fired co-generation plants must monitor their emissions, even if they do not have any fossil fuel emissions.

Plants that burn household and industrial waste are not included in the EU ETS, unless they are classified as incineration plants. The Environmental Protection Agency[17] says that the vast majority of the plants in Sweden that burn household and industrial waste are considered as co-incineration plants as their main purpose is to extract energy and are therefore covered by the system. Plants tasked with the main purpose of disposing of hazardous waste, for example, are not included in the system.

In 2013, emission rights have been traded in the range of EUR 4-6/tonne of CO_2; and the calculations have therefore used a price of SEK 50/tonne of CO_2. All co-generation plants in the report are assumed to be connected to district heating networks with a capacity greater than 20 MW and are therefore charged with a cost for emission rights.

3.8.8 Waste tax

Tax (waste tax) is payable under the Waste Act (1999:673) for waste that is deposited at a waste treatment plant where hazardous waste or other waste of an amount greater than 50 tonnes per year is ultimately stored (deposited) or is stored for a period longer than three years. According to Act 2005:962 the tax amounts to SEK 435/tonne for residual products sent to landfill.

In this report, tax for the disposal of waste (filter ash, flue gas purification products, bottom ash and slag) is included in the operating and maintenance costs for each type of technology. It is primarily waste and RDF-fired co-generation plants that are affected as waste contains inorganic material that must not be disseminated into nature.

[17] Contact with colleagues at the Environmental Protection Agency, 29/04/2014

3.9 Electricity certificates

The electricity certificate system is a market-based support system that aims to increase the generation of renewable electricity in a cost effective manner. Approved plants that generate electricity from renewable sources or peat receive an electricity certificate from the state for each megawatt-hour (MWh) which they then sell on the open market. The electricity certificate is therefore an extra source of income.

Since 1 January 2012, Sweden and Norway have had a common market for electricity certificates. This means that the trading of electricity certificates can be made across national borders and the market becomes larger with more players.

Electricity generated by the new plants from the following sources entitle electricity certificates for 15 years until the end of 2035, according to the Swedish Energy Agency [21]:

- Biomass fuels, according to ordinance (2011:1480) on electricity certificates
- Geothermal energy
- Solar energy
- Peat in co-generation plants
- Hydroelectric power
    - New plants
    - Resumed operation of previously disused plants that following extensive reconstruction can be considered as new
    - Increased production at existing plants
    - Small-scale hydroelectric power which at the end of April 2003, had a maximum installed output of 1.5 MW
    - Plants that due to official decisions or extensive alterations can no longer ensure long-term profitable production
- Wind power
- Wave energy

According to Svenska Kraftnät [22], the price of electricity certificates has varied according toFigure 3-4 in recent years and over the period April 2013 – April 2014 hovered around SEK 190/MWh on average.

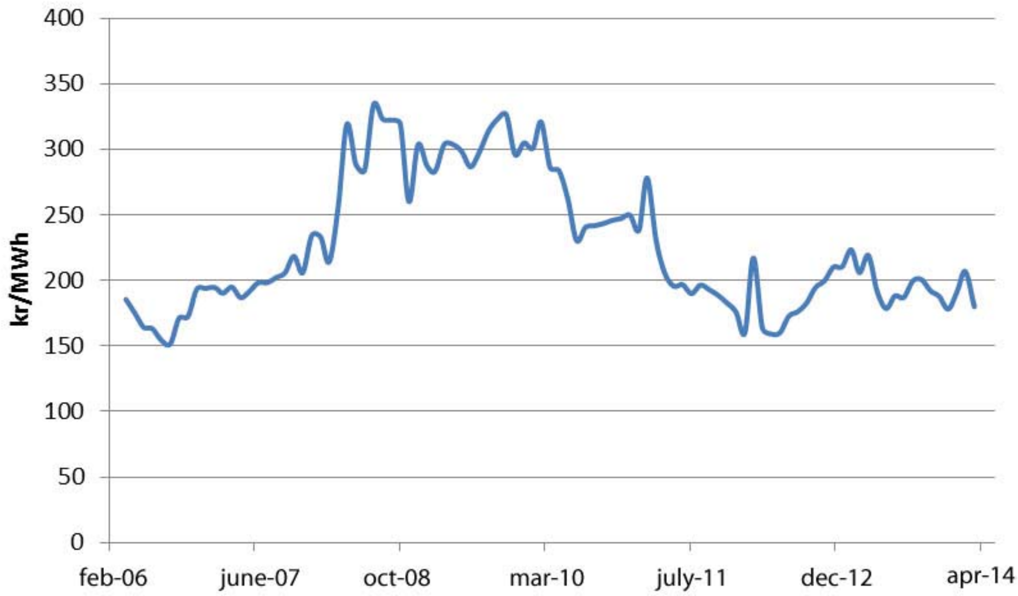

Figure 3-4. Price history for electricity certificates. Source: CESAR, Svenska Kraftnät [22]

3.9.1 Electricity certificates for the calculations

An electricity certificate is income that reduces the need for electricity sales revenue in order to cover the costs of electricity generation. For the calculations, a price of SEK 190/MWh has been used based on the average price last year as above. Payments are made over 15 years with the present value being calculated and is distributed in accordance with the annuity method over the useful lifespan.

Readings from electricity generation for electricity certificates can be made based on gross or net electricity, i.e. including or excluding auxiliary power (own use of electricity in power plants). As a simplification in this edition, it is assumed that the measurement is made based on estimated net electricity generation, which results a decrease in revenue.

3.10 Costs related to the electricity grid

A plant can be connected to the national, regional or local grids depending on the installed output. A larger plant usually needs to connect higher up in the grid hierarchy while a smaller plant can be connected further down. In order to connect a system to a line or a network, the plant owner pays a network tariff for connection to the grid owner to cover the costs associated with connection. As of 01/08/2014, special rules apply when setting network tariffs for connection to renewable electricity generation in certain circumstances[18].

[18] Electricity Act, Chapter 4, Section 9b

All plants connected to an electricity grid must pay a fee (network tariff) to the network owner to transport electricity to the grid. It is about covering costs including energy losses in the network, fees to the upstream network, metering of electricity and the operation and maintenance of all lines, equipment and components. The Energy Market Inspectorate monitors that network companies are complying with the Electricity Act and that the tariffs are reasonable.

The network tariff for electricity transmission varies considerably between electricity networks in Sweden, partly depending on geographic location and where in the network hierarchy they are. At the top of the network hierarchy is the national grid. All networks and plants that are connected to the national grid must pay a fee (backbone network tariff) to Svenska Kraftnät to transport electricity to the national grid. The fee depends on how much the national grid is used, and consists of two main components; a power component to cover the costs of operation, maintenance and utilisation of networks together with an energy component to cover the cost of purchasing electricity for losses in the grid.

As the national grid is at the top of the network hierarchy, the following costs affect all the underlying network owners and affiliated plants. As electricity in Sweden is produced primarily in northern regions and consumed in southern regions, the grid tariff is geographically dependent which is intended to provide long-term control signals. The output tariff for input is highest in the north and falls linearly as you move south, while the opposite applies to output. The energy tariff applies to measured input and output energy and depends on network energy losses at each connecting point, together with an electricity price dependent on the electricity area for additional power losses. For certain access points, the energy tariff can also serve as income if input or output leads to reduced energy losses in the network instead.

Table 3-5 some examples of the national grid tariffs are shown below for different connection points in Sweden, taken from Svenska Kraftnät's price list for the national grid 2014 [23].

Table 3-5. National grid tariff divided into output and energy fees

Connection point	Electricity area	Output tariff, input [SEK/kW]	Energy tariff* [SEK/MWh]
Tornehamn	1	51	22.12
Bräcke	2	39	9.48
Hallstavik	3	32	-6.4
Alvesta	4	25	-16.4

* Positive value means debiting when inputting and crediting when withdrawing, while a negative value means the opposite.

An electricity generating plant of 80 MW_{elec} and with annual electricity generation of 400 GWh, which is connected to the national grid would, based on the table, then be charged with the national grid tariff of SEK 0.032/kWh in Tornehamn and credited with SEK -0011/kWh in Alvesta. In regional and local networks network tariffs vary even more, making it difficult to estimate a fair cost for electricity grids.

The cost of grid connection and the transmission of electricity can be considered part of the investment cost and O&M cost for all power sources in the report as described in Chapters 3.3 and 3.4.

3.10.1 Reduced charge for plants under 1.5 MW

Electricity generation plants with an installed output of <1.5 MW only pay the part of the network tariff equivalent to the annual cost of measurement, calculation and reporting for the grid concession holder's networks and are exempt from grid concession holder costs associated with the operation and maintenance of the electricity grid. Plants with affiliated hedge subscription of less than 63 A and a maximum of 43.5 kW are completely exempt from tariffs for input, provided that the plant consumes more electricity than it generates over the course of a year[19].

3.11 Regulation needs and systemic effects

Different power sources have different characteristics which means that the ability to generate electricity may vary depending on factors such as weather conditions (wind, solar radiation, precipitation), heating surface or maintenance needs. This is usually expressed as the various power sources having different output factors, i.e. varying ability to deliver installed power at a given moment.

The electrical system as a whole must be regulated at every stage in order to meet current electricity consumption. This means that power sources with a high output factor from this aspect have more “value “ than power sources with low output factor, they have a higher “output value”. Practically, this means that the extensive use of power sources with low output factors demand more regulation capacity and spare capacity in the other electrical systems, which may incur additional costs. This has not been evaluated in the calculation of electricity generation costs for the different types of plant in this report.

With the increased share of power sources with low output factors, the electricity market is moving towards a capacity market where the price is set based on available capacity and not just energy production. This is complicated and a deeper analysis on the needs for rules and systemic effects must be conducted, although this falls beyond the scope of this report.

3.12 Financial calculation conditions

Calculation of the electricity generation costs (and, where appropriate, heat) were made with and without taxes, fees and contributions as stated in the annuity method with the following assumptions.

[19] The Electricity Act, Chapter 4, Section 10.

- Real cost of capital 6 %
- Construction interest 4 %
- Economic life
  - General 25 years
  - Small plants 15 years
  - Photovoltaics 25 years
  - Wind power 20 years
  - Nuclear and hydroelectric power 40 years

3.12.1 Cost of capital and construction interest

The actual cost of capital (above 6%) must be equivalent to a “Weighted Average Cost of Capital” (WACC), which reflects a combination of the real rate of return on the plant owner's equity and interest rates on loans.

The real interest rate is therefore dependent on the company or organisation making the investment. The interest rate may be significantly lower, e.g. within municipal operations that can often borrow capital at interest rates lower than other investors, but can also be significantly higher in companies with higher demands on returns. The cost of capital also reflects the risks of a project; the higher the risk the higher the cost of capital used. In reality, a cost of capital of 6% is reasonably low in a high-risk project like building new nuclear power plants, while it is probably too high for investments in photovoltaic systems for residential use. No risk assessment has been made in this report. Chapter 5.3.1 shows a sensitivity analysis of the cost of capital for a number of power sources and the calculation application described in Chapter 6 shows that the interest rate can be adjusted to any level.

A construction interest rate of 4% should not be burdened with a profit requirement and risks in the project, but should be assumed to be interest on loans.

3.12.2 Economic life

The economic life (depreciation period) of the plant not only depends on technical quality and maintenance, but also by factors such as technology development, fuel prices, fiscal impacts, environmental costs etc. With the depreciation periods specified above, however, technical lifetimes that are as reasonable as possible have been taken into account.

For smaller plants, ≤2 MW of$_{elec,\ net,}$ shorter depreciation periods are often justified, including with respect to shorter technical lifetimes of the plant. The calculations for these plants have therefore been based on an economic life of 15 years. Photovoltaics is an exception when suppliers are now providing a power warranty of up to 25 years.

For the calculations, the residual value of the plant is generally assumed to be zero.

3.12.3 Currencies

For conversions from other currencies, the current exchange rates for the respective input data have been used and downloaded from www.valuta.se as the investment was made a few years ago. For real-time rates, an annual average was used in 2013 (Bank of Sweden), giving a rate of SEK 6.5/USD and SEK 8.6/EUR.

4 Electricity generation technologies and generation costs

The technologies included in the study are presented in Table 4-1,Table 4-2 and Table 4-3. The selection of plants and electricity generation capacity has been determined in consultation with the Steering Group for the project. The technologies are classified with respect to their current development status:

1. Commercial technologies - technologies can be purchased with the customary warranties
2. Semi Commercial technologies - technologies are new and can probably be purchased with limited warranties
3. Future technologies - technologies are expected to be commercial by 2025

All of the technologies are covered in separate chapters and includes a presentation of a technology description, development trends, costs, technology-specific conditions in the calculations and the resulting electricity costs for each technology.

Explanation regarding the reporting of electric power
Solar, wind and hydroelectric power
The reported electricity output and specific costs are based on gross electrical output, for wind power and hydroelectric power this is better known as the rated output or generator output and for solar power it is better known as peak output – SEK/kW$_{elec}$, which means SEK per gross electricity output.

Other power sources
The reported electrical output, electric conversion efficiency and specific costs for the remaining power sources, unless otherwise indicated, are based on net electricity generation, i.e. internal electricity consumption in the plant is run from the generated electricity output – SEK/kW$_{elec}$, which means SEK per net electricity output[20].

[20] The net electricity output is to represent a resulting average output over the year, less internal losses/consumption and partial load output; as a simplification in the report, the maximum net power output has been used.

Table 4-1. Commercial technologies

Technology	Fuel	Electrical output [MW]gross	Electrical output [MW]net
Condensing power			
Coal condensing	Coal	800	740
Gas turbine	Natural gas	151	150
Gas co-generation condensation	Natural gas	431	420
Nuclear power	Nuclear fuel	1,720	1,600
Co-generation			
Gas co-generation	Natural gas	41	40
Gas co-generation	Natural gas	154	150
Biomass fuel co-generation	Wood chips	5.8	5
Biomass fuel co-generation	Wood chips	11	10
Biomass fuel co-generation	Wood chips	33	30
Biomass fuel co-generation	Wood chips	88	80
Waste-fired co-generation	Unsorted household and industrial waste	23	20
RDF co-generation	Sorted and pretreated waste	23	20
Gas engine	Natural gas	0.1	0.1
Gas engine	Natural gas	1	1
Bio-ORC	Biomass fuel	2.5	2
Sun, wind, hydro			
Wind power, onshore	-	10 (5x2)	-
Wind power, onshore	-	150 (50x3)	-
Wind power, offshore	-	144 (40x3.6)	-
Wind power, offshore	-	600 (100x6)	-
Hydroelectric power	-	5	-
Hydroelectric power	-	90	-
Photovoltaic (roofs for residential dwellings)	-	0.005	-
Photovoltaic (industrial roofs)	-	0.05	-
Photovoltaic (farm)	-	1	-

Table 4-2. Semi-commercial technologies

Technology	Fuel	Electrical output $[MW]_{gross}$	Electrical output $[MW]_{net}$
Residual heat-ORC	Residual heat	0.8	0.5
RDF Gasification - gas boiler	RDF	56	50
Biomass gasification - gas engine	Wood chips	1.1	1
Biomass gasification - gas engine	Wood chips	5.8	5

Table 4-3. Future technologies

Technology	Fuel	Electrical output $[MW]_{gross}$	Electrical output $[MW]_{net}$
Biomass gasification - combined cycle	Wood chips	66	61
Coal condensing with CCS	Coal	800	600
Gas co-generation condensation with CCS	Natural gas	431	360
Wave power	-	10	-

4.1 Coal condensing power

4.1.1 Technology description

Coal condensing power based on a classical Rankine cycle where coal is burned and the heat from the combustion is used to generate steam. The steam expands in a turbine that produces electricity via a generator. The steam is condensed in a condenser and pumped back to the boiler where the condensed steam is again heated and vaporised. Major coal plants are usually powder-fired while smaller coal plants often consists of fluidized bed boilers.

Plants that are generally built in Europe today are called *Ultra Super Critical* (USC) and have steam parameters of around 280 bar/620°C and an electric conversion efficiency from fuel to net electricity of about 46%. The plants today are being fitted increasingly, if not consistently, with low NO_x burners, SCR, FGD (desulphurisation plant) and dust filtering (electrostatic filter) to reduce environmental impacts.

Carbon capture and storage (CCS)

In recent years, the development of coal-fired condensing power with CO_2 capture and storage, *carbon capture and storage* (CCS), has been taking place around the world. This technology is not commercial and is described as a future technology in Chapter 4.17.

4.1.2 Development trends

The experiences from pulverised coal-fired plants with supercritical steam data are good, and there has therefore been a continued trend towards higher steam data and better performance in recent years. Material and construction development has expanded strongly over recent decades. Today, there are plants with steam data at up to 300 bar/620°C with efficiencies in the range of 47-48%. The desulphurisation method has been developed with efficiencies of above 95%.

For pulverised coal-fired power plants, the target for research is set in relation to a steam temperature of 700 °C and an electric conversion efficiency of 50%. European VGB PowerTech has, with the *COMTES700* project and the ongoing *COMTES+* project, moved one step closer to its goal, through the testing of advanced materials, technologies, and concepts [24].

Coal-fired condensing power plants have recently been built in Europe, partly based on E.ON *Maasvlakte Power Plant 3* in Rotterdam in 2013 at 1,100 MW of turbine output power. The plant has an electric conversion efficiency from fuel to net electricity of 46% with 285 bar/620 °C steam data. The plant has also been prepared for future supplementation with CCS technology.

Several major coal-based projects in Europe, including Vattenfall's coal-fired co-generation plant *Moorburg Power Plant* in Hamburg at 1,654 MW_{elec} which was put into operation in 2014. The plant will have an electric conversion efficiency of 46.5% when only producing electricity and steam data at 276 bar/600 °C.

Development of carbon capture and storage (CCS)
The development of coal condensing power with CCS is described in Chapter 4.17.

4.1.3 Technology-specific calculation conditions

Coal condensing power plants are often planned to run as base load and thereby strive for as many hours at full load as possible. Based on operational experiences in Europe for carbon based base-load plants, the number of expected full-load hours is set to 8,000 hours per year with an availability of 97%.

The electric conversion efficiency is set to 46% to represent today's USC plants described in the technical description in Chapter 4.1.1.

The Environmental Protection Agency [25] reports air emissions from the combustion of various fuels, such as coal. The environmental values used in the calculation are found in the lower part of the range developed by the Environmental Protection Agency.

Calculation conditions for coal condensing power are summarised in Table 4-4.

Table 4-4. Technology-specific calculation requirements for coal condensing power

Parameters	Value	Unit
Type of fuel	Carbon powder	-
Heating value	7.6	$MWh/tonne_{fuel}$
Expected full load hours	8,000	h/year
Availability	97 %	-
Resulting full-load hours	7,760	h/year
Electric output gross	800	MW
Electric output net	740	MW
Electric conversion efficiency*	46 %	-
NO_x emissions	50	mg NO_2/MJ_{fuel}
Sulphur emissions	25	mg S/MJ_{fuel}
CO2 emissions	90.7	g CO_2/MJ_{fuel}

* Electric conversion efficiency is defined as net electricity through fuel.

4.1.4 Costs

Investment costs

There are a number of published studies detailing the costs of new pulverised coal-fired condensing power plants. A selection is presented below with costs expressed in SEK/kW_{elec}, excluding finance costs over the construction period;

- The US *Energy Information Administration* (EIA) estimates the investment cost for a new powder-fired coal power plant of 650 MW_{elec} at the equivalent of SEK 21,400/kW_{elec}, excluding finance costs over the construction period [26].

- *The World Energy Council* (WEC) estimates the investment cost for different ranges of coal power in China (SEK 4,300/kW_{elec}), Australia (SEK 16,500 to 24,400/kW_{elec}), United States (SEK 19,400 to 20,500 /kW_{elec}) and United Kingdom (SEK 15,000 to 18,800 /kW_{elec}) [27].

- Tola and Pettinau [28] compare the costs of various carbon-based technologies, with and without CCS. The investment cost for pulverised coal-fired USC plants is estimated excluding financial expenses over the construction period at between SEK 13,600 to 14,600/kW_{elec} without CCS.

- The UK's *Department of Energy and Climate Change* (DECC) summarised the state of coal power in 2013 in Germany, the Netherlands and Spain [29]. The summary talks about some investment costs, including E.ON's plant *Maasvlakte 3* in Rotterdam at 1,100 MW, which was estimated to be equivalent to SEK 9,300/$kW_{elec.}$ The plant is located adjacent to existing coal plants where much is already in place. The company RWE's *Eemshaven* plant with an output of 1,600 MW_{elec} was estimated in the same summary to the equivalent of SEK 15,400/$kW_{elec.}$ What the costs include is unclear.

The cost varies between studies, mainly depending on the region referred to and the size of the plants. In some studies, it is not known what the costs include. All costs are converted to SEK at the exchange rate prevailing at the time the study was conducted.

Based on the above references, the estimated investment cost for new pulverised coal-fired condensing power in Sweden is SEK 16,000/$kW_{elec.}$ The construction period is assumed to be 3 years and the depreciation period is set to 25 years.

Operating and maintenance costs

Variable O&M costs are applied at SEK 30/MWh_{elec} and fixed O&M costs at SEK 250/kW_{elec} and year based on studies from EIA [26] and WEC [27].

Fuel costs

The price of fuel in the calculations is set at SEK 90/MWh_{fuel} based on the commodity price of about EUR 80/tonne and a heating value of 7.6 MWh/tonne.

Summarised costs

Costs and policy instruments for coal condensing power are summarised in Table 45.

Table 4-5. Summarised costs and policy instruments for coal condensing power

Parameters	Value	Unit
Specific investment	14,800	SEK/$kW_{elec, gross}$
Specific investment	16,000	SEK/$kW_{elec, net}$
Construction period	3	year
Depreciation period	25	year
Fixed O&M	250	SEK/$kW_{elec, net}$
Variable O&M	30	SEK/MWh_{elec}
Fuel price	90	SEK/MWh_{fuel}
NO_x repayment	-0.9	öre/kWh_{elec}
NO_x fees	2.0	öre/kWh_{elec}
Sulphur tax	0.6	öre/kWh_{elec}
Emission rights	3.6	öre/kWh_{elec}
Energy tax	1.3	öre/kWh_{elec}
CO2 tax	5.8	öre/kWh_{elec}
Property tax	0.5	öre/kWh_{elec}

4.1.5 Results

Annual production, costs and the resulting electricity generation cost for coal condensing power are summarised inTable 4-6 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments.

Coal condensing is most subject to taxes and fees of all constituent technologies, both in absolute numbers of less than SEK 0.13/kWh less NO_x repayment and as a percentage of electricity cost of just over 20%.

Table 4-6. Results for coal condensing power with 6% cost of capital

Parameters	Value	Unit
Production		
Electricity generation	5,740	GWh/year
Costs		
Capital cost	17.3	öre/kWh_{elec}
O&M cost	6.2	öre/kWh_{elec}
Fuel cost	19.6	öre/kWh_{elec}
NO_x repayment	-0.9	öre/kWh_{elec}
Taxes & fees	13.7	öre/kWh_{elec}
Results		
Electricity generation cost <u>without</u> policy instruments	43	öre/kWh_{elec}
Electricity generation cost <u>with</u> policy instruments	56	öre/kWh_{elec}

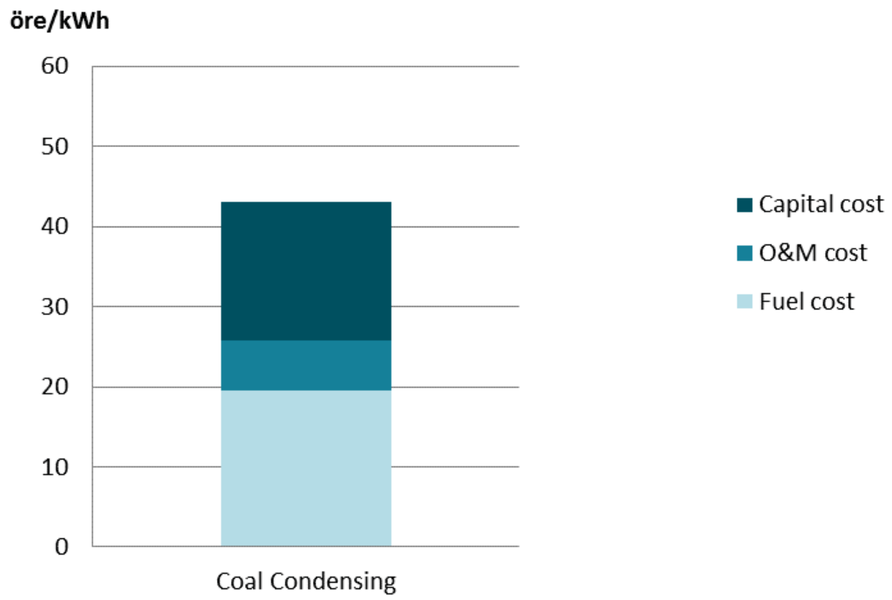

Figure 4-1. Electricity generation costs excluding policy instruments for coal condensing power

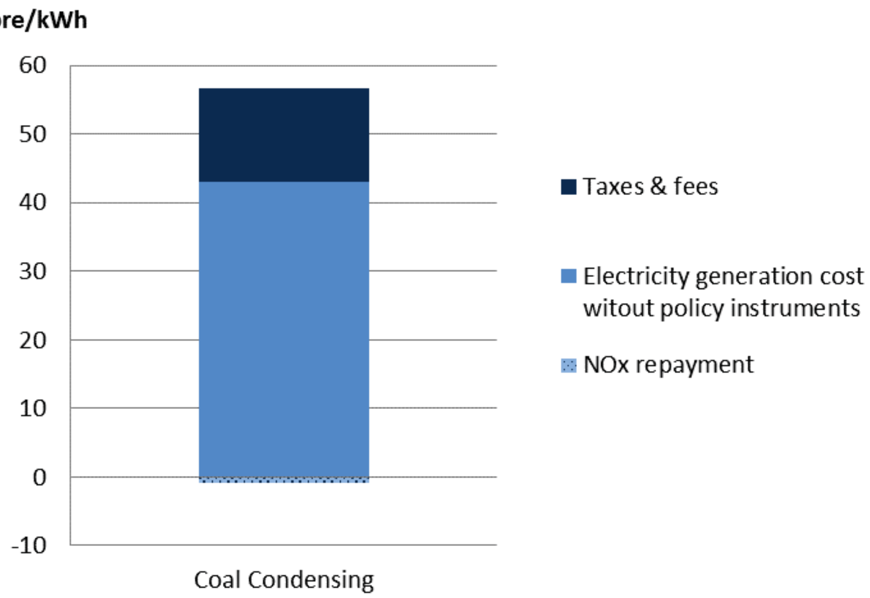

Figure 4-2. Electricity generation costs including policy instruments for coal condensing power

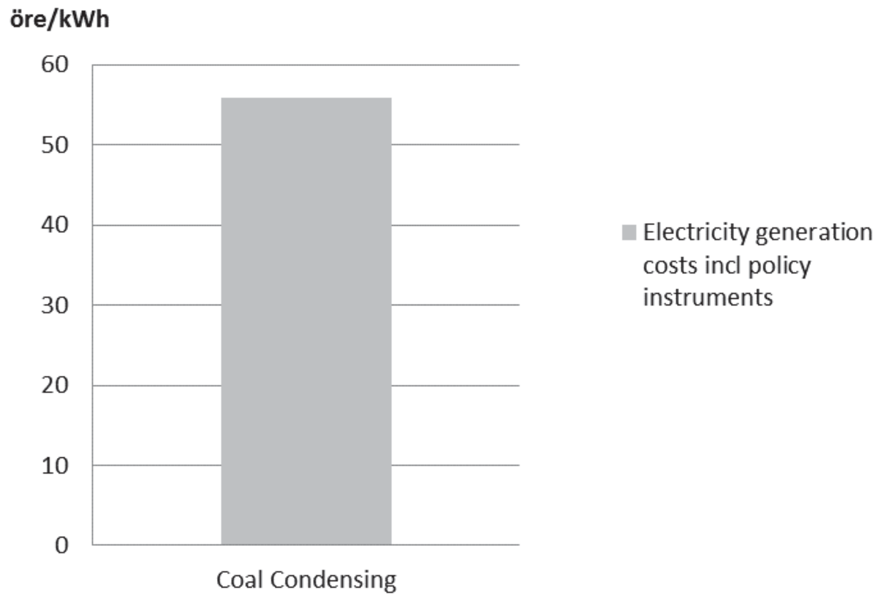

Figure 4-3. Resulting electricity generation costs including policy instruments for coal condensing power

4.2 Gas turbine

4.2.1 Technology description

A gas turbine is an output-based machine that is based on the Brayton cycle with air as the working medium and natural gas as fuel. The Brayton cycle consists of three main stages of work, visualised inFigure 4-4; (1)-(2) compression, (2)-(3) heating through combustion, and (3)-(4) expansion. All three work steps occur within the gas turbine and the design of the parts and its interaction varies greatly between manufacturers, machine sizes and applications. The common denominator is that the gas turbine is a rotating machine that has at least one rotary shaft depending on the design, and that the compressor unit is driven by the turbine section. For electricity generation, the turbine powers a generator to generate electricity. Gas turbines are also used as engines for driving machinery such as aircraft, ships, helicopters and other vehicles.

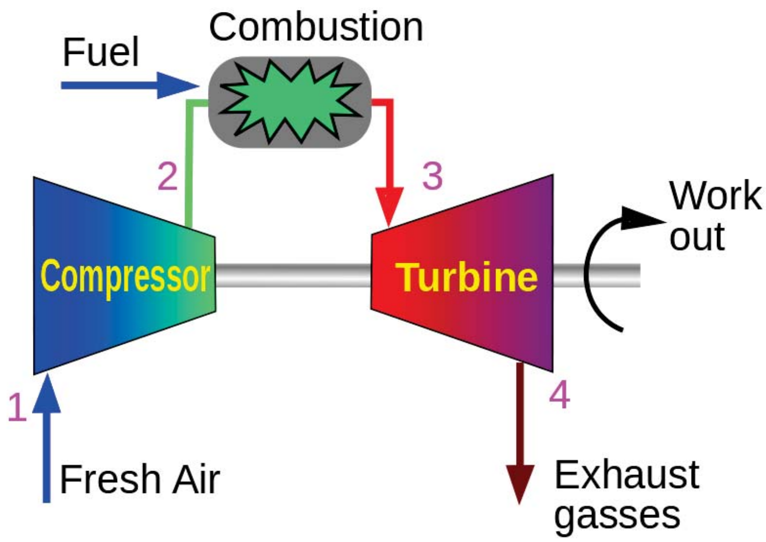

Figure 4-4. Schematic diagram of a gas turbine. Source: Wikipedia [30]

The market for gas turbines in the "mid-size" category (20-60 $M_{elec)}$ is dominated principally by General Electric, Siemens and Rolls-Royce. The three producers together have machines of the order of 30-50 MW_{elec} and efficiencies of around 40% for SC[21] (Single cycle) [31]. Technical performance differs between supplier models, depending on application, such as the Siemens SGT-800 which is outsourced for best use in a combined cycle (CC) focusing on higher exhaust temperatures.

The market for gas turbines of 100 MW covers about a third of the total gas turbine market and is dominated by the suppliers, General Electric, Siemens, Alstom and Mitsubishi. As for gas turbines in the "mid-size" category, electricity efficiencies of > 40% are achieved at SC. An example of a gas turbine of 100 MW is the Siemens SGT5-8000H of 375 MW with an exhaust gas temperature of 625 °C, a pressure ratio of 19.2 and with an electric conversion efficiency of 40% at SC [31]. The high exhaust temperature makes the gas turbine suitable for CC with a steam turbine.

Regulating power

One strength of the gas turbine is its ability to be started quickly and to be able to quickly reach full load, while it has a high power/weight ratio and is therefore space efficient. The fastest SC machine is the General Electric LMS100 that provides 100 MW_{elec} within 10 minutes, with an efficiency of about 45% [31]. This makes it technically well suited as a regulating power.

Finnish Fingrid Oyj, the Finnish equivalent to Svenska Kraftnät, installed a reserve power plant in 2013 in the form of two gas turbines from Italian Ansaldo

[21] SC (single cycle) means that the turbine is self-contained, unlike CC (combined cycle) which is aimed at a gas co-generation plant where the gas turbine is complemented by a steam turbine driven by steam generated from the gas turbine exhaust. Gas co-generation plants are handled in Section 4.3.

Energia at 2x159 MW. The plant is designed to be an output producer and will normally only run for 10-20 hours per year to manage the network disruption. The plant, which is located in Finnish Forssa, can be started remotely from Fingrid's main station in Helsinki in less than 15 minutes [32], [33].

4.2.2 Development trends

Genrup and Thern [31] describe that a new, larger market is expected to open up for gas turbines as regulating power providers to supplement the increasing share of intermittent generation in the form of solar and wind power. At the same time, demands for flexibility are increasing, both in terms of operation and fuel. Requirements for faster start-ups and ramping will mean, for example, that the proportion of steam-cooled gas turbines will decrease over time and be replaced by faster air-cooled gas turbines.

A quest for higher efficiencies will force manufacturers to move towards higher pressure ratios, an increased number of steps and potentially longer rotors; a three-step turbine will likely be replaced with four steps. There is potential to increase efficiency with a fourth step, partly by decreasing the step load [31].

The use of shale gas and bio-gas is expected to increase in the future. The market is therefore demanding better fuel flexibility which will drive more advanced burners and more flexible fuel systems. Biomass fuels can also be corrosive and force manufacturers to develop better high temperature materials with better resistance to oxidation and corrosion [31].

4.2.3 Technology-specific calculation conditions

Gas turbines consisting of a SC gas turbine of 150 MW_{elec} in this report are intended to represent an output producer, the expected full load time is therefore applied at 100 hours per year. The availability of gas turbines is high and set to 98%.

The electric conversion efficiency for a SC gas turbine plant varies between manufacturers and here is set to 40% to represent a plant in the middle of the field with the focus solely on electricity generation such as SC.

Environmental values for gas turbines are collected from Göteborg Energi [34] and Swedegas [35].

Calculation conditions for gas turbines are summarised in Table 4-7.

Table 4-7. Technology-specific calculation requirements for gas turbines

Parameters	Value	Unit
Type of fuel	Natural gas	-
Heating value	38.9	MJ/Nm^3
Expected full load hours	100	h/year
Availability	98 %	-
Resulting full-load hours	98	h/year
Electric output gross	151	MW
Electric output net	150	MW
Electric conversion efficiency*	40 %	-
NO_x emissions	20	mg NO_2/MJ_{fuel}
Sulphur emissions	0	mg S/MJ_{fuel}
CO2 emissions	56.8	g CO_2/MJ_{fuel}

* Electric conversion efficiency is defined as net electricity through fuel.

4.2.4 Costs

Investment costs

Published investments, and several studies prepared by EIA, Elforsk and NVE ([26], [31] and [36]), which have compiled the costs for gas turbines are summarised in Figure 4-5. EIA [26] clearly shows how the total investment cost is divided into cost items for two different output sizes and technologies; corresponding distribution has been used to calculate the cost of Genrup and Thern [31] to represent the total cost. Finnish Fingrid Oyj invested in a reserve capacity of 2x159 MW equivalent of SEK 3,100/kW_{elec} in 2013 and can be seen in the graph [32]. Based on the graph, the specific investment cost is set for a SC gas turbine plant with a net electrical output of 150 MW at SEK 4,600/kW_{elec}.

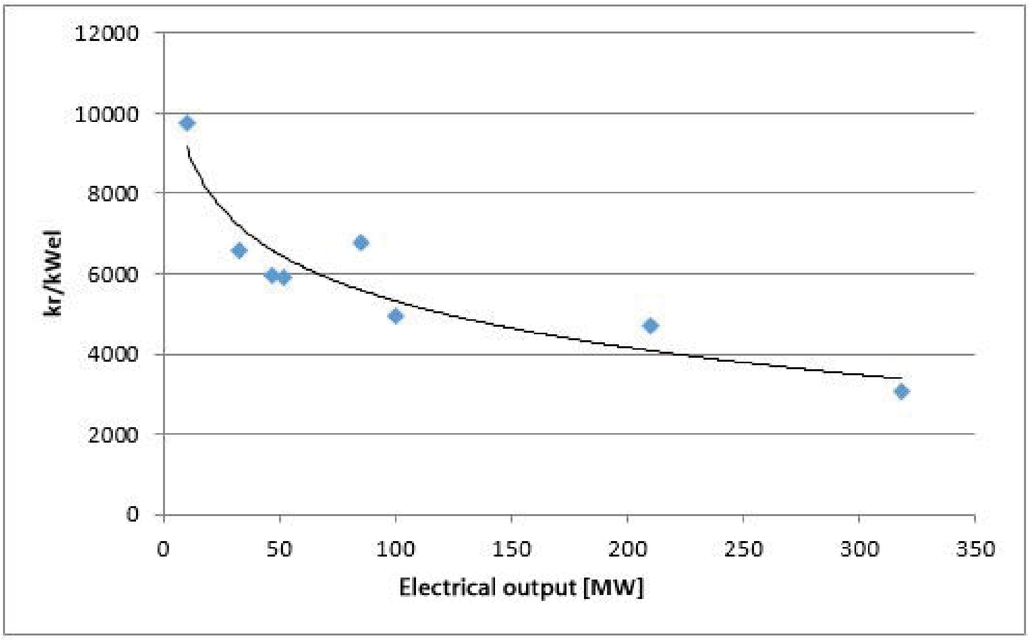

Figure 4-5. Specific investment costs for SC gas turbine based on gross electrical output.

The construction period is set to 2 years with a depreciation period of 25 years, in accordance with Genrup and Thern [31].

Operating and maintenance costs

Operating and maintenance costs for SC turbines are generally divided into a fixed and a variable component. The variable component is exclusively a service agreement with the supplier. A plant that runs approximately 5,000 hours annually has a variable component of approximately SEK 30/MWh$_{elec}$ [31] and a fixed component of approximately SEK 65/kW$_{elec}$ ([26], [36]), corresponding to over SEK 30 million/year.

A plant that produces regulating power at about 100 hours per year has less staffing needs and other agreements where maintenance is based on the time interval ahead of the operating time interval. An estimate is made at approximately SEK 7.5 million/year, corresponding to approximately SEK 50/kW$_{elec,}$ based on data from plant owners with relevant reserve power plants.

Fuel costs

The price of natural gas is detailed in Chapter 3.2 and for a plant of 150 MW has been set at SEK 280/MWh$_{fuel.}$

Summarised costs

Costs and policy instruments for gas turbines are summarised in Table 4-8.

Table 4-8. Summarised costs for gas turbines

Parameters	Value	Unit
Specific investment	4,570	SEK/kW$_{elec, gross}$
Specific investment	4,600	SEK/kW$_{elec, net}$
Construction period	2	year
Depreciation period	25	year
O&M	50	SEK/kW$_{elec, net}$
Fuel price	280	SEK/MWh$_{fuel}$
NO_x repayment*	0	öre/kWh$_{elec}$
NO_x fees*	0	öre/kWh$_{elec}$
Sulphur tax	0	öre/kWh$_{elec}$
Emission rights	2.6	öre/kWh$_{elec}$
Energy tax	0.1	öre/kWh$_{elec}$
CO2 tax	0.2	öre/kWh$_{elec}$
Property tax	0.5	öre/kWh$_{elec}$

* Combustion plants with electricity and/or heat <25 GWh are not covered by the nitrogen oxide charge.

4.2.5 Results

Annual production, costs and the resulting electricity generation cost for gas turbines are summarised inTable 4-9 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments.

It is worth reflecting that the gas turbine in the report has a low scheduled operating time in order to represent an output producer and not an energy producer, which leads to very high electricity costs; flexibility, availability and high output over a short time are valued higher than low production costs. If as many expected full-load hours for gas co-generation power are applied (8,300 hours per year), and with the corresponding O&M costs, the cost of electricity will be SEK 80/kWh$_{elec}$ including all policy instruments. However, it is unlikely that a SC gas turbine would run as base load when the efficiency is so much higher and electricity costs are significantly lower for a gas co-generation plant.

The high cost of power generation for gas turbines as a power producer varies considerably depending on how much the plant is running and comparing with other power sources is considered of no interest, which means the resulting electricity generation cost is only presented in Chapter 4.

Table 4-9. Results for gas turbines with 6% cost of capital

Parameters	Value	Unit
Production		
Electricity generation	14.7	GWh/year
Costs		
Capital cost	382.0	öre/kWh$_{elec}$
O&M cost	51.0	öre/kWh$_{elec}$
Fuel cost	70.0	öre/kWh$_{elec}$
NO_x repayment*	0	öre/kWh$_{elec}$
Taxes & fees	3.4	öre/kWh$_{elec}$
Results		
Electricity generation cost without policy instruments	503	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	506	öre/kWh$_{elec}$

* Combustion plants with electricity and/or heat <25 GWh are not covered by the nitrogen oxide charge

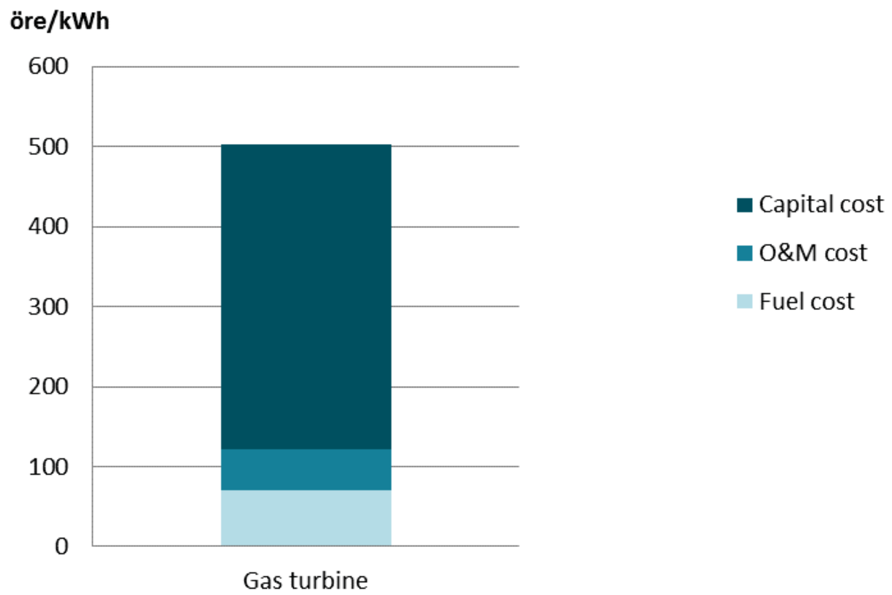

Figure 4-6. Electricity generation costs excluding policy instruments for gas turbines

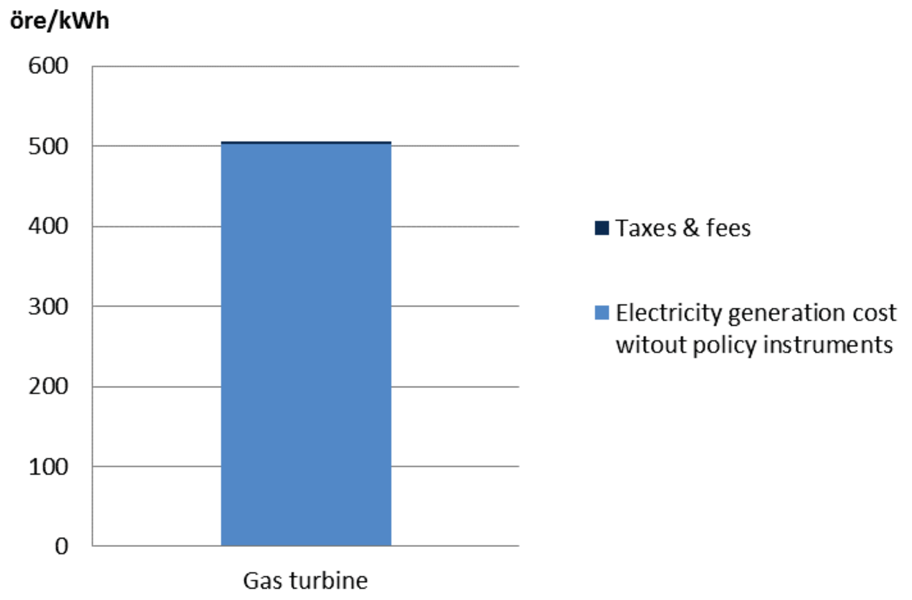

Figure 4-7. Electricity generation costs including policy instruments for gas turbines

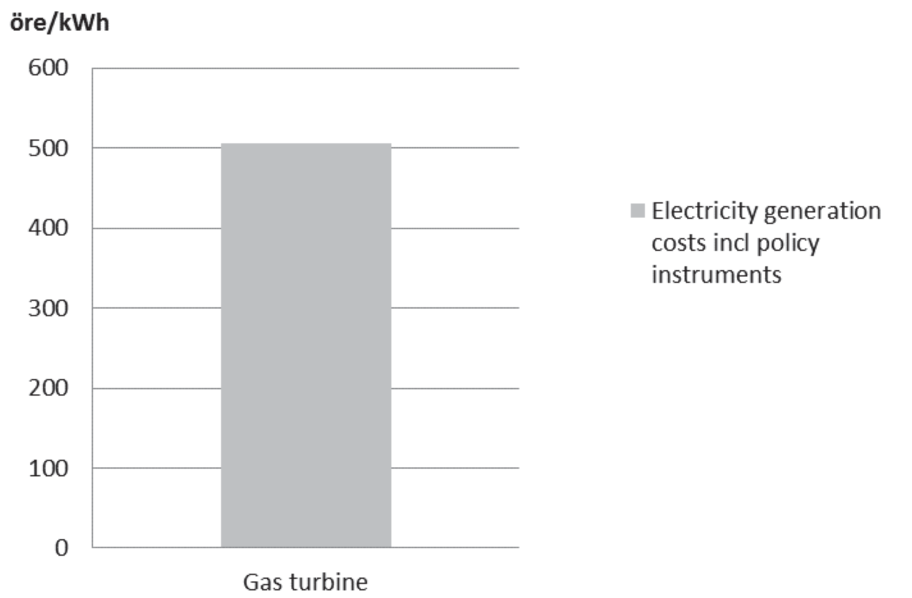

Figure 4-8. Resulting electricity generation costs including policy instruments for gas turbines

4.3 Gas co-generation power

4.3.1 Technology description

A gas turbine power plant consisting of a combination of a gas turbine and a steam turbine. Gas turbines are described in more detail in Chapter 4.2.

The gas turbine's hot exhaust gas (~ 500 °C) is used in an exhaust boiler to heat the steam in a classical Rankine cycle which is then expanded in a steam turbine, as illustrated in Figure 4-9. Electricity is generated through a generator from both the gas turbine and the steam turbine.

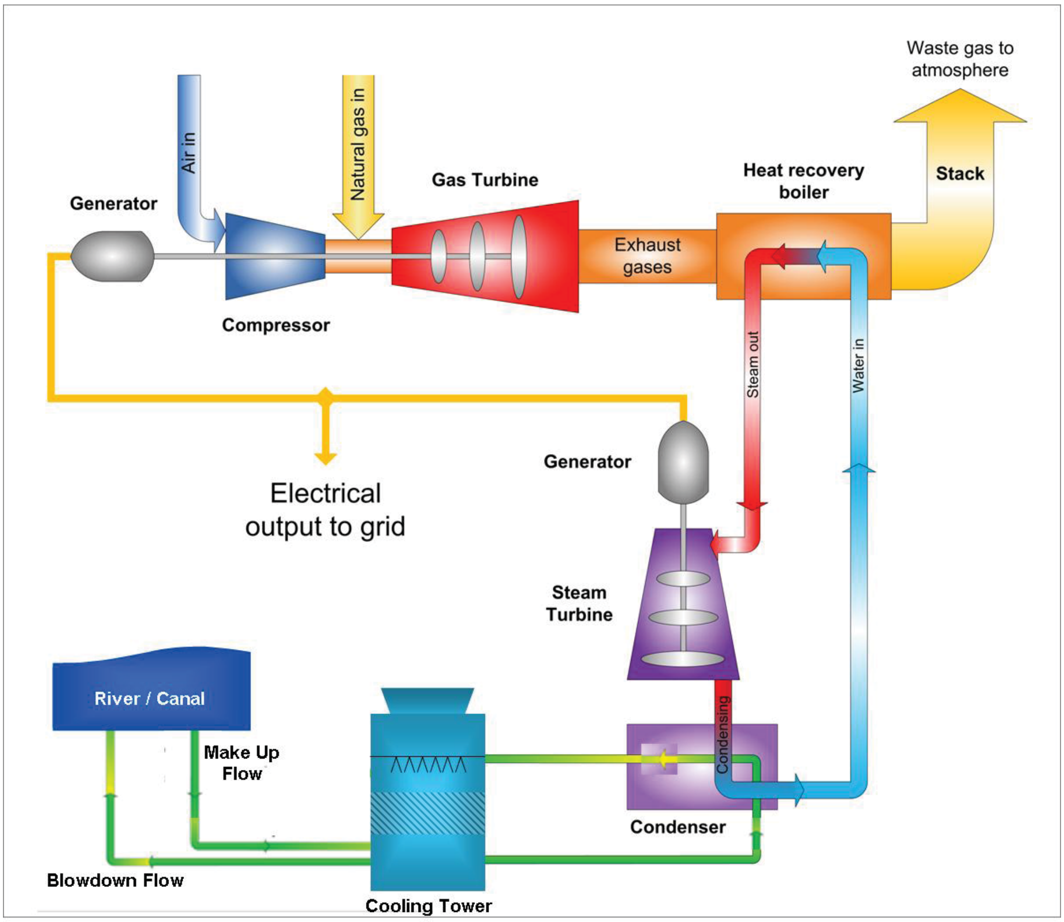

Figure 4-9. Schematic diagram of a gas co-generation cycle. Source: Knottingley Power [37]

Unlike a SC[22] (Single Cycle) the gas turbine and its exhaust temperature are optimised to power a steam cycle with very best possible overall performance for the whole plant. The electric conversion efficiency is lower for the gas turbine at the CC due to the requirement for high exhaust temperature, but the overall

[22] SC (single cycle) means that the turbine is self-contained, unlike CC (combined cycle) which is aimed at a gas co-generation plant where the gas turbine is complemented by a steam turbine driven by the exhaust generated from the gas turbine.

electric conversion efficiency of the entire gas co-generation plant reaches levels of around 60%. E.ON's gas co-generation plant *Ulrich Hartmann* in Irsching in southern Germany, with its Siemens SGT5-8000H is certified for an electric conversion efficiency of 60.75% [31].

Gas co-generation plants are usually built from 50 MW_{elec} and reach the highest electricity efficiencies of all currently commercial plants. This is necessary as they use a high quality and relatively expensive fuel [31].

Gas co-generation plants are complex systems with sometimes several gas turbines connected to a steam turbine and several intermediate superheaters in the steam cycle. Speed and flexibility are lower in a gas co-generation compared to a SC gas turbine due to the increased complexity.

Carbon capture and storage (CCS)
In recent years, the development of gas co-generation condensation with CO_2 capture and storage, *carbon capture and storage* (CCS), has occurred around the world. This technology is not commercial and is described as a future technology in Chapter 4.18.

4.3.2 Development trends

Genrup and Thern [31] summarise the development of gas turbines and gas co-generation plants, and over the past three years, both efficiency and flexibility have improved considerably. All the major manufacturers now offer gas co-generation plants with efficiencies up to 61%.

The efficiency of gas co-generation plant can be increased through various measures of which the most important is to raise the temperature for the gas turbine's combustion chamber and into the first turbine stage. A likely trend for gas co-generation plants going forward is that the temperature of the gas turbine combustors will increase to 1,600 °C and consequently the admission temperature will rise in the exhaust gas boiler to temperatures above 600 °C [31]. This places greater demands on both high-temperature materials and cooling technology. However, advanced high temperature materials in, for example, turbine blades, are costly. Both Siemens H-Class and Mitsubishi F-Class have reverted from turbine blades in single crystal to directionally solidified blades. Provided you have the correct cooling technology, these plants generate electricity at a significantly lower cost [31].

In addition to the increase of the inlet temperature to the turbine, there is a constant development process for individual components. The intention is to ensure low pressure drops, low emissions of NO_x, a low proportion of unburned hydrocarbons and a uniform temperature profile in the working fluid before expansion takes place in the turbine.

It is unlikely that the efficiency will be increased significantly above 60% in the near future. It is rather a case of, while maintaining efficiency, increasing availability and enhancing both operational and fuel flexibility to meet market demand. In line with the growing proportion of intermittent electricity generation, it is more important to maintain a high electric conversion efficiency even at partial load [31].

Development of carbon capture and storage (CCS)
To reduce the environmental impact of natural gas co-generation plants, the focus today is on CCS. The development of gas co-generation plants with CCS is described in Chapter 4.18.

4.3.3 Technology-specific calculation conditions

Gas and condensing power totalling 420 MW_{elec} is supposed to be run as a base load with as many expected full-load hours as possible. The expected full load hours are set at 8,300 hours per year of the total revision time over the lifetime for gas co-generation plants according to General Electric is very short, at only 12 days for GE LM6000 at 50,000 operating hours [38]. The availability of gas turbines is high and is set to 98%.

The electric conversion efficiency for a gas co-generation condensation varies between manufacturers and here is set to 58 % to represent a plant in the middle of the field.
Environmental values for gas turbines are collected from Göteborg Energi [34] and Swedegas [35]. A plant of this size is assumed to have SCR in order to reduce the emissions of nitrogen oxides.

Calculation conditions for gas and condensing power are summarised in Table 4-10.

Table 4-10. Technology-specific calculation requirements for gas co-generation condensation power

Parameters	Value	Unit
Type of fuel	Natural gas	-
Heating value	38.9	MJ/Nm^3
Expected full load hours	8,300	h/year
Availability	98 %	-
Resulting full-load hours	8,134	h/year
Electric output gross	431	MW
Electric output net	420	MW
Electric conversion efficiency*	58 %	-
NO_x emissions	10	mg NO_2/MJ_{fuel}
Sulphur emissions	0	mg S/MJ_{fuel}
CO2 emissions	56.8	g CO_2/MJ_{fuel}

* Electric conversion efficiency is defined as net electricity through fuel.

4.3.4 Costs

Investment costs
The investment cost is developed in a similar way to SC gas condensation; several studies with aggregated costs as well as individual publically announced investments in Europe form the basis for Figure 4-10. Studies developed by EIA, Elforsk and NVE form the basis for the digram ([26], [31] and NVE [36]). EIA [26] clearly shows how the total investment cost is divided into cost items for two different power sizes and technologies; corresponding distribution has been used to calculate the cost of Genrup and Thern [31] to represent the total cost. Based on the graph, the specific investment cost is set for a gas co-generation condensation plant with a net electrical output of 420 MW at SEK 7,000/kW_{elec}.

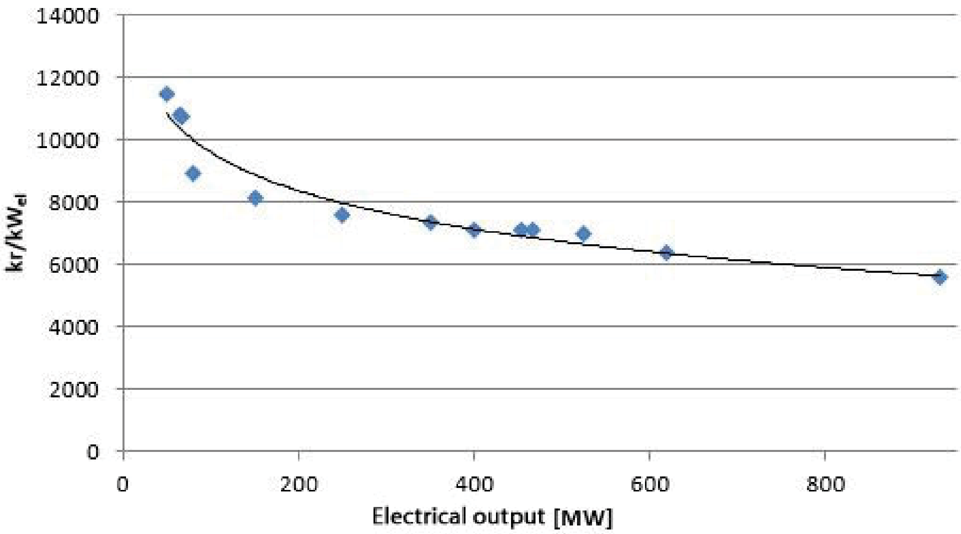

Figure 4-10. Specific investment cost for gas co-generation condensation, based on gross electrical output.

The construction period is set to 3 years with a depreciation period of 25 years, in accordance with Genrup and Thern [31].

Operating and maintenance costs
Operating and maintenance costs for gas co-generation condensation plants are generally divided into a fixed and a variable component. The variable component is exclusively a service agreement with the supplier and applied to SEK 25/MWh_{elec} [31]. The fixed component is applied at SEK 80/kW_{elec} ([26], [36]).

Fuel costs
The price of natural gas is detailed in Chapter 3.2 and for a plant of 420 MW has been set at SEK 280/MWh_{fuel}.

Summarised costs
Costs and policy instruments for gas and condensing power are summarised in Table 4-11.

Table 4-11. Summarised costs and policy instruments for gas and condensing power

Parameters	Value	Unit
Specific investment	6,820	$SEK/kW_{elec,\ gross}$
Specific investment	7,000	$SEK/kW_{elec,\ net}$
Construction period	3	year
Depreciation period	25	year
Fixed O&M	80	$SEK/kW_{elec,\ net}$
Variable O&M	25	SEK/MWh_{elec}
Fuel price	280	SEK/MWh_{fuel}
NO_x repayment	-0.9	öre/kWh_{elec}
NO_x fees	0.3	öre/kWh_{elec}
Sulphur tax	0	öre/kWh_{elec}
Emission rights	1.8	öre/kWh_{elec}
Energy tax	0.4	öre/kWh_{elec}
CO2 tax	0.9	öre/kWh_{elec}
Property tax	0.5	öre/kWh_{elec}

4.3.5 Results

Annual production, costs and the resulting electricity generation cost for gas co-generation condensing power are summarised in Table 4-12 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments. By far the most significant cost item for gas and condensing power is the fuel cost, which represents 78% of electricity generation costs including policy instruments.

Table 4-12. Results for gas and condensing power with 6 % cost of capital

Parameters	Value	Unit
Production		
Electricity generation	3,416	GWh/year
Costs		
Capital cost	7.1	öre/kWh_{elec}
O&M cost	3.5	öre/kWh_{elec}
Fuel cost	48.3	öre/kWh_{elec}
NO_x repayment	-0.9	öre/kWh_{elec}
Taxes & fees	3.9	öre/kWh_{elec}
Results		
Electricity generation cost without policy instruments	59	öre/kWh_{elec}
Electricity generation cost with policy instruments	62	öre/kWh_{elec}

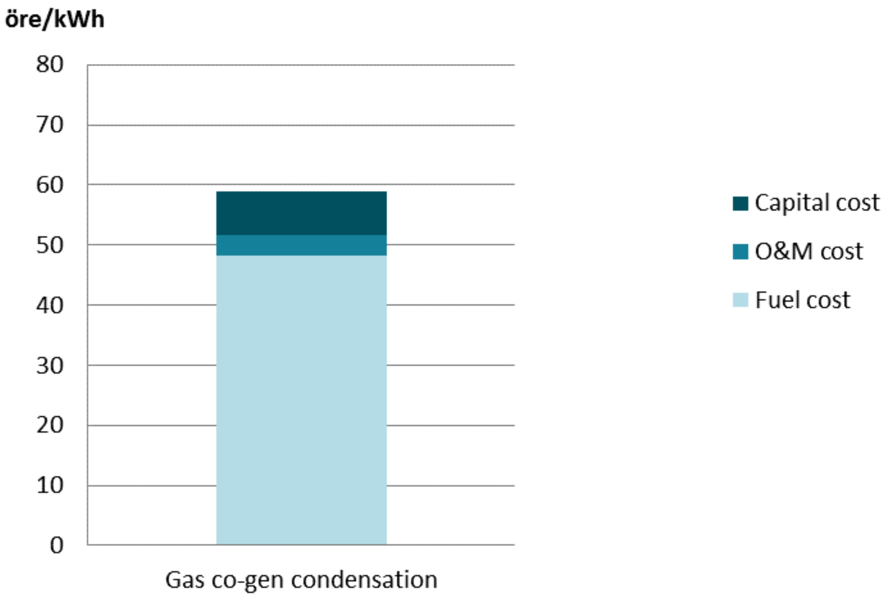

Figure 4-11. Electricity generation costs excluding policy instruments for gas co-generation condensing power

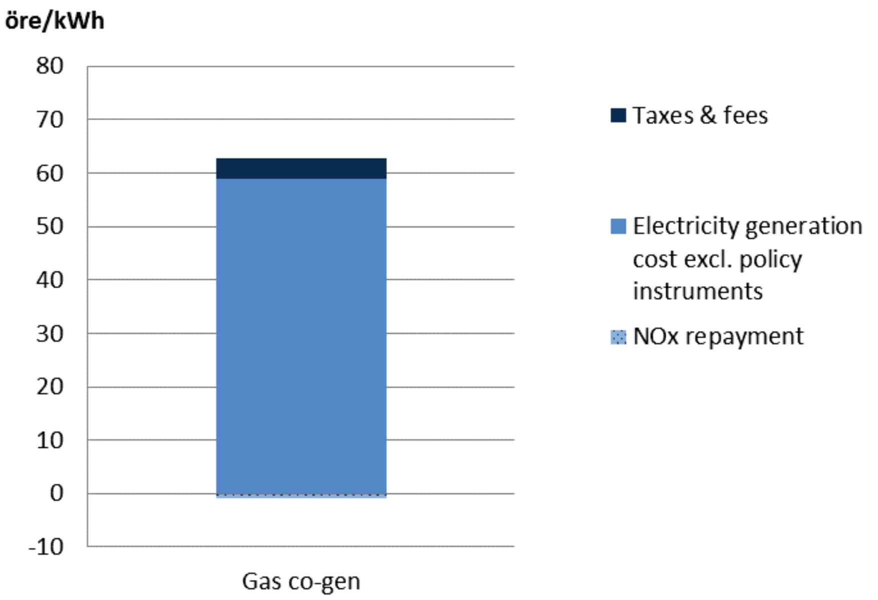

Figure 4-12. Electricity generation costs including policy instruments for gas co-generation condensing power

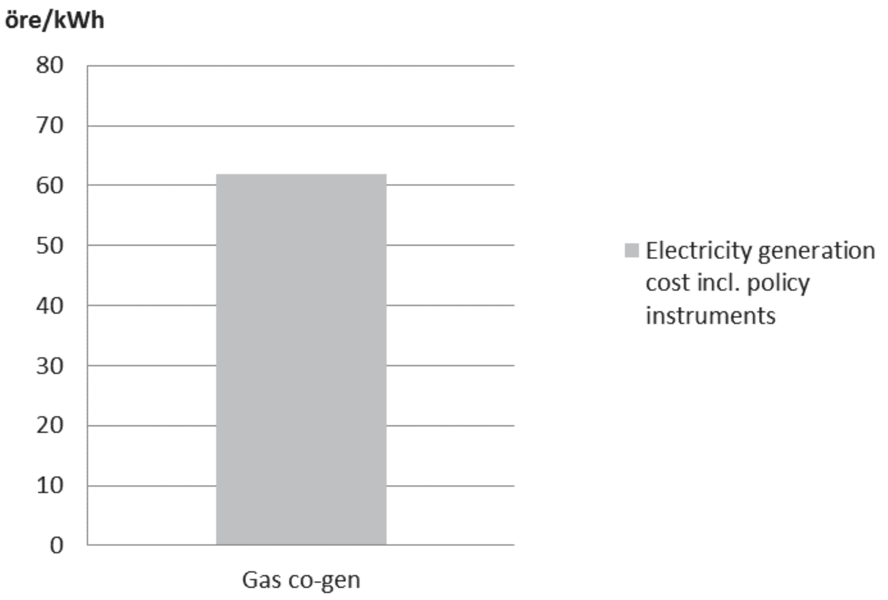

Figure 4-13. Resulting electricity generation costs including policy instruments for gas co-generation condensing power

4.4 Nuclear power

4.4.1 Technology description

Nuclear power is based on water being evaporated through heat emitting nuclear reactions in a nuclear reactor and is passed through a steam turbine via a generator to generate electricity. A schematic diagram of a nuclear power plant with boiling water reactor is illustrated in Figure 4-14.

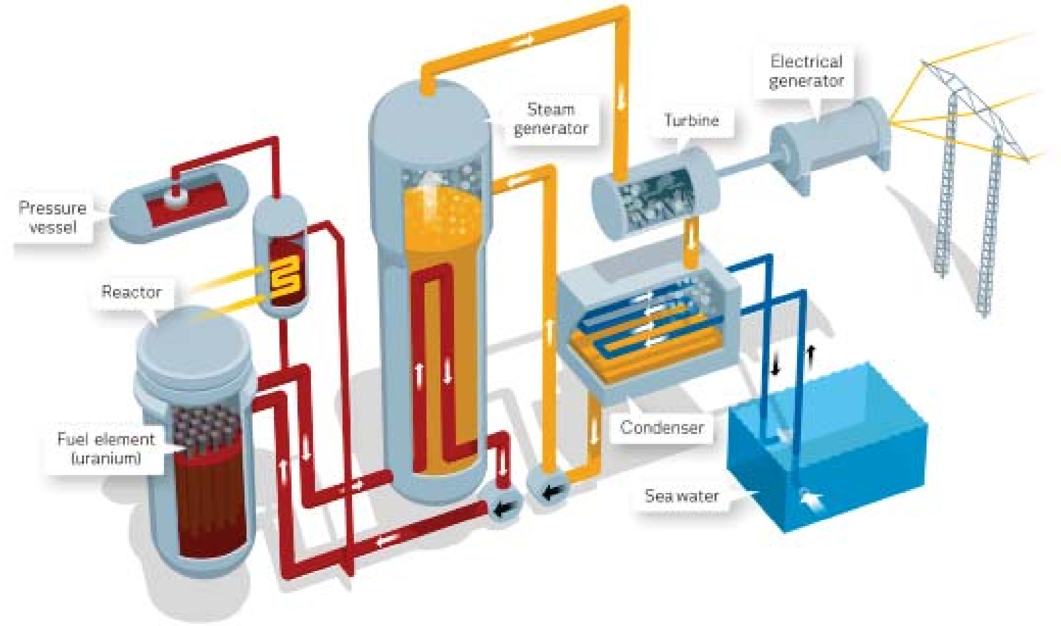

Figure 4-14. Schematic diagram of a nuclear power plant with boiling water reactor. Source: Vattenfall [39]

There are several different reactor types and technologies that have been developed over a long period of time that are usually divided into different generations; the majority of today's commercial reactors are Generation II. The technology being built today and that will be built in the near future in the West are mainly reactors called Generation III and III+. The technology has evolved from the experiences of previous generations and is primarily characterised by advanced safety systems. Some nuclear reactors of Generation III+, for example, use passive safety systems for cooling, which are activated through natural laws, instead of, or in addition to, electrical and mechanical systems. These passive safety systems are consequently much simpler than active systems as the passive safety systems do not require the same scope of help systems that are available at today's power plants.

Another characteristic of Generation III is that reliability has improved with the introduction of more durable materials and robust structures. Preconditions for a better economy are also in place when the smaller amount of construction materials and fewer components per installed power are used in relation to older generations.

Areva's EPR *(European Pressurised Reactor)* is an evolutionary design (development of previous concepts) of Generation-III which has been designed with the capability to handle hard crashes without having to evacuate. It has been designed to be able to handle and cool a core meltdown. A double containment vessel provides extra protection against external events. EPR also has a highly developed physical separation process for redundant safety systems, reducing the risk of Common Cause Failures (CCF). The net efficiency of an EPR plant is 35-37% [40].

Westinghouse AP1000 is a revolutionary design (new concept) of Generation III+ and is designed with passive cooling of the reactor containment and is therefore not as dependent on pumps and external electricity reactors with active cooling. Systems designed to take advantage of the natural laws of gravity, natural convection and circulation are used instead in order to establish the cooling required. With the smaller sizes of electrical and mechanical safety systems, the reactor is much smaller and therefore less expensive per installed power compared to the corresponding reactors of the same generation with active systems.

Suppliers of nuclear reactors include Areva (France), Westinghouse (USA), GE-Hitachi (US/Japan), KHNP (South Korea), Mitsubishi Heavy Industries (Japan), Rosatom (Russia), Candu (Canada) and CNNC & SNPTC (China) [41].

4.4.2 Development trends

Future reactors, Generation IV, lie far into the future and will be designed to ensure that major accidents can be excluded. Another important feature concerning the majority of these reactors is that they should be able to use nuclear waste as fuel. This means that the storage life of high-level waste can be reduced from 100,000s of years to less than 500 years. Reprocessing of spent fuel is a prerequisite. Focus is thereby moving from today's reactors with thermal neutron spectra to completely different concepts such as fast neutron spectra originally proposed because of better fuel utilisation. Interest has been renewed as additional reasons have emerged including the minimisation of waste and non-proliferation.

Today there are more than 430 nuclear reactors in operation around the world and 70 new ones are being built [42].

The US is building its first reactors in 30 years following the accident in Harrisburg in 1979, and more are planned. Among other things, two of the Westinghouse AP1000 by SCE&G at VC Summer NPP, are being built in South Carolina and two AP1000s by Georgia Power at the Vogtle Electric Generating Plant in Georgia. All of the reactors are scheduled to be operational around 2017-2018. To support the expansion of nuclear power, the US government is issuing loan guarantees, including USD 6.5 billion to Georgia Power [43].

In Europe, reactors are being built and planned in several locations;

- Finnish nuclear energy company *Teollisuuden Voima Oyj* (TVO) is constructing an EPR of 1,600 MW_{elec}, Olkiluoto 3. The construction is long overdue and would have been completed in 2009 but currently has no set date for commissioning. The last communicated schedule for a commissioning date at the time of writing is late 2018.

- The state owned French energy company *Electricité de France* (EDF) is constructing an EPR of 1,630 MW_{elec}, Flamanville 3. The construction is delayed and is expected to be completed in 2016.

- Finnish nuclear energy company Fennovoima plans to build an AES-2006/VVER1150 from Rosatom. The Hanhikivi 1 power plant which is planned for construction in northern Finland is expected to be operational around 2024.

- France's EDF plans to build two Areva EPRs of 1,600 MW_{elec} at Hinkley Point C in the UK which is expected to be completed in 2023. It is worth mentioning that EDF has negotiated a guaranteed fixed price of electricity from Hinkley Point C of GBP_{2012} 92.5/MWh, equivalent to about SEK 0.90/kWh, for 35 years [44].

In Russia and Asia, the expansion of nuclear power has been more continuous than in the West, and according to the UN nuclear watchdog IAEA [42] some 28 reactors are being constructed right now in China, 10 in Russia, six in India and five in South Korea.

The IAEA makes annual estimates of future global total nuclear capacity; in September 2013, it published its latest estimate, with a capacity increase of between 17-94% by 2030, as a low and high scenario [45]. Despite the fact that many older reactors are expected to close in 2030 and the accident at the Japanese Fukushima plant in 2011, the IAEA still predicts therefore expansion across the world, albeit at a slower pace than before the accident.

Sweden's nuclear power plants are old and OKG in Oskarshamn will be applying to the Land and Environment Court in 2014 for permission to shut down reactor O1 and operate it under what is called decommissioning and service operation conditions [46].

4.4.3 Technology-specific calculation conditions

Nuclear power produces electricity as a base load in the Swedish electricity system and it is therefore targeted to have as many expected full-load hours as possible. The expected full load hours are set to 8,300 hours per year with an availability of 95% resulting in a capacity factor[23] of 90%. This compares with operating experiences from Finland which on average over the past 10 years have a capacity factor of 95% [47].

The electric conversion efficiency is applied to correspond to Areva's EPR at 36% as described in Chapter 4.4.1.

[23] The capacity factor is the ratio of equivalent full-load hours and hours over a year, 8,760 hours.

Table 4-13. Technology-specific calculation requirements for nuclear power

Parameters	Value	Unit
Type of fuel	Nuclear fuel	-
Expected full load hours	8,300	h/year
Availability	95 %	-
Resulting full-load hours	7,885	h/year
Electric output gross	1,720	MW
Electric output net	1,600	MW
Electric conversion efficiency*	36 %	-

* Electric conversion efficiency is defined as net electricity through thermal output.

4.4.4 Costs

Investment costs

Estimating the investment costs for new nuclear power plants in Sweden is tricky. Although several reactors are under construction in Europe (see above), these have not yet been completed, which is why we have no up to date references for the total costs incurred. Moreover, it is difficult to generalise when the investment will differ from case to case and country to country. Factors affecting the cost are the current competitive situation but also aspects such as the cost of labour in that specific country. Additional factors that have an impact are the type of reactor, the demands the owner has, as well as the design and implementation of the project method, such as how responsibility and risk are allocated between supplier and owner. A further complication is that data from suppliers is commercial in nature and is therefore frequently kept confidential.

Cost data in different references spans a wide range and it can be difficult to decipher what is included in the presented costs which calls for great caution and keen source criticism. It is sometimes unclear whether the financial costs over the construction period are included, which can be extensive for investments in nuclear power plants, or if there is a so-called *overnight* cost. Moreover, it can be difficult to know if the figure only covers the cost of the actual construction or includes the owner's expenses for project planning and surrounding structures such as power lines, cooling water routes, simulator plants and other infrastructure. In general, the cost of the EPC accounts for 80% of the total cost, the remaining 20% consists of the owner's expenses.

Studies from several international organisations and press releases concerning ongoing construction form the basis for the estimation of the cost of investment in new nuclear power in Sweden, and a selection is presented below;

- The European Commission [48] conducted a thorough investigation in 2013 into the costs of new nuclear power and arrived at an investment cost for a FOAK reactor as the equivalent of SEK 37,000 to 48,000/kW_{elec} (overnight) and an LCOE corresponding to SEK 0.40 - 0.57/kWh at a 5% cost of capital.

- The UK's *Department of Energy and Climate Change* (DECC) estimates a range of investment cost of the “First-of-a-kind” -nuclear power plant to between SEK 40,000 and 54,000/kW_{elec}, probably including construction interest [49].

- The US's *Energy Information Administration* (EIA) has estimated investment costs excluding construction interest for two AP1000 (2,234 MW_{elec}) at a cost of SEK 36,300/kW_{elec} [26].

- The UN's nuclear watchdog IAEA collects investment costs from its more than 160 member countries and presents them based on region, excluding finance costs during construction [50]; Asia at SEK 10,300/kW_{elec}, Japan/Russia at SEK 19,800/kW_{elec}, the EU/US at SEK 23,000-39,000/kW_{elec}. The IAEA also says that their earlier studies underestimated the costs and that they have risen by over USD 2,000/kW_{elec} (SEK 13,000/kW_{elec}) over ten years, mainly due to increased awareness about the cost of ownership.

- *The World Energy Council* published an estimated total investment cost for new nuclear power in the EU/US in 2013 as USD 6,520/kW_{elec} (SEK 43,000/kW_{elec}), probably including financing costs over the construction period [27].

- The Finnish news channel Yle writes in 2012 that Areva estimates the cost of construction of the EPR reactor in Finnish Olkiluoto to correspond to the cost of construction of the reactor in Flamanville in France which had previously been estimated at EUR 8.5 billion, equivalent to about SEK 46,000/kW_{elec} at the then exchange rate [51]. Construction interest is most likely included the cost. However, since the estimate the construction of Finnish Olkiluoto 3 has been delayed further and in 2014 has entered its tenth year of construction [52]. The first estimate of the cost of the Olkiluoto 3 came in at just over EUR 3 billion in 2003 [51].

- France's EDF plans to build two Areva EPR 1,600 MW_{elec} at Hinkley Point C in the UK for an approximate total cost of GBP 16 billion at 2012 currency levels, equivalent to about SEK 53,000/kW_{elec}. Financial expenses during construction are probably included. Reactors are expected to be operational in 2023 [53].

- The US company Georgia Power Co. is constructing two AP1000 (Vogtle 3 & 4) which are estimated to cost a total of USD 14 billion, which is equivalent to approximately SEK 42,000/kW_{elec}, which is planned to be operational in 2017 and 2018 respectively [54].

Based on the available references in this project, a best estimate of the “over-night” cost of a new reactor with 1,600 MW_{elec} output is estimated at SEK 64 billion, which then includes the above mentioned expenses for the owner, but not financial costs during construction. Including the financial costs, the investment cost is around SEK 77 billion. Converted to SEK/kW$_{elec}$ these numbers are equivalent to SEK 40,000/kW$_{elec}$ (overnight) and SEK 48,300/kW$_{elec}$ (in total, including financial costs during construction). This is an increase from last time, in 2011, prepared (Swedish) investment costs of over 40% [1], which in turn increased from 2007 by almost 90% [10].

As reported above, an investment cost is assumed that is on par with the current "first-of-a-kind" projects in Europe and the United States. As more reactors have been completed, it is likely that the costs will fall, for example, due to suppliers' development costs for the design reducing.

The financial cost has been calculated for a construction period of six years[24]. Asian countries that have been constructing nuclear power plants on a continuous basis have shorter construction times, for example, the average time for construction in South Korea is 5 years[25]. The construction of Olkiluoto 3 in Finland has dragged on and the whole project is now expected to take at least 12 years. However, it is the first reactor being built in the West for many years and also the first reactor ever from Areva's EPR. It is likely that future projects will run more smoothly when, for example, the subcontractor organisation becomes more well-established.

The depreciation period for nuclear power is set to 40 years.

Nuclear power has seen a reinvestment in the calculations year 25 to cover the replacement of some major components such as turbines and generators. The sum of this has been roughly measured at an estimated SEK 5 billion, which is then recalculated at present value. It should be noted that this reinvestment gives a very small contribution to the cost of production, at about SEK 0.006/kWh.

Operating and maintenance costs

For nuclear power plants, regulatory costs for operation and maintenance (O&M) are indicated as a rule that only relate to production, i.e. in SEK/MWh$_{elec.}$ The average cost of O&M for Ringhals and Forsmark in 2008-2012 are, was according to the annual reports, SEK 97/MWh$_{elec.}$ The average cost of waste management amounts to SEK 16/MWh$_{elec.}$ The fees for handling residual waste rose in 2012 by 120% from an average of SEK 0.01 to 0.022/kWh$_{elec}$ which apply until 31 December 2014. A proposal for the coming 3-year period that has been submitted by SKB means further increases in charges, partly due to the scheduled operating times being extended for several Swedish reactors, which produces more waste to dispose of [17].

---

[24] The construction period refers to the time from the first major payment (the casting of the bottom plate for the reactor building) until the plant is completed, equipment supplied and commercial operation is in progress. This definition means that the time for licensing, preparatory ground work, procurement, and so on is not considered as major capital costs do not normally occur at this time.

[25] Construction times for the world's reactors can be found in the IAEA PRICE database. http://www.iaea.org/programmes/a2/

Based on O&M costs for Forsmark and Ringhals together with increased charges for residual waste treatment, the total O&M cost is set to SEK 110/MWh$_{elec}$, which is on par with the EIA's estimate [26]. This includes ongoing investments equivalent to a few hundred million per year, waste management, demolition of the plant and charges such as Studsvik fees[26].

For nuclear power plants with passive safety systems, which are lacking several maintenance-demanding electrical and mechanical systems for cooling, the O&M cost will probably be less. However, today there is a lack of operating experiences from electricity-generating reactors of 1,600 MW$_{elec}$ with passive cooling.

Fuel costs
Nuclear fuel was estimated by the World Nuclear Association (WNA) to cost SEK 43/MWh$_{elec}$, based on a uranium price of USD 130/kg U_3O_8 and a burnup fraction of 45 MWd/kg[27] [9]. It is possible that the uranium price will increase in the future. The cost of uranium is only a part of the fuel cost, about 45%, and the cost of fuel, in turn, represents less than 10% of nuclear energy's total generation costs. Even fairly large price increases in uranium may therefore only have marginal effects on production that is dominated by the cost of capital. Additionally, nuclear energy companies often purchase uranium with long-term contracts, which reduces the sensitivity to changes in the price of uranium.

Summarised costs
Costs and policy instruments for nuclear power are summarised in Table 4-14.

[26] The Studsvik fee is the fee that nuclear power companies pay for the decommissioning of certain activities at Studsvik. The fee finances the management of certain radioactive waste and is paid into the Nuclear Waste Fund.
[27] New reactors will likely be associated with higher burnup fractions.

Table 4-14. Summarised costs and policy instruments for nuclear power

Parameters	Value	Unit
Specific investment	37,200	SEK/kW$_{elec, gross}$
Specific investment	40,000	SEK/kW$_{elec, net}$
Construction period	6	year
Depreciation period	40	year
O&M	110	SEK/MWh$_{elec}$
Fuel price	43	SEK/MWh$_{elec}$
Reinvestment	5,000	MSEK
Time between initial and reinvestment	25	year
Output tax	5.4	öre/kWh$_{elec}$
Property tax	0.3	öre/kWh$_{elec}$

4.4.5 Results

Annual production, costs and the resulting electricity generation cost for nuclear power are summarised inTable 4-15 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments. For nuclear power, the investment cost is by far the largest cost item, and it is also the most uncertain. As described in Chapter 4.4.4 an investment cost of SEK 40,000/kW$_{elec}$ an estimate on par with the “first-of-a-kind” projects in Europe and the US based on a large range of different technologies, regions, reports and projects.

As with the other power source, a cost of capital of 6% has been used, although for new nuclear power this is probably an unrealistically low interest rate with respect to the risks associated with the construction of new nuclear power plants. Chapter 5.3.1 presents a sensitivity analysis of the cost of capital for nuclear power among others.

Table 4-15. Results for nuclear power with 6 % cost of capital

Parameters	Value	Unit
Production		
Electricity generation	12,616	GWh/year
Costs		
Capital cost	38.2	öre/kWh$_{elec}$
O&M cost	11.0	öre/kWh$_{elec}$
Fuel cost	4.3	öre/kWh$_{elec}$
Reinvestment	0.6	öre/kWh$_{elec}$
Taxes & fees	5.7	öre/kWh$_{elec}$
Results		
Electricity generation cost without policy instruments	54	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	60	öre/kWh$_{elec}$

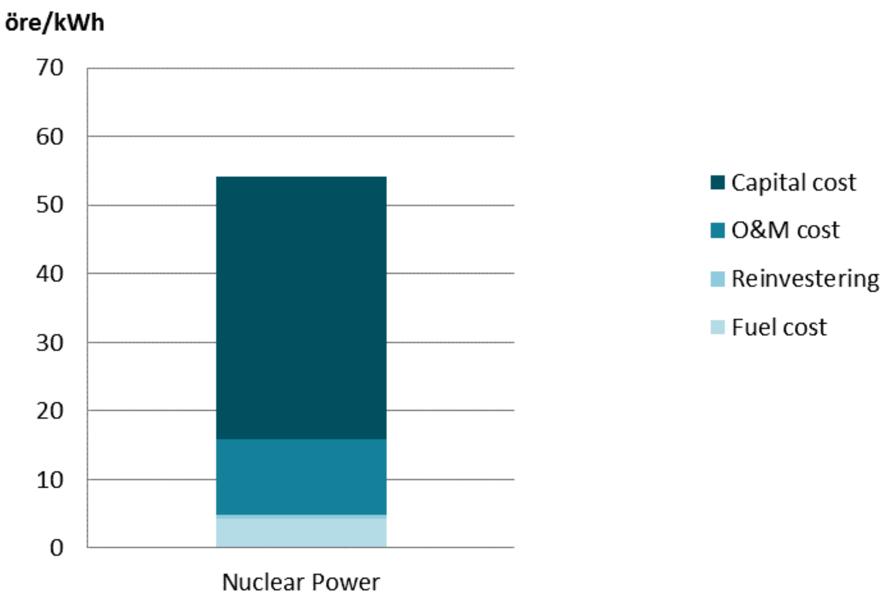

Figure 4-15. Electricity generation costs excluding policy instruments for nuclear power

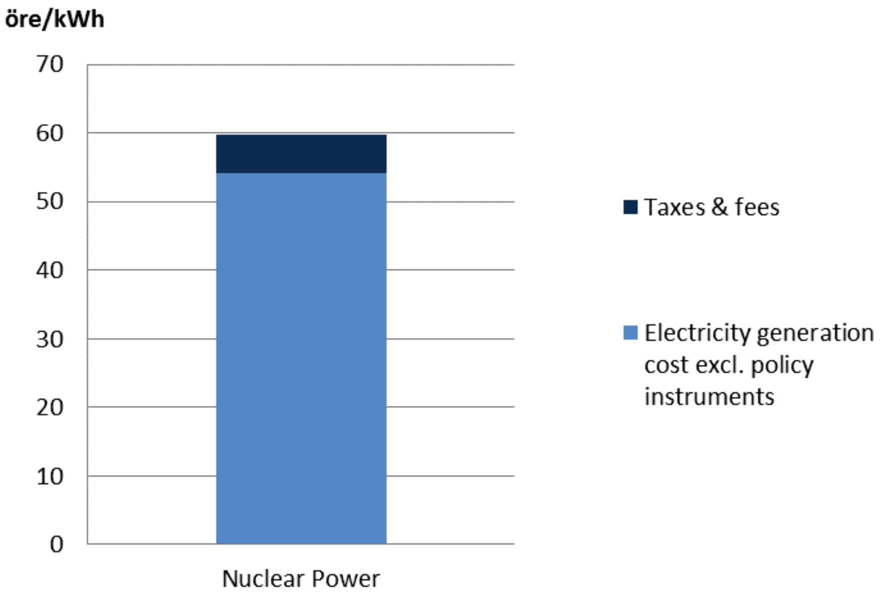

Figure 4-16. Electricity generation costs including policy instruments for nuclear power

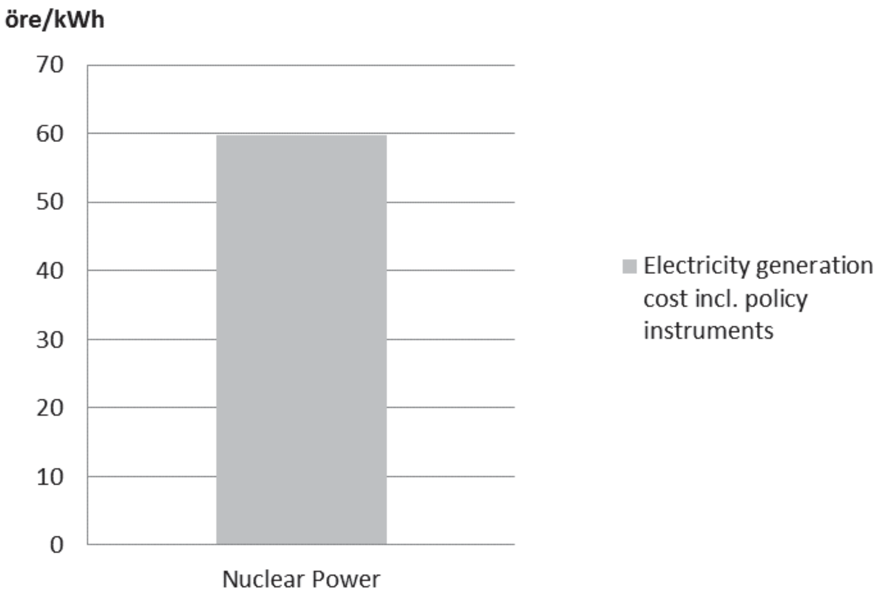

Figure 4-17. Resulting electricity generation costs including policy instruments for nuclear power

4.5 Gas co-generation

4.5.1 Technology description

Gas turbines are described in Chapter 4.2 and gas co-generation plants are described in Chapter 4.3. The only technical difference between gas co-generation and gas co-generation condensation is that the cooling is performed using district heating in a co-generation plant. The things that also differ are the operation strategy and design philosophy of the plant as there is a heat source that places demands.

The electric conversion efficiency varies depending on how the system is laid out, on which alpha value applies, and on how the plant is run. The alpha value of the plant, i.e. the ratio between electric output and district heating output depends on the operating strategy that led to the design of the plant. Rya co-generation plant in Gothenburg has an alpha value of less than 0.9 [55] and therefore produces relatively more heat and consequently focuses on a high overall efficiency. The Öresund plant in Malmö, by contrast, has an alpha value of about 1.6, while focusing on electricity generation [56]. The total efficiency for gas co-generation is high, Rya co-generation plant in Gothenburg reaches as much as 92.5% [55].

A gas co-generation plant of 150 MW_{elec} can be constructed with multiple turbines and various configurations. A common configuration is that the exhaust from two gas turbines are led to two waste heat boilers producing steam for a steam turbine. For this size, the steam cycle usually has two vapour pressures and no superheating plant. Small plants of 40 MW_{elec} are often constructed in a similar manner but usually have a slightly lower electric conversion efficiency.

The two output sizes that are compared in the report today are on the low side compared to the sizes being built in Europe today.

4.5.2 Development trends

Chapter 4.3.2 describes the trends for gas co-generation plants in general which also includes gas co-generation plants.

4.5.3 Technology-specific calculation conditions

Operational strategy for a gas co-generation plant of 40 and 150 MW_{elec} is planned as a rule according to the prevailing heat source. The expected full load hours are set as it is for other co-generation technologies at 5,000 hours per year. The availability for gas co-generation is high and set to 98%.

The electric conversion efficiency for a gas co-generation plant varies from plant to plant depending on the company's operating strategy and alpha value. Here the electric conversion efficiency of 49-51% is applied with an alpha value of 1.51 to 1.54 for representing systems with a focus on power generation.

Environmental values for gas turbines are collected from Göteborg Energi [34] and Swedegas [35].

Calculation conditions for gas co-generation plant are summarised in Table 4-16.

Table 4-16. Technology-specific calculation conditions for gas go-generation power plant, 40 and 150 MW

Parameters	40 MW	150 MW	Unit
Type of fuel	Natural gas	Natural gas	-
Heating value	38.9	38.9	MJ/Nm^3
Expected full load hours	5,000	5,000	h/year
Availability	98 %	98 %	-
Resulting full-load hours	4,900	4,900	h/year
Electric output gross	41	154	MW
Electric output net	40	150	MW
Electric conversion efficiency*	49 %	51 %	-
Alpha value net**	1.51	1.54	-
Heat output	26.5	97.5	MW
Total efficiency	81 %	84 %	-
NO_x emissions	20	20	mg NO_2/MJ_{fuel}
Sulphur emissions	0	0	mg S/MJ_{fuel}
CO2 emissions	56.8	56.8	g CO_2/MJ_{fuel}

* Electric conversion efficiency is defined as net electricity through fuel.
** The alpha value is defined here as net electricity through net heating.

4.5.4 Costs

Investment costs

A number of investment costs for plants in Sweden and Europe form the basis for Figure 4-18. Based on the graph, the specific investment costs for a gas co-generation plant with a net electrical output of 40 MW_{elec} at SEK 11,000/kW_{elec} and 150 MW_{elect} at SEK 8,500/kW_{elec}.

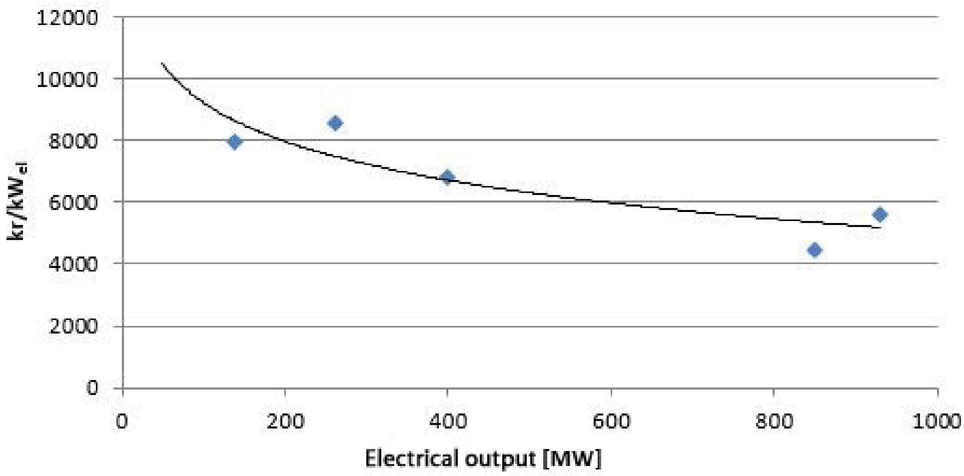

Figure 4-18. Specific investment costs for gas co-generation, based on gross electrical output.

The construction period and the depreciation period are applied as they are for gas co-generation condensation at 3 years and 25 years respectively, in accordance with Genrup and Thern [31].

Operating and maintenance costs

Operating and maintenance costs for gas co-generation plants have been set to a variable cost of SEK 25/MWh$_{elec}$ and a fixed cost of SEK 100/kW$_{elec}$ for 40 MW$_{elec}$ and SEK 90/kW$_{elec}$ for 150 MW$_{elec}$ ([26], [36]). These costs have been checked with the plant owners.

Fuel costs

Natural gas price is handled in Chapter 3.2 and for a plant of 40 MW$_{elec}$ is set to SEK 290/MWh$_{fuel}$ and for a plant of 150 MW$_{elec}$ to SEK 280/MWh $_{fuel}$.

Summarised costs

Costs and policy instruments for gas co-generation plants are summarised in Table 4-17.

Table 4-17. Summarised costs and policy instruments for gas co-generation, 40 and 150 MW

Parameters	40 MW	150 MW	Unit
Specific investment	10,740	8,280	SEK/kW$_{elec, gross}$
Specific investment	11,000	8,500	SEK/kW$_{elec, net}$
Construction period	3	3	year
Depreciation period	25	25	year
Fixed O&M	100	90	SEK/kW$_{elec, net}$
Variable O&M	25	25	SEK/MWh$_{elec}$
Fuel price	290	280	SEK/MWh$_{fuel}$
Heat crediting*	324	324	SEK/MWh$_{heat}$
NO_x repayment	-1.5	-1.5	öre/kWh$_{elec}$
NO_x fees	0.7	0.7	öre/kWh$_{elec}$
Sulphur tax	0	0	öre/kWh$_{elec}$
Emission rights	2.1	2.0	öre/kWh$_{elec}$
Energy tax	2.3	2.2	öre/kWh$_{elec}$
CO2 tax	0.7	0.7	öre/kWh$_{elec}$
Property tax	0.5	0.5	öre/kWh$_{elec}$

* Heat crediting is described in Chapter 3.6.2.

4.5.5 Results

Annual production, costs and the resulting electricity generation cost for gas co-generation are summarised inTable 4-18 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments. Fuel costs are the largest expense item for natural gas co-generation. Heat crediting is also substantial. More about heat crediting in Chapter 3.6.2.

Table 4-18. Results for gas co-generation with 6 % cost of capital

Parameters	40 MW	150 MW	Unit
Production			
Electricity generation	196	735	GWh/year
Heat production	130	478	GWh/year
Costs			
Capital cost	18.8	14.5	öre/kWh$_{elec}$
O&M cost	4.5	4.3	öre/kWh$_{elec}$
Fuel cost	59.2	54.9	öre/kWh$_{elec}$
Heat crediting	-21.5	-21.1	öre/kWh$_{elec}$
NO_x repayment	-1.5	-1.5	öre/kWh$_{elec}$
Taxes & fees	6.3	6.0	öre/kWh$_{elec}$
Results			
Electricity generation cost without policy instruments	61	53	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	66	57	öre/kWh$_{elec}$

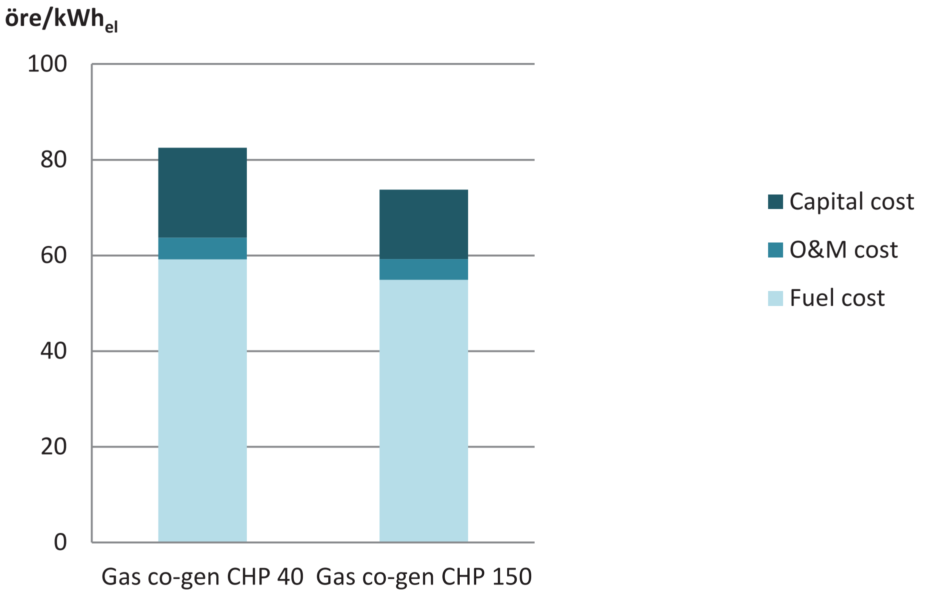

Figure 4-19. Generation costs of electricity and heat using gas co-generation, excluding policy instruments and heat crediting

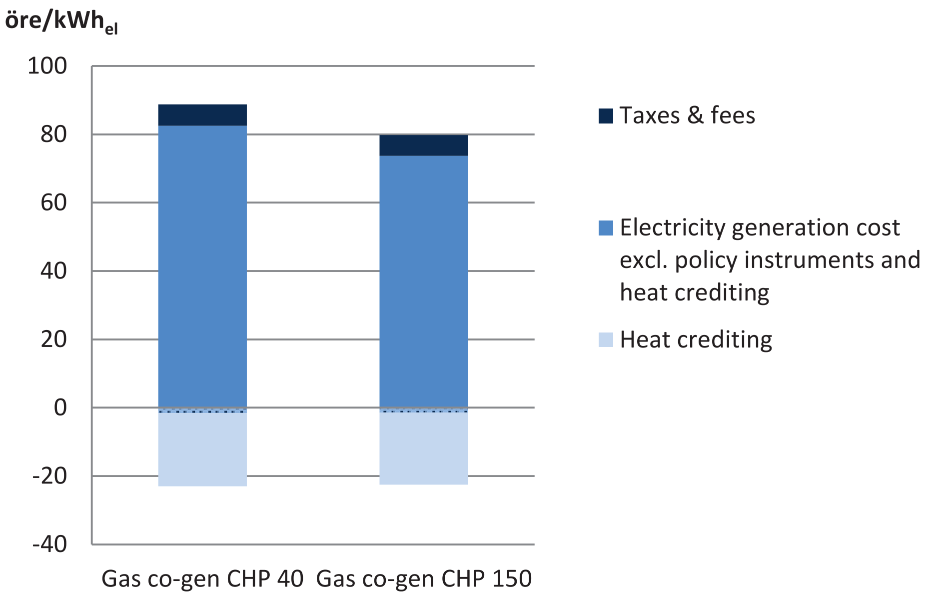

Figure 4-20. Electricity generation costs including policy instruments and heat crediting for gas co-generation

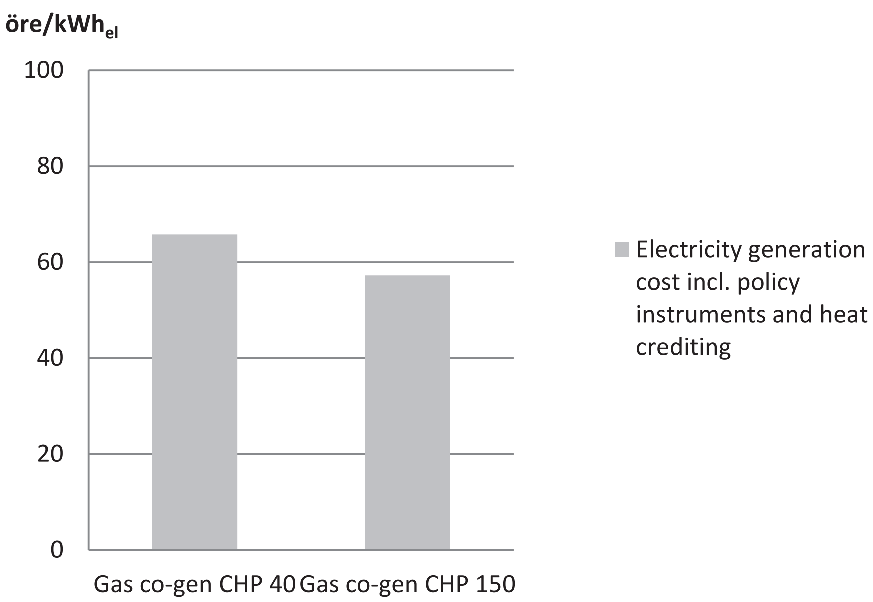

Figure 4-21. Resulting electricity generation costs including policy instruments for gas co-generation

4.6 Biomass fuel co-generation, steam cycle

This chapter presents the four cases based on biomass fuel combustion in a combustion appliance followed by a steam cycle with electricity generation in the turbine.

4.6.1 Technology description

A biomass fuel-fired co-generation plant generates electricity through biomass fuel (mainly in the form of wood chips) being introduced and burned in a hearth'. The hot gases that are formed result in turn by heating up the water that is evaporated. The steam expands in the steam turbine with a generator that generates electric current. After the steam is expanded in the turbine, it condenses to provide district heating.

A Rankine cycle, or steam cycle, is a thermodynamic energy conversion process, which in its simplest form consists exclusively of four principal components: boiler, turbine, condenser and water pump.

It is the temperature level in the condenser which determines the final pressure of the steam expansion and it is therefore an important parameter for showing how much mechanical work can be charged per kilogram of steam. At a co-generation application, heat is utilised in the condenser for generating district heating. The temperature of the outgoing cooling water, the supply temperature, then needs to be about 70-120 °C depending on the season and district heating system. This gives a saturation pressure in the range 0.3-2.0 bar (a) in the condenser. When an application is used exclusively for electricity generation (condensing power plants) a significantly lower saturation pressure occurs in the condenser, a typical value is 0.04 bar (a), and this is chiefly determined by the cooling water (in Sweden sea water) temperature, which may vary with the seasons.

Applications for the simultaneous generation of electricity and the production of process steam (industrial back pressure plants) are designed for the extraction of steam in the turbine or by setting the subsequent condenser for a higher temperature level and final pressure corresponding to the required process pressure. The amount of mechanical work in the turbine is reduced, which also reduces electricity generation to a corresponding amount when compared with co-generation or condensing power plant.

In order to increase the thermal efficiency, additional components are introduced. A number of heat exchangers in the form of preheaters are introduced where condensate or feed water is heated to the appropriate temperature before the boiler. On the hot side of the preheaters, the bleed steam from the turbine is used. Reheating is also thermodynamically favourable and means that the steam first expands to a certain pressure, about 1/4 - 1/5 of the initial pressure, and is then superheated again in the boiler before expanding to final pressure. Reheating raises the average temperature of the heat supplied to the steam cycle and also means that the steam pressure can be increased significantly without any problems with high moisture levels that are produced in the turbine's final step. The actual cycle configuration in a particular case is determined by technical/economic optimisation. Generally, the larger plants have a more advanced steam cycle and consequently higher thermal efficiency.

The boilers for biomass fuel are today frequently of the BFB (bubbling fluidized bed) or CFB (circulating fluidized bed) model. For smaller boilers, boilers of the fire-grate model can also be installed, but in this report the costs are based on fluidized bed technology. The bed material consists mainly of sand that is fluidized through combustion air being blown in. In the case of CFB, the air velocity is so great that the bed comes into circulation. The bed material and any uncombusted particles are separated from the flue gas in the cyclone and returned to the bottom of the hearth. The boiler contains an internal heat exchanger, air preheater, economiser, evaporator and superheater. The placement of these heat exchangers along the line of the boiler may vary in individual cases.

A two-phase stream, i.e. water and steam through the evaporator tubes are often carried out through self-circulation. The two phases, water and steam are separated in the boiler drum. For the higher steam pressures, forced circulation is applied and flow-through boilers are used for supercritical pressures.

Systems for fuel management are generally extensive for a biomass fuel-fired plant. It could contain a warehouse plant, several silos, reprocessing and different types of transporters. The investment cost of the systems can represent around 10% of the total construction cost. The following chapter features typical examples of steam cycle configuration, the type of boiler and steam data for the four sizes that are addressed in this report.

Plant flue gas purification is important and it must be adapted to suit the conditions for nitrogen oxide and particulate emissions that apply in each case. The equipment for flue gas treatment usually consists of an electrostatic filter for the separation of dust. Depending on how tough the nitrogen oxide conditions are that are set for a plant, either an SNCR system (Selective Non-Catalytic Reduction) or SCR system is required.

General performance

In a Swedish pilot study [57], the technical/economic conditions for raising steam data for biomass fuel-fired plants has been studied. The same study also presents typical performance for today's plants. The sizes included in this study are 10 MW_e, 30 MW_e and 80 MW_e. Fuel use, sometimes called total efficiency, is quite independent of size and steam data.

Flue gas condensation is today profitable for wet biomass fuel and with condensation, the total efficiency can be increased significantly. Total efficiency is generally based on the fuel's lower heating value and depends on the moisture content of the biomass fuel and on the district heating water's return temperature. At 45% moisture content in the biomass fuel and an assumed return temperature of 50 °C, the total efficiency will be approximately 105%. Additionally, if moistening and preheating of the combustion air is used, the total efficiency could be increased to about 113%. The extra energy taken from the flue gas in the form of sensible and latent heat, which means that the flue gas condition following flue gas condensing and before the chimney is about 35 °C, with a moisture content of 5%.

In this report, flue gas is assumed in all cases. For a new co-generation plant, the heat demand is the governing parameter for the size of the plant. Flue gas condensation means that the alpha value (ratio of net electricity output and district heating) is reduced and consequently electricity generation drops for a given heat requirement.

Sometimes a different alpha value is used which is calculated instead as electricity from the generator through the heat from the condenser, in other words this does not include the heat produced in the flue gas condensation. This alpha value ("alpha value gross") shows how efficient electricity generation is in relation to the district heating produced from the boiler. This latter alpha value is shown for a number of different plants in Figure 4-22. These values, which are verified with the supplier, have been used in the study to calculate the electricity generation for the different cases.

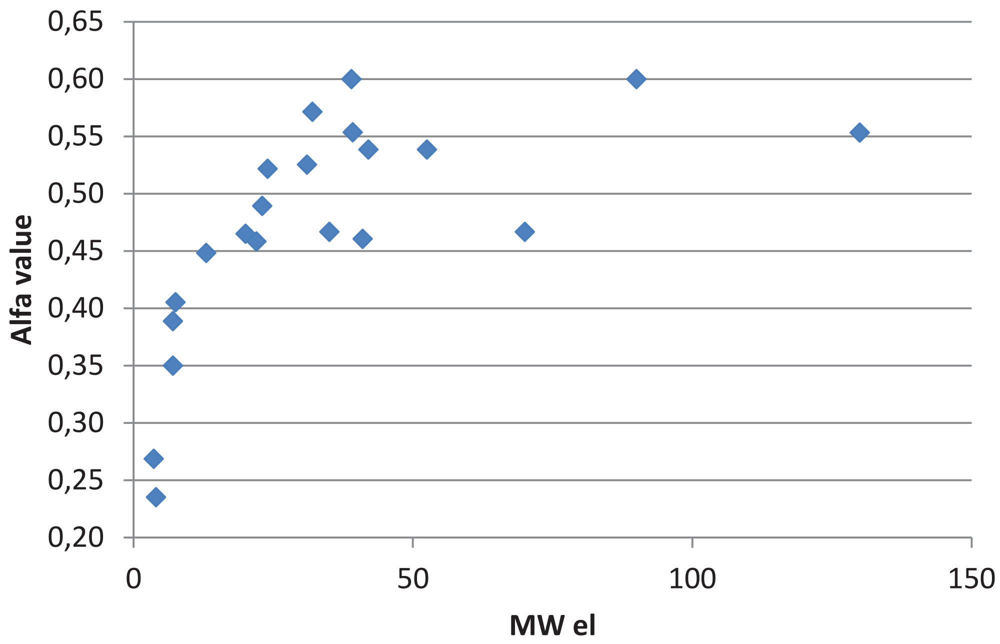

Figure 4-22. Alpha value gross (key ratio, electricity/heat from condensers) for a number of biomass fuel-fired co-generation plants.

Size 5 MW$_{elec}$

This plant is composed of a biomass fuel-fired boiler and a steam turbine with one or two branch offs, one to the air superheater and one to a feed water tank (MV-tank), see Figure 4-. The configuration varies from plant to plant. More preheaters would be thermodynamically favourable but this is not technically/economically viable. A reheating process of this size is not considered economically viable as the cost of the turbine and boiler increases. The boiler may be of the fire-grate or BFB model, and flow through the evaporator tubes takes place through natural circulation.

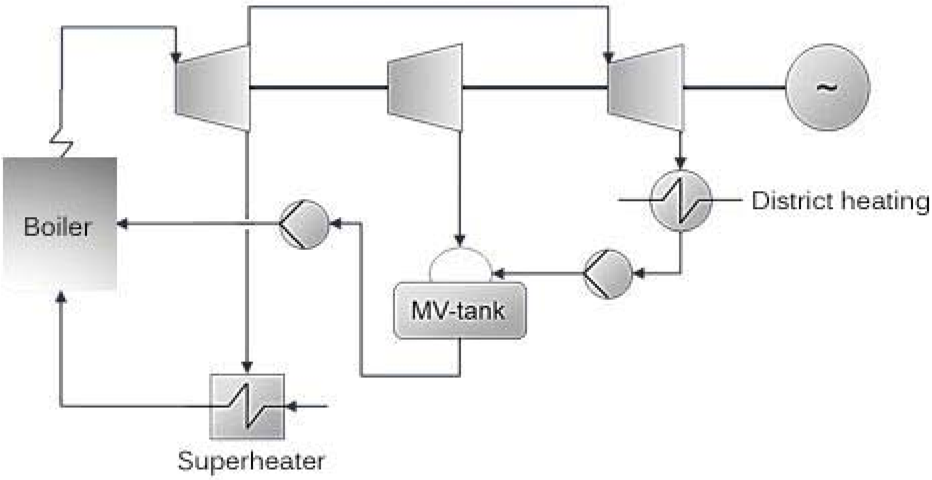

Figure 4-23 Biomass fuel co-generation, 5 MW_{elec} process.

Typical steam data (at the turbine inlet) with today's technology is 60-90 bar and 480-500 °C. The net electric conversion efficiency is 23-30%, and the alpha value with flue gas condensation is about 0.19 to 0.25 [58].

Size 10 MW_{elec}

This size is built up of a biomass fuel-fired boiler and a steam turbine with three branch offs, one to the feed water tank (MV-tank), one to a low-pressure preheater (LTFV) and one to a high-pressure preheater (HTFV), see Figure 4-. More preheaters would be thermodynamically favourable but this is not technically/economically viable. A reheating process of this size is not considered economically viable as the cost of the turbine and boiler increases. The boiler may be of the BFB or CFB model, and flow through the evaporator tubes takes place through natural circulation.

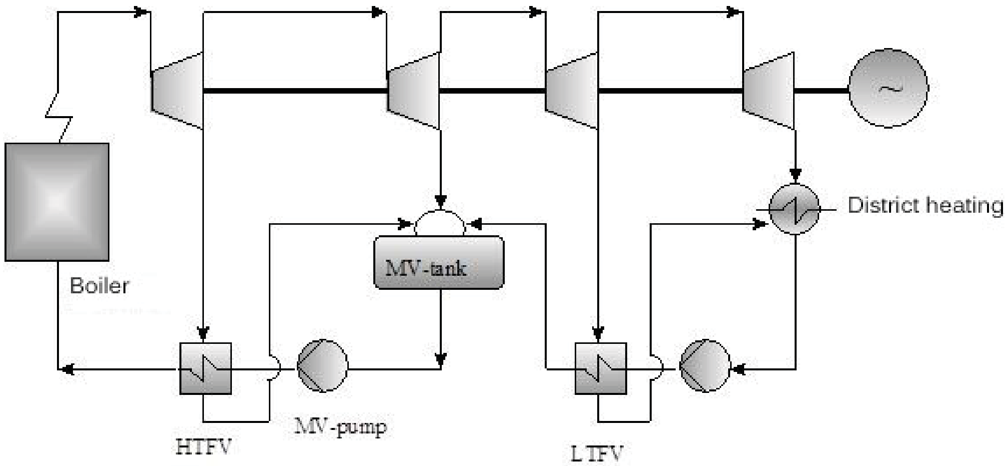

Figure 4-24. Biomass fuel power plant, 10 MW_{elec} process

Typical steam data (at the turbine inlet) with today's technology is 90 bar and 520°C. The net electric conversion efficiency is 27 %, and the alpha value with flue gas condensation is about 0.35.

Size 30 MW_{el}

At this size, the steam cycle often has two HTFVs, one MV tank, one LTFV and a mixing preheater (BLFV), see Figure 4-25. The latter mixes condensate from the two condenser elements which work with different pressures and heat loads. A division of the condenser into two stages is beneficial because some of the steam may expand to a lower final pressure. Even for this size, reheating is not considered technically/economically viable. The boiler may be of the BFB or CFB model, and flow through the evaporator tubes takes place through natural circulation.

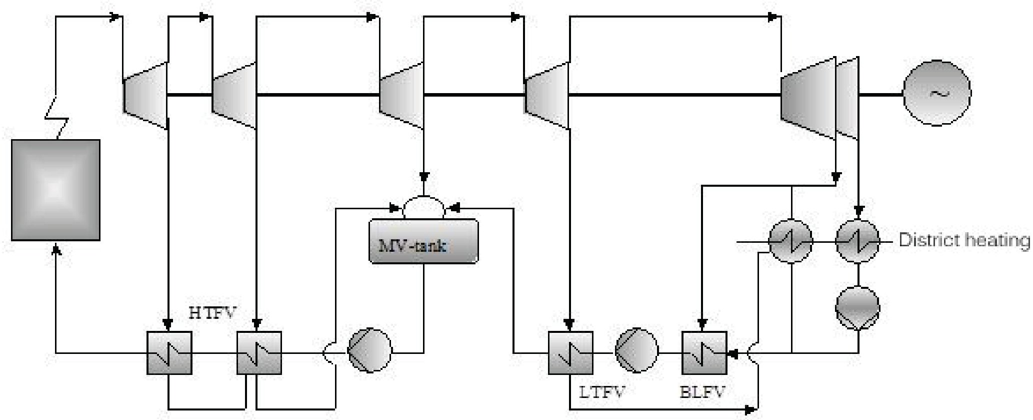

Figure 4-25. Biomass fuel power plant, 30 MW_{elec} process

Typical steam data with today's technology is 140 bar and 540°C. The net electric conversion efficiency is 28 %, and the alpha value with flue gas condensation is around 0.37-0.38.

Size 80 MW_{el}

The size 80 MWe may be considered to belong to the upper part of the power range with regard to biomass fuel combustion in Sweden. The steam cycle could have three HTFVs, one LTFV, one BLFV and two condenser elements, see Figure 4-26. For this size, reheating is technically/financially generally profitable. The boiler may be of the CFB model, and flow through the evaporator tubes takes place through natural circulation or forced circulation.

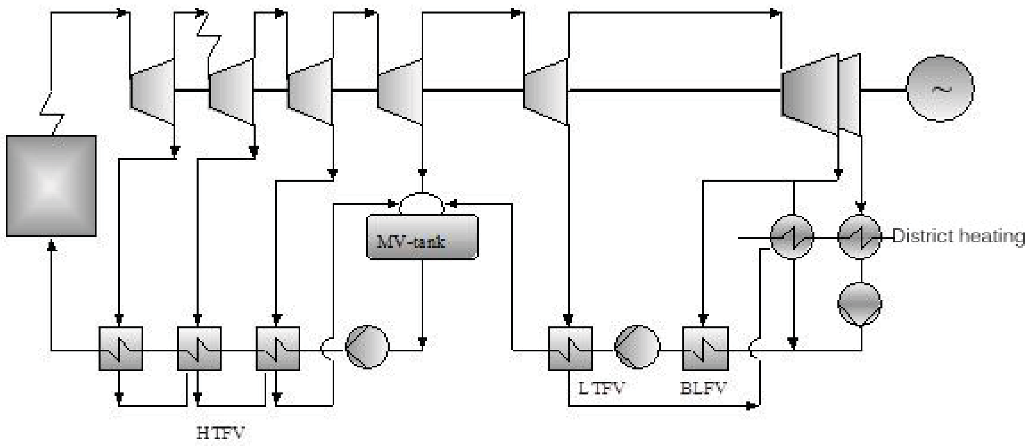

Figure 4-26. Biomass fuel power plant, 80 MW_{elec} process

Steam data with today's technology is up to 140 bar and 560 °C (for example KVV8 at the Värta plant). The net electric conversion efficiency is around 31% and the alpha value with the flue gas is around 0.41 to 0.42.

4.6.2 Development trends

With the introduction of electricity certificates and because of rising electricity prices up to 2010, interest has grown in achieving the highest possible electricity output from a plant. For today's plants, high electric conversion efficiency has essentially been assumed to be satisfied by technical solutions such as the development of loop seal superheaters in CFB applications. This solution seems to have led to a commercial establishment by steam temperatures in the range 540-560 °C, the higher level applies to larger units. Development towards levels up to 600 °C is not assumed to be commercially viable until 2020-2025. The trend towards higher steam data in commercial plants should be related to the price of electricity, which after peaking in 2010 has exhibited a downward trend.

4.6.3 Technology-specific calculation conditions

The electric conversion efficiency and alpha values listed below are balancing values for a number of newer plants and information from suppliers. Nitrogen oxide emissions are estimated based on a number of plant emissions specified in the NOx register for 2012 [59]. The technology-specific calculation assumptions used in calculating the electricity generation cost are given in Table 4-19.

Table 4-19. Technology-specific calculation conditions for biomass fuel-fired, co-generation 5-80 MW

Parameters	5 MW	10 MW	30 MW	80 MW	Unit
Type of fuel	Forest chips	Forest chips	Forest chips	Forest chips	-
Heating value	2.6	2.6	2.6	2.6	$MWh/tonne_{fuel}$
Expected full load hours	5,000	5,000	5,000	5,000	h/year
Availability	96 %	96 %	96 %	96 %	-
Resulting full-load hours	4,800	4,800	4,800	4,800	h/year
Electric output gross	5.8	11	33	88	MW
Electric output net	5	10	30	80	MW
Electric conversion efficiency*	22 %	27 %	28 %	31 %	-
Alpha value net**	0.27	0.35	0.37	0.41	-
Alpha value gross***	0.40	0.50	0.53	0.60	-
Condensation heat-output	14	22	62	147	MW
RGK effect	4	7	19	47	MW
Total efficiency	104 %	105 %	105 %	106 %	-
NO_x emissions	70	60	40	40	mg NO_2/MJ_{fuel}
Sulphur emissions	0	0	0	0	mg S/MJ_{fuel}
CO2 emissions	0	0	0	0	g CO_2/MJ_{fuel}

* Electric conversion efficiency is defined as net electricity through fuel.
** The alpha net value is defined here as net electricity through net heating including flue gas condensation.
*** The alpha value gross is defined as gross electricity through condensation heat

4.6.4 Costs

Investment costs

Investment costs for biomass fuel-fired co-generation plants have been estimated by bringing in the investment costs for a number of constructions that have recently been implemented or begun and will be completed within a few years (see Figure 4-27).

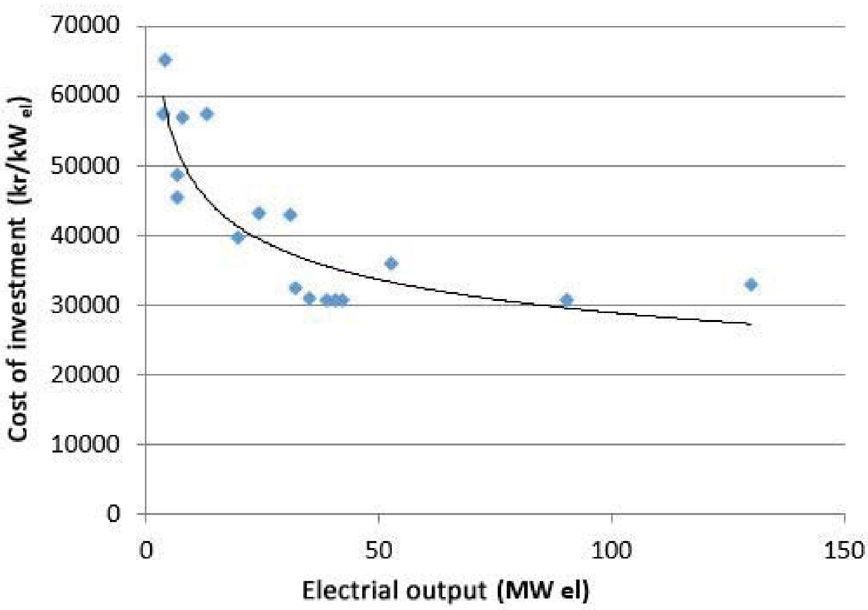

Figure 4-27. Investment costs for a number of biomass fuel-fired co-generation plants, indicated as the cost per installed electrical output i.e. gross electrical output.

Based on the investment costs compiled inFigure 4-27 the investment cost for the four boiler sizes/outputs is estimated at:

- SEK 53,900/$kW_{elec,\ gross}$ for 5 MWel
- SEK 46,800/$kW_{elec,\ gross}$ for 10 MWel
- SEK 36,900/$kW_{eled,\ gross}$ for 30 MWel
- SEK 29,700/$kW_{elec,\ gross}$ for 80 MWel

The investment costs are similar to the recent Swedish cost compilation 2011 [1], except for the larger plant that has grown more expensive since 2011. Note that the entire cost of investment in co-generation cases are charged to electricity generation and the comparison with clean electricity generating plants is not entirely representative. A biomass fuel co-generation plant is not built as there is a heat source that provides income for the heat produced. The investment cost would therefore be spread over both products: electricity and heat. This is not the case in this report but investment costs are charged to electricity generation and heat production is then credited.

Operating and maintenance costs

Variable O&M costs have been estimated to be SEK 21/MWh_{fuel} which are verified by contacting the energy companies. Fixed O&M costs are estimated to be between about 1.5% to 2.2% of the investment cost, see values for the different cases in Table 4-20.

Fuel costs
The price of biomass fuel is assumed to be SEK 200/MWh_{fuel} (see Chapter 3.2).

Summarised costs
Costs and policy instruments for biomass fuel-fired co-generation plants are summarised in Table 4-20.

Table 4-20. Summarised costs and policy instruments for biomass fuel-fired heating plants, 5-80 MW

Parameters	5 MW	10 MW	30 MW	80 MW	Unit
Specific investment	53,900	46,800	36,900	29,700	SEK/$kW_{elec, gross}$
Specific investment	62,700	51,500	40,400	32,700	SEK/$kW_{elec, net}$
Construction period	2	2	2	2	year
Depreciation period	25	25	25	25	year
Fixed O&M	1,430	1,050	700	500	SEK/$kW_{elec, net}$
Variable O&M	21	21	21	21	SEK/MWh_{fuel}
Fuel price	200	200	200	200	SEK/MWh_{fuel}
Heat crediting*	-324	-324	-324	-324	SEK/MWh_{heat}
NO_x repayment	-4.2	-3.5	-3.4	-3.1	öre/kWh_{elec}
NO_x fees	5.7	4.0	2.5	2.3	öre/kWh_{elec}
Electricity certificate**	-190	-190	-190	-190	SEK/MWh_{elec}
Property tax	0.7	0.7	0.7	0.7	öre/kWh_{elec}

* Heat crediting is described in Chapter 3.6.2.
** Electricity certificates are paid for 15 years.

4.6.5 Results

Annual production, costs and the resulting electricity generation cost for gas co-generation condensing power are summarised inTable 4-21 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments. For biomass fuel-fired co-generation it is mainly the capital cost and fuel costs that are larger, while heat crediting lowers the overall cost significantly (heat crediting is described in Chapter 3.6.2).

There is a vast difference in electricity costs depending on output, partly because the specific investment cost and the specific costs of O&M are lower for larger plants but also because larger plants have a higher electric conversion efficiency.

Table 4-21. Results for biomass fuel-fired heating plants with 6% cost of capital

Parameters	5 MW	10 MW	30 MW	80 MW	Unit
Production					
Electricity generation	24	48	144	384	GWh/year
Heat production	88	138	391	932	GWh/year
Costs					
Capital cost	105.7	86.8	68.1	55.1	öre/kWh$_{elec}$
O&M cost	39.2	29.6	22.0	17.2	öre/kWh$_{elec}$
Fuel cost	89.7	73.8	70.7	64.7	öre/kWh$_{elec}$
Heat crediting	-119.2	-93.2	-88.0	-78.6	öre/kWh$_{elec}$
NO_x repayment	-4.2	-3.5	-3.4	-3.1	öre/kWh$_{elec}$
Electricity certificates	-14.4	-14.4	-14.4	-14.4	öre/kWh$_{elec}$
Taxes & fees	6.4	4.7	3.2	3.0	öre/kWh$_{elec}$
Results					
Electricity generation cost without policy instruments	115	97	73	59	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	103	84	58	44	öre/kWh$_{elec}$

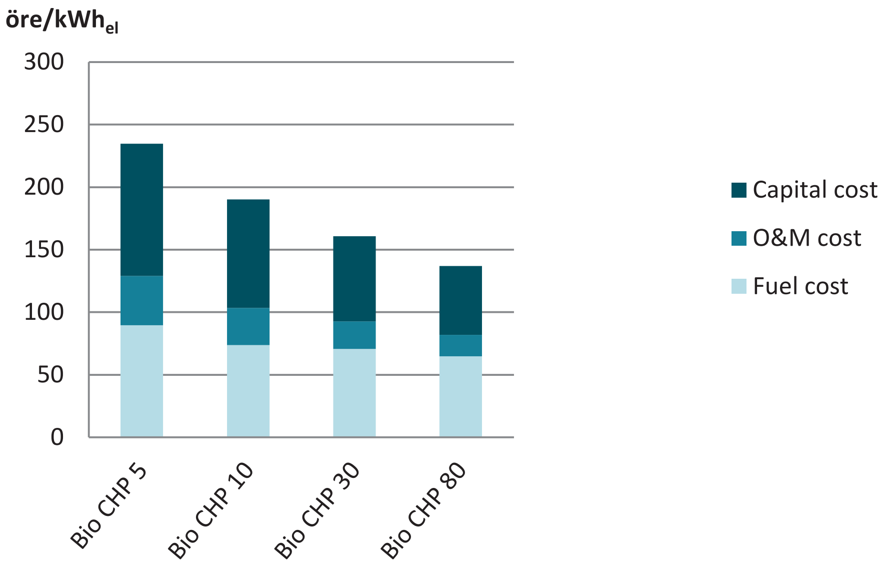

Figure 4-28. Generation costs for electricity and heating using biomass fuel-fired heating plants, excluding policy instruments and heat crediting

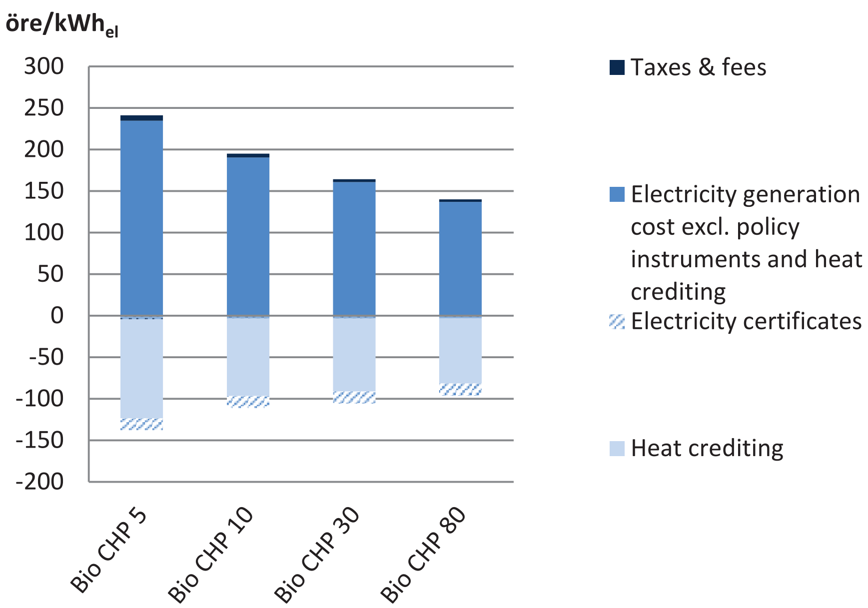

Figure 4-29. Electricity generation costs including policy instruments and heat crediting for biomass fuel-fired heating plants

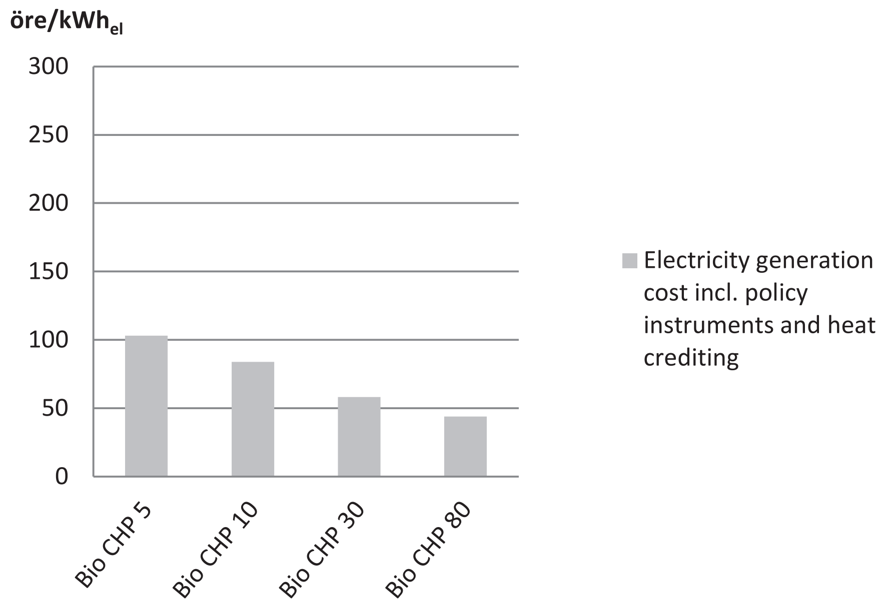

Figure 4-30. The resulting electricity generation cost including policy instruments and heat crediting for biomass fuel-fired co-generation

4.7 Waste-fired co-generation

In Sweden there are more than 30 plants that burn municipal and industrial waste. Most of the plants produce both heat and electricity and are consequently co-generation plants. According to Avfall Sverige, over 5 million tonnes of waste was incinerated in 2012, some of which was imported waste. Total production in 2012 was 13 TWh of heat and 1.7 TWh of electricity from waste incineration plants.

In most plants, both household and industrial waste was burnt and the fuel is usually inhomogeneous and can have varying energy content, normally between 10-12 MJ/kg. A reasonable value for general calculations is 11 MJ/kg, which is slightly higher than normal (humid) biomass fuel. Household waste consists of about 85% by weight of organic renewable materials. This corresponds to about 65 energy% of renewable materials. Other material is fossilised, such as plastics. Sorting of waste can be performed at different levels, such as sorting of combustible material which produces a fraction called RDF (Refuse Derived Fuel), see Chapter 4.8.

Many municipalities have introduced the sorting of household waste, which means that glass, metals, paper, plastic and compostable materials are sorted. By sorting you ensure a more homogeneous fuel fraction, which improves the operating conditions with respect to aspects like accessibility, controllability and more. In return, it is reasonable to assume that the better the waste is sorted, the less income the plant owner will earn from waste. This chapter assumes essentially the mass incineration of waste, i.e. the plant is designed for mixed (unsorted) municipal and industrial waste being burned in fire-grate boilers.

4.7.1 Technology description

The most common technology for waste incineration is the fire-grate method. For sorted and crushed waste, fluidized bed boilers are also an option. Incineration of waste sorted using fluidized bed technology is discussed in Chapter 4.8. (Rotary kilns are generally used for incineration of hazardous waste.)

Because the waste contains a lot of ash, 15-20%, along with components that increase the risk of corrosion in the hearth and the superheater tubes, this creates a waste incineration plant designed to handle the difficult fuel. Among other things, the fire-grate and hearth are designed to ensure the best possible fuel burnup. The boiler is designed with an “empty draught” where the temperature of the flue gas is lowered before it meets the superheater tubes. This means that a waste boiler will be considerably more expensive than a bio boiler. After the boiler, a very comprehensive treatment of flue gases is needed to meet high environmental standards.

Figure 4-31 shows a simplified process flow diagram for the Öresund plant's new investment, the Filborna waste-fired co-generation plant.

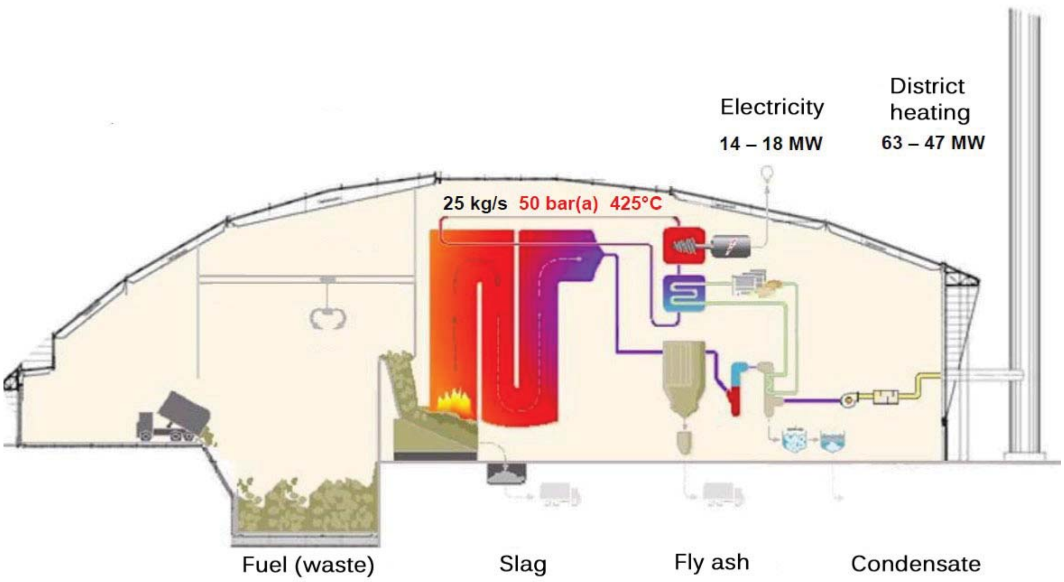

Figure 4-31. Cross-section of Filborna waste co-generation plant [60].

There are different designs of fire-grates, such as forwardly projecting fire grate, rearwardly projecting fire grate, drop grate, and others. A common feature of all of them is that the waste is fed forward on a number of parallel grate rods while it is distributed and mixed for the most favourable combustion process as possible.

Combustion air is supplied to different zones. Primary air is supplied under the fire-grate with secondary air higher up in the oven and sometimes tertiary air. The location and size of the nozzles for blowing the air, along with the supply air jet, are important for mixing and final combustion of the combustion gas. Combustion takes place at about 1,000 °C. High temperature and adequate turnover time and turbulence are required for complete burnout. When waste is an inhomogeneous fuel, very high demands are therefore placed on process control. The flue gas is cooled to about 150-200°C in a boiler consisting of one or more consecutive lines before reaching the flue gas.

Stringent environmental requirements are set for waste incineration, which means that advanced flue gas purification equipment is required. The flue gas purification method can be either dry or wet, or be a combination of both methods.

Dry cleaning is based on fabric filters in combination with the injection of absorbents, which are usually lime based. The absorbent is injected into a reactor which then reacts with the pollutants in the flue gas. The product is then separated effectively in the bag filter. Acidic components in the flue gas react with the absorbent to form calcium salts, and water vapour. Heavy metals which evaporate during combustion condense when cooling in the boiler of the dust particles in the flue gas and are separated in the porous layer dust collector. However, elements like mercury are not separated in this way as they are in gaseous form even after the boiler. Mercury capture in Swedish plants is primarily achieved using active carbon that binds mercury through absorption. The physical process is the same when dioxins bind to the fly ash/dust, which is used for its separation. The effect can be strengthened by the addition of activated carbon. Dry technologies for flue gas from waste incineration may also include the semi-dry or wet-dry methods. They are used to the same extent and satisfy emission compliance for the separation of dust, dioxins and heavy metals. For the effective separation of acid components you may need extended dosing of the absorbent(s), which is disadvantageous from a residue viewpoint. This can be solved with an extension using a dedicated scrubber.

Wet cleaning means that the flue gas is washed in a series of columns or scrubbers. In some wet systems, flue gases are cooled down for condensation. This achieves better cleaning efficiency, while the energy stored in the flue gas in the form of water vapour can be utilised. For optimum performance, there are sometimes two washing steps with different pH values, as the pH dependence is great for the solubility of, for example, sulphur dioxide. The flue gas for condensing is cooled indirectly, via a form of heat exchanger, or in direct contact with water. To ensure that all components condense, the flue gas is cooled down to around 40 °C. Before the flue gas is emitted, it may need to be reheated. The condensation step is often linked to the district heating network via a heat pump. Acidic components, especially hydrogen chloride are removed very efficiently using wet purification. The degree of separation is lower for dioxins.

The various steps of purification, wet and dry as described above, may be combined in many different ways. Even second steps occur, for example, electrostatic precipitators, which are sometimes placed before both the wet and dry treatment as an initial rough dust removal step.

The majority of the fuel ash, called slag, is fed out from the fire-grate to a water trough. Sorting and recycling of metals is then sometimes performed after cooling. Some of the slag is deposited but the bottom ash is also used as a substitute for example for natural gravel in road construction.

Flue gas purification products are classed as hazardous waste and are disposed of under safe conditions. Sometimes the ash stabilises in some way before deposition. The condensate from wet flue-gas is purified, and the slag is treated in the same manner as the dry flue gas purification products.

Performance
Waste incinerator plants usually have low steam data with both low pressure and low steam temperatures. The low pressure of the steam depends on there otherwise being a risk of corrosion in the hearth while the relatively low steam temperature is selected to avoid high temperature corrosion of the superheaters. One reason that waste is a fuel that increases the risk of corrosion is that the waste usually has a high chloride content along with the waste content of alkali metals (sodium and potassium), lead, copper and zinc. Another reason for the increased risk of corrosion is that it is difficult to avoid streaking i.e. areas where the flue gases are not burned out completely. The reducing environment that arises then accelerates the corrosion through degradation of the protective oxide layer. As a result of limited steam data, it is difficult to achieve higher gross alpha values than about 0.34 (the most recently built plants have a gross alpha value of between 0.32 and 0.34). Normal steam data is 40-50 bar (g)/400-450 °C.

4.7.2 Development trends

New types of waste are being supplied to the plants to a greater extent due to changes in waste management legislation and some of these, such as slag and hazardous waste from hospitals, require specific input and combustion technology. Waste incineration capacity has been substantially increased and several new boilers have been commissioned. This means that the import of waste will rise.

Water-cooled fire-grates are becoming more common as the calorific value of the waste now tends to increase due to the diversion of food waste and the growing proportion of industrial waste. Storage, usually the baling of waste, is becoming more common. This allows more of the waste to be utilised when demand is at its greatest.

Combustion technology has improved with the help of the qualified control and distribution of fuel and combustion air, ensuring the risk of the formation of harmful corrosive substances and emissions, not least of dioxins, decreases. This also corresponds with the new EU requirements, which indicate that the content of unburned slag must not exceed 3%. Relatively low electric conversion efficiency means that the steam data must be low (<400-450 °C) to avoid any corrosion problems. Technical solutions that facilitate the replacement of superheaters, increased knowledge of additives such as sulphur or sulphates, the co-incineration of municipal digested sludge in combination with the research and development of new materials allows the development of higher steam data.

A quest to utilise the resources of the community is driving the development of waste product management. Methods for separation and recycling of ammonia have been developed and are now being installed at the plants. Reuse of waste, such as filling material in road construction, is common in Europe and being pursued in Sweden. The industry is working with government agencies in order to develop methods for quality assurance of slag from fire-grate boilers to assess when and how it can be reused. Slag content of metals is likely to be recovered to a greater extent in the future. Various forms of stabilisation of flue gas purification products are becoming more common in urban areas in Europe with limited landfill space. In Sweden, the drivers are not as potent for this. Higher demands for the disposal of flue gas purification products, however, will be set and simpler forms of stabilisation applied.

4.7.3 Technology-specific calculation conditions

The electricity efficiencies and alpha values given below are an average of the newer plants that have been or are being constructed. Nitrogen oxide emissions are estimated based on a number of plant emissions specified in the NOx register for 2012 [59]. Emissions of fossil carbon dioxide are based on information from energy companies that say that about 35 energy% of household waste is considered to be of fossil origin. The technology-specific calculation assumptions used in calculating the electricity generation cost are given in Table 4-22.

Table 4-22. Technology-specific calculation conditions for waste-fired, co-generation, 20 MW

Parameters	Value	Unit
Type of fuel	Waste	-
Heating value	3.1	$MWh/tonne_{fuel}$
Expected full load hours	7,500	h/year
Availability	95 %	-
Resulting full-load hours	7,125	h/year
Electric output gross	23.2	MW
Electric output net	20	MW
Electric conversion efficiency*	19 %	-
Alpha value net**	0.22	-
Alpha value gross***	0.33	-
Condensation heat-output	71	MW
RGK effect	19	MW
Total efficiency	105 %	-
NO_x emissions	40	mg NO_2/MJ_{fuel}
Sulphur emissions	0	mg S/MJ_{fuel}
CO2 emissions	35	g CO_2/MJ_{fuel}

* Electric conversion efficiency is defined as net electricity through fuel.
** The alpha net value is defined here as net electricity through net heating including flue gas condensation.
*** The alpha value gross is defined as gross electricity through condensation heat

4.7.4 Costs

Investment costs

Investment costs are based on two waste-fired co-generation plants that have been built recently:

- Filborna 75 MW_t, 18 $MW_{elec\ gross}$ – SEK 1,850 million
- Brista 2 80 MW_t, 20 $MW_{elec\ gross}$ – SEK 1,966 million

The various investments have a slightly different scope, in Filborna a storage tank is included, and at both Filborna and Burst 2 the routing of a relatively long district heating pipeline and more is included. The costs of extra investments for this has been deducted from the initial investment. The investment cost for a plant that produces 20 $MW_{elec,\ net}$ will be result in the order of SEK 108,600/$kW_{elec,\ net}$.

Note that the entire cost of investment in co-generation cases are charged to electricity generation and the comparison with clean electricity generating plants is not entirely representative. A waste-fired co-generation plant is not built as there is a heat source that provides income for the heat produced. The investment cost would therefore be spread over both products: electricity and heat. This is not the case in this report but investment costs are charged to electricity generation and heat production is then credited. Furthermore, the primary purpose of the co-generation plant is to handle waste and produce heat, not to generate electricity.

Operating and maintenance costs

Operating and maintenance costs for waste-fired co-generation plants are prepared through discussions with and comparing several different waste-fired plants.

The variable operating and maintenance costs consist in large part of the cost of taking care of the ash, chemical costs and the cost of maintenance not being performed by permanent staff. The cost amounts to approximately SEK 40/MWh fuel[28]. The fixed operating and maintenance costs amount to about 2.9% of the investment cost, or SEK 2,700/$kW_{elec,\ gross}$.

Fuel costs

The reception fee for household waste varies from area to area but will average about SEK 130/MWh.

Economic policy instruments

Household waste contains a certain amount of material that is of fossil origin, such as plastics. The total amount of carbon dioxide emitted through the combustion gases is estimated to be 35% of fossil origin. This share is included in the EU emission rights trading scheme.

Summarised costs

Costs and policy instruments for waste-fired co-generation plants are summarised in Table 4-23.

[28] Of which landfill tax on deposited slag totals about SEK 6.5/MWh fuel included. This applies to the technical calculation conditions stated in Table 4-22.

Table 4-23. Summarised costs and policy instruments for waste-fired heating plants, 20 MW

Parameters	Value	Unit
Specific investment	93,300	SEK/kW$_{elec, gross}$
Specific investment	108,600	SEK/kW$_{elec, net}$
Construction period	3	year
Depreciation period	25	year
Fixed O&M	3,140	SEK/kW$_{elec, net}$
Variable O&M	40	SEK/MWh$_{fuel}$
Fuel price	-130	SEK/MWh$_{fuel}$
Heat crediting*	-324	SEK/MWh$_{heat}$
NO_x repayment	-5.0	öre/kWh$_{elec}$
NO_x fees	3.8	öre/kWh$_{elec}$
Emission rights	3.3	öre/kWh$_{elec}$
Property tax	0.5	öre/kWh$_{elec}$

* Heat crediting is described in Chapter 3.6.2.

4.7.5 Results

Annual production, costs and the resulting electricity generation cost for waste-fired heating plants are summarised inTable 4-24 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments.

The electricity generation cost for waste-co-generation is according to the calculations negative, i.e. a source of income. Fuel costs are one reason why waste-co-generation has negative electricity generation costs; fuel costs nothing but provides an income. Heat crediting is the most significant item. The development of heat crediting is described in Chapter 3.6.2.

Table 4-24. Results for waste-fired heating plants with 6 % cost of capital

Parameters	Value	Unit
Production		
Electricity generation	143	GWh/year
Heat production	636	GWh/year
Costs		
Capital cost	126.3	öre/kWh$_{elec}$
O&M cost	64.9	öre/kWh$_{elec}$
Fuel cost	-67.7	öre/kWh$_{elec}$
Heat crediting	-144.7	öre/kWh$_{elec}$
NO_x repayment	-5.0	öre/kWh$_{elec}$
Taxes & fees	7.5	öre/kWh$_{elec}$
Results		
Electricity generation cost without policy instruments	-21	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	-19	öre/kWh$_{elec}$

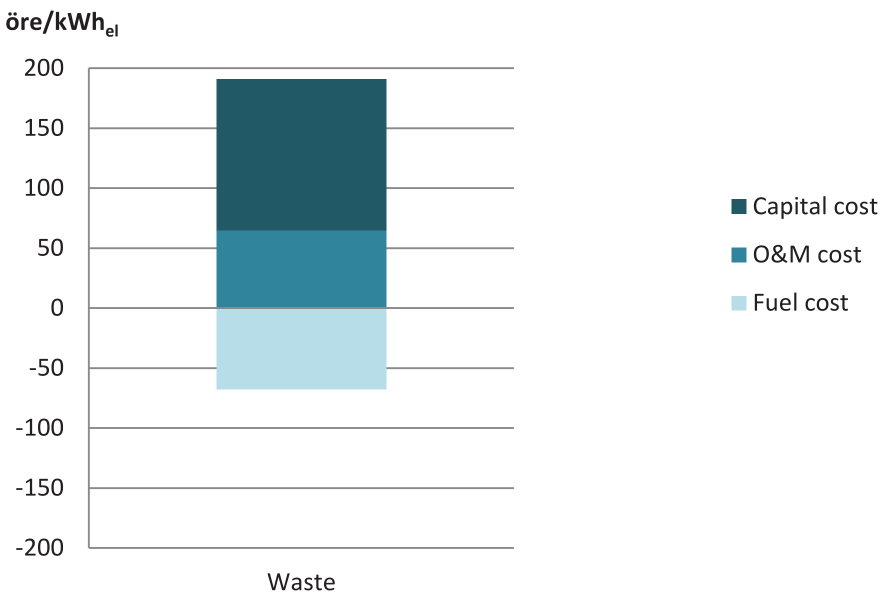

Figure 4-32. Generation costs for electricity and heating using waste-fired co-generation, excluding policy instruments and heat crediting

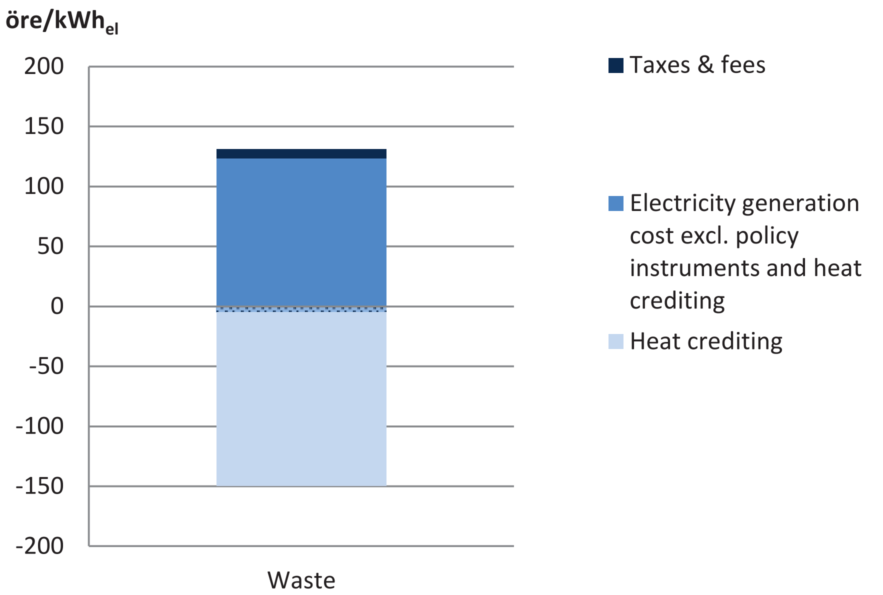

Figure 4-33. Electricity generation costs including policy instruments and heat crediting for waste-fired co-generation

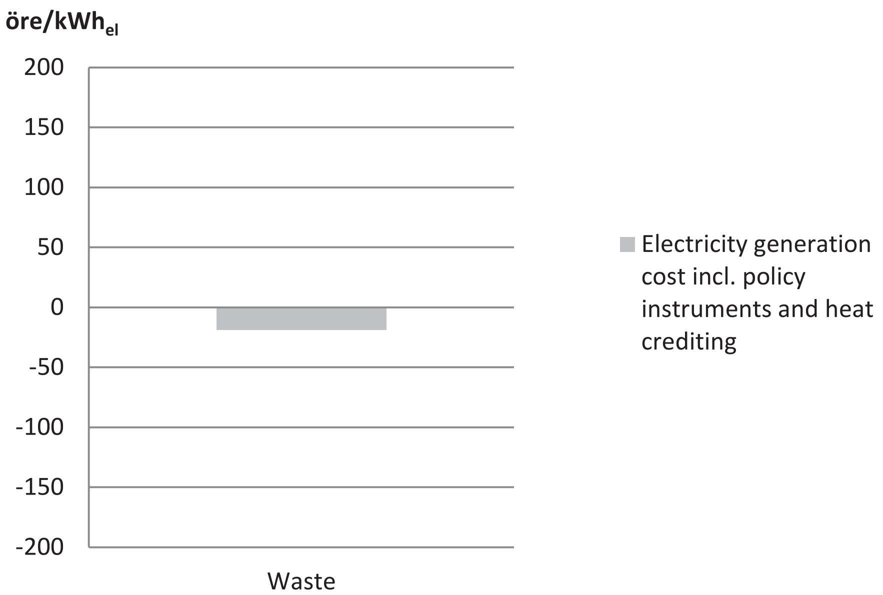

Figure 4-34. Resulting electricity generation costs including policy instruments for waste-fired co-generation

4.8 RDF co-generation

RDF (Refuse Derived Fuel) is a crushed and sorted waste fuel where a large proportion of inert materials have been separated. In many cases, sorting and burning takes place at the same location (for example, at the Händelö plant and Västerås), but the waste may also be sorted elsewhere (e.g. in Borås, Högdalen and Bollnäs) and transported to the incinerator plant as fuel. Waste pellets are imported from countries like Holland. The ash content of the fuel obviously varies depending on the sorting method but is often in the order of 10-20% by weight of dry fuel.

That the fuel is sorted implies a somewhat simpler system in terms of both fuel handling and combustion compared to using non-reprocessed household waste. Even flue gas purification may be affected depending on the extent to which the sorting is performed.

RDF can be regarded as an ordinary fuel that is procured with this in mind, i.e. the production of heat and electricity while unsorted waste is subject to a requirement for disposal. However, co-generation boilers fired by RDF tend to be used as base load boilers in the systems in which they occur. For this reason, it has been assumed that the RDF plant, from a production perspective, should be compared with the (household) waste-fired plant and given the same utilisation times as this, i.e. nominally 7,500 hours. In combination with a high calorific value for RDF, this means that the plant has a “processing” capacity of approximately 180,000 tonnes/year. In contrast to the plant for household and industrial waste (which receives and processes about 250,000 tonnes/year) which is based on fire-grate technology, it is assumed that an RDF-fired plant would be built using CFB technology. This report assumes that the plant is constructed without its own fuel preparation (fuel arrives ready-made to the plant).

4.8.1 Technology description

Sorted waste such as RDF or sorted industrial waste paper-wood and plastic can be fired in both fire-grate and fluidized bed boilers. The costly fuel preparation means that the reception charge is low, or even negative, i.e. you have to pay for the fuel. The fuel is well suited for fluidized bed technology and there are a handful of smaller plants built with bubbling fluidized bed technology, including at Borås and Lidköping. For boilers that are a little larger such as the two waste boilers at Händelö and the Högdalen 6 boiler for sorted industrial waste, circulating fluidized bed technology has been used. One advantage of CFB technology is that the last superheater can be located in the loop seal. With the placement the hottest superheaters are affected less by corrosive contaminants in the fuel. Superheaters can be made much smaller because of the better heat transfer.

Steam data for an RDF-fired boiler may vary between 420 °C/40 bar (g) and 480 °C/75 bar (g) where the lower steam data is generally obtained with BFB and the higher data with CFB technology with the loop seal superheater. The steam cycle with branch offs and preheating is similar to that for the corresponding size of a biomass fuel boiler. However, flue gas purification is expanded in an RDF boiler in that the fuel is waste classified.

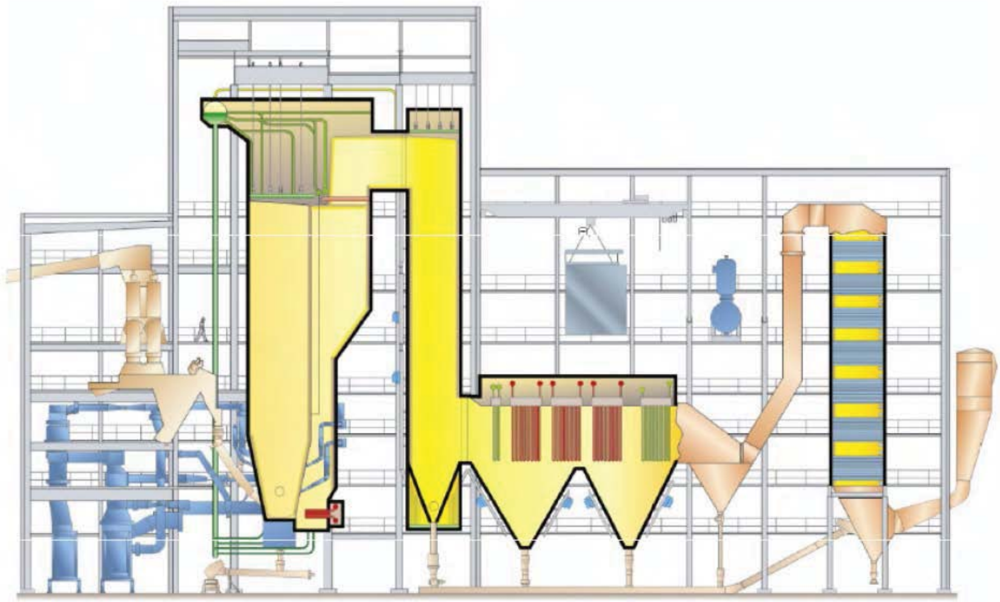

Figure 4-35. E.ON Värme's latest CFB boiler at the Händelö plant P15. Source: Foster Wheeler [61].

RT chips

Co-generation boilers for RT chips are not discussed separately in this report but here are a few comments.

Many plant owners are using recycled wood as fuel in their boilers and the justification is of course the fuel price which is lower than for biomass fuels. Sometimes the concept of non-waste classified RT chips or white RT chips is used, which can be fired in conventional biomass fuel boilers.

The waste classified RT-chips may only be burned in boilers that are classified as co-incineration/waste boilers. In many cases, RT chips represent a proportion of the fuel mixture with e.g. forest chips (slash) and possibly peat.

As for boilers that burn sorted waste, boilers for wood chips must be adapted according to the fuel which may include a higher ash content, higher content of problematic substances such as chlorine, alkali, copper, zinc, lead, etc., compared to biomass fuel.

Steam data is often slightly lowered (520-540 °C and 90-110 bar) compared to biomass fuels but not as much as for waste-fired boilers. An example of a newly constructed boiler that has been constructed to burn up to 50% RT chips is the Kraftring boiler at Örtofta. The boiler there is configured for 540 °C and 112 bar.

4.8.2 Development trends

Interest in the burning of unsorted waste varies between plant owners and depends heavily on the experiences of fluidized bed technology. The development of CFB technology with the placement of a superheater in the loop seal in combination with research into the effect of additives and the production of new materials in the superheater provides an opportunity for improved steam data. However, there is no getting away from the fact that fluidized bed technology is very sensitive to fuel quality when compared to fire-grate boilers i.e. contaminants from metal and glass easily accumulate in the sand bed and can cause problems. For bubbling fluidized beds, a lowering of the temperature has been tested at the bottom of the bed in order to minimise the risk of sintering of the sand bed, which today is also applied at some plants.

4.8.3 Technology-specific calculation conditions

The electric conversion efficiency and alpha values in Table 4-25 are an average of Mälarenergi block 6 and Nybro Transtorp. Emissions of nitrogen oxide and fossil carbon dioxide are considered to be similar to those for other waste generation, see Chapter 4.7.3. The technology-specific calculation assumptions used in calculating the electricity generation cost are given in Table 4-25.

Table 4-25. Technology-specific calculation conditions for RDF co-generation, 20 MW

Parameters	Value	Unit
Type of fuel	RDF	-
Heating value	4.2	$MWh/tonne_{fuel}$
Expected full load hours	7,500	h/year
Availability	95 %	-
Resulting full-load hours	7,125	h/year
Electric output gross	23.5	MW
Electric output net	20	MW
Electric conversion efficiency*	22 %	-
Alpha value net**	0.27	-
Alpha value gross***	0.41	-
Condensation heat-output	57	MW
RGK effect	16	MW
Total efficiency	104 %	-
NO_x emissions	40	mg NO_2/MJ_{fuel}
Sulphur emissions	0	mg S/MJ_{fuel}
CO2 emissions	35	g CO_2/MJ_{fuel}

* Electric conversion efficiency is defined as net electricity through fuel.
** The alpha net value is defined here as net electricity through net heating including flue gas condensation.
*** The alpha value gross is defined as gross electricity through condensation heat

4.8.4 Costs

Investment costs

The investment cost is estimated at about SEK 76,300/$kW_{elec,\ net}$. This is based on a number of newly constructed RDF-fired co-generation plants and some that are under construction. For one of the plants, the investment cost is higher relative to other plants in terms of size of the plant, which is largely due to the turbine also being supplied with steam from another boiler at the same plant.

Investment costs for the above-mentioned plants are listed in Figure 4-36.

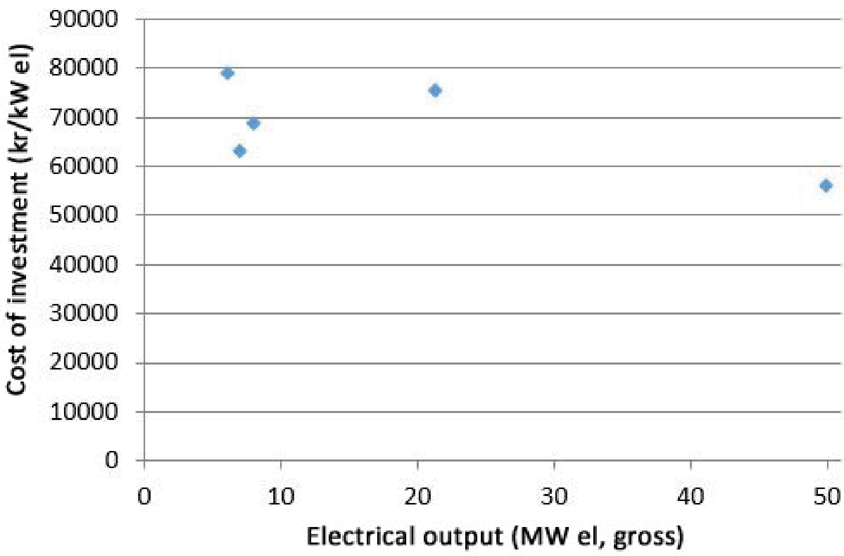

Figure 4-36. Investment cost per kW gross electricity for a number of RDF-fired co-generation plants.

Note that the entire cost of investment in co-generation cases are charged to electricity generation and the comparison with clean electricity generating plants is not entirely representative. A waste-fired co-generation plant is not built as there is a heat source that provides income for the heat produced. The investment cost would therefore be spread over both products: electricity and heat. This is not the case in this report but investment costs are charged to electricity generation and heat production is then credited. Furthermore, the primary purpose of the co-generation plant is to manage waste, not to generate electricity.

Operating and maintenance costs

Operating and maintenance costs for RDF-fired co-generation plants are based on consumption data for an RDF-fired plant.

The variable operating and maintenance costs amount to about SEK 55/MWh fuel[29]. The reason the cost is higher than for burning household waste depends largely on the fact that it is a fluidized bed boiler that provides the sand consumption and a greater amount of ash than for a fire-grate fired waste incinerator.

The fixed operating and maintenance costs amount to about 2.5 % of the investment cost, or about SEK 1,900/$kW_{elec,\ net}$.

[29] Of which landfill tax on deposited slag totals almost SEK 2/MWh fuel included. This applies to the technical calculation conditions stated in Table 4-22.

Fuel costs
Depending on the degree of reprocessing and if the fuel is reprocessed at the plant or at a remote location, the fuel cost for RDF can vary between SEK 0 and 50/MWh. A charge of SEK 25/MWh fuel is applied.

Summarised costs
Costs and policy instruments for RDF co-generation plants are summarised in Table 4-26.

Table 4-26. Summarised costs and policy instruments for RDF co-generation, 20 MW

Parameters	Value	Unit
Specific investment	65,000	SEK/$kW_{elec, gross}$
Specific investment	76,300	SEK/$kW_{elec, net}$
Construction period	2	year
Depreciation period	25	year
Fixed O&M	1,900	SEK/$kW_{elec, net}$
Variable O&M	55	SEK/MWh_{fuel}
Fuel price	25	SEK/MWh_{fuel}
Heat crediting*	-324	SEK/MWh_{heat}
NO_x repayment	-4.2	öre/kWh_{elec}
NO_x fees	3.2	öre/kWh_{elec}
Emission rights	2.8	öre/kWh_{elec}
Property tax	0.5	öre/kWh_{elec}

* Heat crediting is described in Chapter 3.6.2.

4.8.5 Results

Annual production, costs and the resulting electricity generation cost for RDF co-generation are summarised inTable 4-27 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments. RDF co-generation have a relatively high capital cost. However, the low cost of fuel along with heat crediting and long operating times means the electricity cost from an RDF-fired plant is low.

Table 4-27. Results for RDF co-generation with 6 % cost of capital

Parameters	Value	Unit
Production		
Electricity generation	143	GWh/year
Heat production	523	GWh/year
Costs		
Capital cost	86.7	öre/kWh$_{elec}$
O&M cost	51.3	öre/kWh$_{elec}$
Fuel cost	11.2	öre/kWh$_{elec}$
Heat crediting	-118.9	öre/kWh$_{elec}$
NO_x repayment	-4.2	öre/kWh$_{elec}$
Taxes & fees	6.6	öre/kWh$_{elec}$
Results		
Electricity generation cost without policy instruments	30	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	33	öre/kWh$_{elec}$

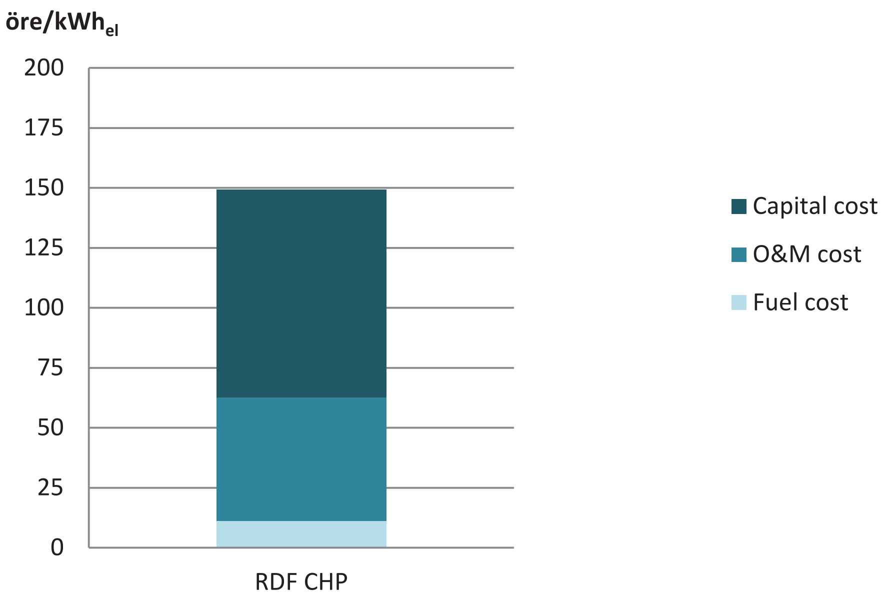

Figure 4-37. Generation costs for electricity and heating using RDF co-generation, excluding policy instruments and heat crediting

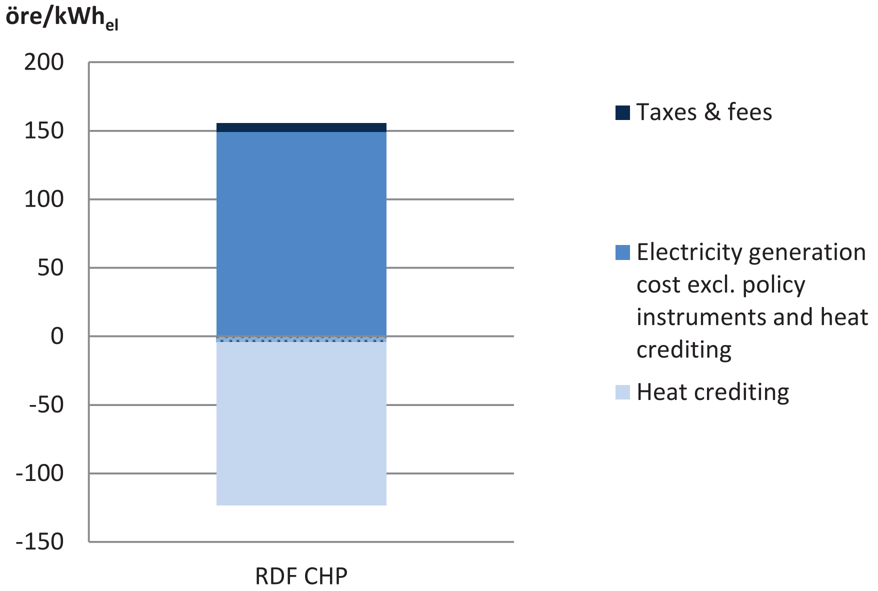

Figure 4-38. Electricity generation costs including policy instruments and heat crediting for RDF co-generation

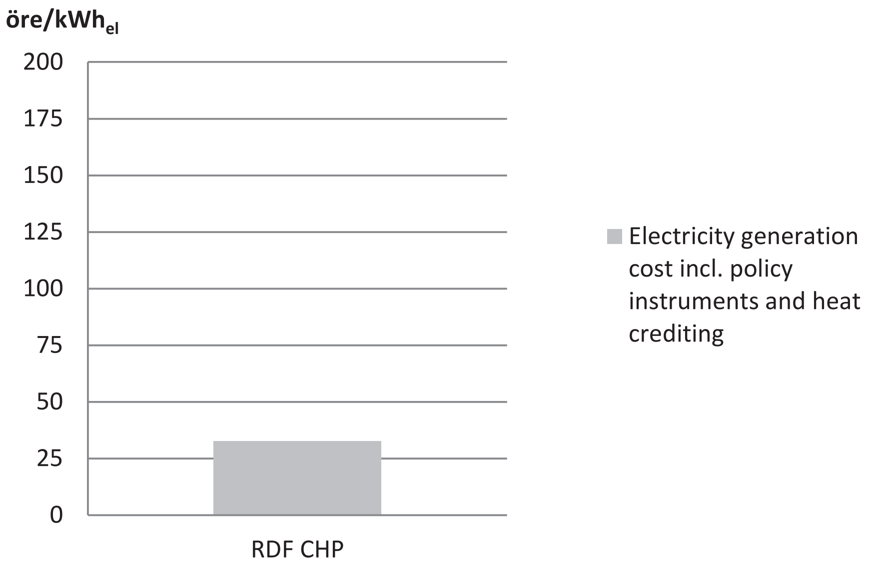

Figure 4-39. Resulting electricity generation costs including policy instruments and heat crediting for RDF co-generation

4.9 Gas engine

4.9.1 Technology description

Basic structure

For small-scale generation there are three technology options; Otto cycle engines engine, diesel engine and gas turbines. Larger Otto cycle engines for gas are usually a diesel engine converted for gas operation and the engine works entirely according to the Otto process, with relatively low compression and combustion pressure. Otto cycle engines can work with several different types of gas such as natural gas, producer gas or sewage gas and the gas is supplied to the engine at, or slightly above, atmospheric pressure and is mixed with the combustion air and then drawn into the engine via a “conventional gasifier”. The mixture is ignited by a spark from the spark plug. The only restriction is that the engine's compression ratio must be so low that the gas does not ignite spontaneously during compression in the cylinder. With combustion technical measures, such as lean-burn technology, a considerable reduction of emission levels related to NO_x and CO can be achieved using this type of engine, however, the methane slippage increases. The same type of three-way catalyst used in car engines can also be used to further reduce emission levels. Heat is produced like it is for diesel engines through the exhaust heat recovery boiler and from the engine cooling water.

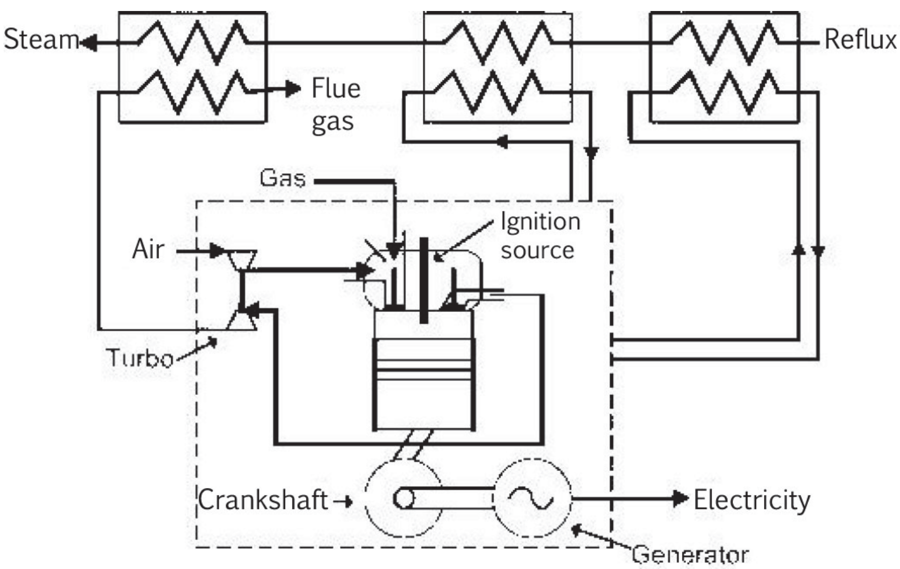

Figure 4-40. Examples of gas engine configuration from co-generation.

Diesel engines have previously been mainly used for ship propulsion. In recent decades, it has been used increasingly in power plants around the world. The reason for this is that the diesel engine has a relatively high electric conversion efficiency even in small units. Efficiency is relatively high even at partial load which is also a characteristic for the engine. Modern diesel engines can be easily adapted to run on gas, usually natural gas, but also bio-gas, etc. Heat is produced in the exhaust boiler and heat is recovered from the engine cooling water. The diesel engine has relatively high NO_x emissions, but today purification using SCR technology has been established and provides a reduction in NO_x level by 80-90%, meaning that acceptable NO_x levels can be reached.

A gas turbine consists of three parts: A compressor in which air is compressed, a combustion chamber in which heat is supplied through the fuel, such as natural gas, is combusted together with air, and a turbine in which the combustion gases expand. Most small-scale gas turbines have a single-stage centrifugal compressor. The turbine could be a single stage radial turbine or an axial turbine. The combustion chamber is of the silo model and can be adapted for natural gas and/or liquid fuel. The configuration is uniaxial, which means that the turbine drives the compressor as well as the generator directly. Small gas turbines operate at high speed which is why the generator must be connected via a switch. In order to increase the electric conversion efficiency, a regenerative gas turbine cycle can be made, which means that it is fitted with a heat exchanger (recuperator) with which the heat is taken from the combustion gases and supplied to the combustion air. Heat production is reduced by a corresponding amount. Fuel utilisation decreases slightly.

Size 100 kW$_{elec}$
In this size class, the Otto cycle engine is a common solution. It is also technically possible to use diesel engines and micro-gas turbines.

The electric conversion efficiency for an Otto cycle engine at the current size is about 33% and fuel efficiency 80-90%. The engine type produces lower emissions levels than the diesel engine and SCR levels can be further reduced.

Size 1 MW$_{el}$
In this size range, the diesel engine is a common solution. It is also technically possible to use Otto cycle engines and gas turbines.

The electric conversion efficiency for a diesel engine at the current size is about 40 % and fuel efficiency 80-90%. NO_x emissions with SCR are about 40 ppmv and CO emissions are about 90 ppmv. Unburned hydrocarbons are about 50 ppmv.

Some gas turbines are also offered in this size class. The electric conversion efficiency is about 25% and overall efficiency 80-90%.

4.9.2 Development trends

Gas engines represent a mature technology, and no major technological leap can be expected. However, the use of gas engines in contexts other than natural gas firing may be on the rise, such as the burning of bio-gas from anaerobic digestion or with bio-methane from the gasification of wood chips. This places demands on material in the gas engine and purification equipment for the gas.

4.9.3 Technology-specific calculation conditions

The production data that forms the basis for the calculations and that are listed inTable 4-28 come from a few different sizes of gas engine from the supplier Jenbacher [62]. The total efficiency is higher for the smaller gas engine which is due to the electric conversion efficiency being lower and consequently higher heat production per unit of fuel. Carbon dioxide emissions are the same as for other natural gas-fired power plants, see 4.2.3. In this study, natural gas has been selected as a fuel but upgraded bio-gas could also be used which would lead to lower tax levels. Emissions of nitrogen oxides (NO_{x}) are based on no catalytic reduction occurring. The reason for this is that plants of the size studied here are not part of the NO_x system and the financial incentive to invest in an SCR system is therefore not there.

Table 4-28. Technology-specific calculation conditions for gas engines, 0.1, and 1 MW

Parameters	0.1 MW	1 MW	Unit
Type of fuel	Natural gas	Natural gas	-
Heating value	38.9	38.9	MJ/Nm^3
Expected full load hours	5,000	5,000	h/year
Availability	95 %	95 %	-
Resulting full-load hours	4,750	4,750	h/year
Electric output gross	0.103	1.02	MW
Electric output net	0.1	1	MW
Electric conversion efficiency*	38 %	40 %	-
Alpha value net**	0.74	0.86	-
Heat output	0.14	1.17	MW
Total efficiency	89 %	86 %	-
NO_x emissions	75	75	mg NO_2/MJ_{fuel}
Sulphur emissions	0	0	mg S/MJ_{fuel}
CO2 emissions	56.8	56.8	g CO_2/MJ_{fuel}

* Electric conversion efficiency is defined as net electricity through fuel.
** The alpha net value is defined here as net electricity through net heating.

4.9.4 Costs

Investment costs

Investment costs for machine equipment observe a relatively well-defined cost curve. However, since the plants are so small in terms of output, local conditions regarding land, buildings and infrastructure will have a major impact on the cost which may vary a lot within the same output range as evidenced for example by Merše et al. which is conducting a number of gas engine based projects [63]. A summary of the investment cost data from various sources clearly shows the spread (see Figure 4-41).

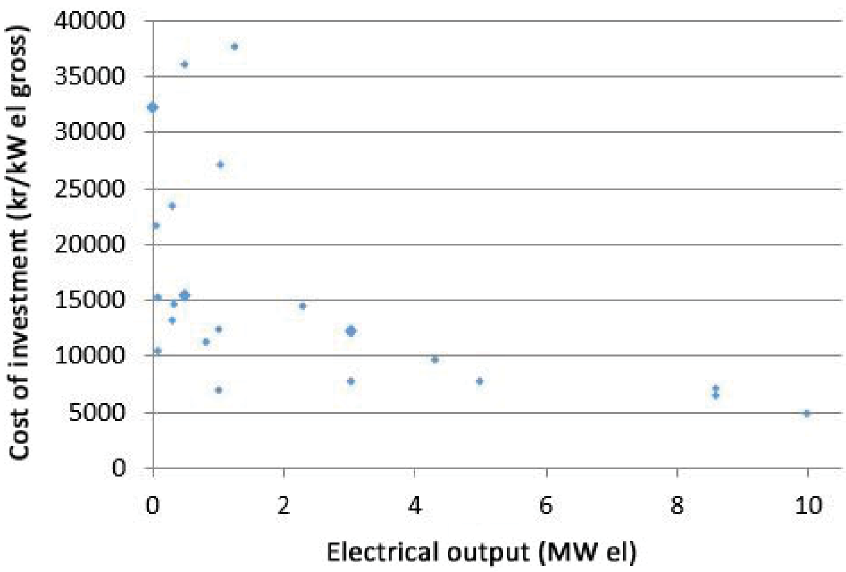

Figure 4-41. Spread of investment costs per kW gross electricity for gas engines.

The investment costs for gas engines used in the calculations are an aggregate and amount to SEK 13,500/kW$_{elec,\ gross}$ for a 100 kW gas engine and SEK 10,000/kW$_{elec,\ gross}$ ([64] and [65]) for a 1 MW gas engine.

Operating and maintenance costs

Gas engines are often maintained through service agreements, which usually have a fixed cost per installed output and a variable cost. The division between the fixed cost and variable cost varies greatly between different sources (for example, [64] and [36]). The variable cost is set at SEK 18/MWh fuel [36] which is in line with the cost quoted by an energy company. The fixed O&M costs for slightly larger gas engines are listed by the energy company at about SEK 730/kW$_{elec,\ net}$. For smaller gas engines a cost of SEK 1000/kW$_{elec,\ net}$ [36] is applied.

Fuel costs

The cost of natural gas is described in 3.2 and is set to SEK 340/MWh$_{fuel}$ for the smaller plant and SEK 320/MWh $_{fuel}$ for larger plants (see Chapter 3.2).

Economic policy instruments

Gas engines in this study are such small consumers of natural gas that they do not need to pay the nitrogen oxide charge, as incineration plants with electricity and/or heat production at less than 25 GWh are not covered by the system.

Summarised costs

Costs and policy instruments for gas engine co-generation plants are summarised in Table 4-29.

Table 4-29. Summarised costs and policy instruments for gas engines, 0.1, and 1 MW

Parameters	0.1 MW	1 MW	Unit
Specific investment	13,500	10,000	SEK/$kW_{elec,\ gross}$
Specific investment	13,900	10,200	SEK/$kW_{elec,\ net}$
Construction period	1	1	year
Depreciation period	15	15	year
Fixed O&M	1,000	730	SEK/$kW_{elec,\ net}$
Variable O&M	18	18	SEK/MWh_{elec}
Fuel price	340	320	SEK/MWh_{fuel}
Heat crediting*	-594	-499	SEK/MWh_{heat}
NO_x repayment**	0	0	öre/kWh_{elec}
NO_x fees**	0	0	öre/kWh_{elec}
Sulphur tax	0	0	öre/kWh_{elec}
Emission rights	2.7	2.6	öre/kWh_{elec}
Energy tax	4.0	3.6	öre/kWh_{elec}
CO2 tax	0.6	0.6	öre/kWh_{elec}
Property tax	0.5	0.5	öre/kWh_{elec}

* Heat crediting is described in Chapter 3.6.2.
** Combustion plants with electricity and/or heat <25 GWh are not covered by the nitrogen oxide charge

4.9.5 Results

Annual production, costs and the resulting electricity generation cost for gas engines are summarised inTable 4-30 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments. Fuel costs are greatest for a natural gas engine based co-generation plant.

Table 4-30. Results for gas engine with 6% cost of capital

Parameters	0.1 MW	1 MW	Unit
Production			
Electricity generation	0.48	4.8	GWh/year
Heat production	0.65	5.6	GWh/year
Costs			
Capital cost	30.7	22.6	öre/kWh$_{elec}$
O&M cost	25.8	19.9	öre/kWh$_{elec}$
Fuel cost	90.2	80.6	öre/kWh$_{elec}$
Heat crediting	-80.8	-58.4	öre/kWh$_{elec}$
NO_x repayment	0	0	öre/kWh$_{elec}$
Taxes & fees	7.9	7.2	öre/kWh$_{elec}$
Results			
Electricity generation cost without policy instruments	66	65	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	74	72	öre/kWh$_{elec}$

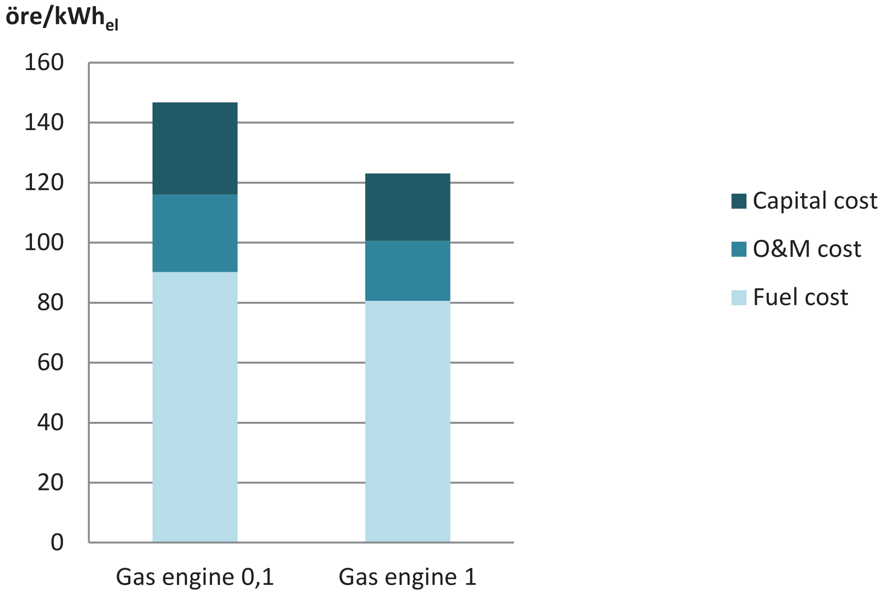

Figure 4-42. Generation costs of electricity and heat using gas engines, excluding policy instruments and heat crediting

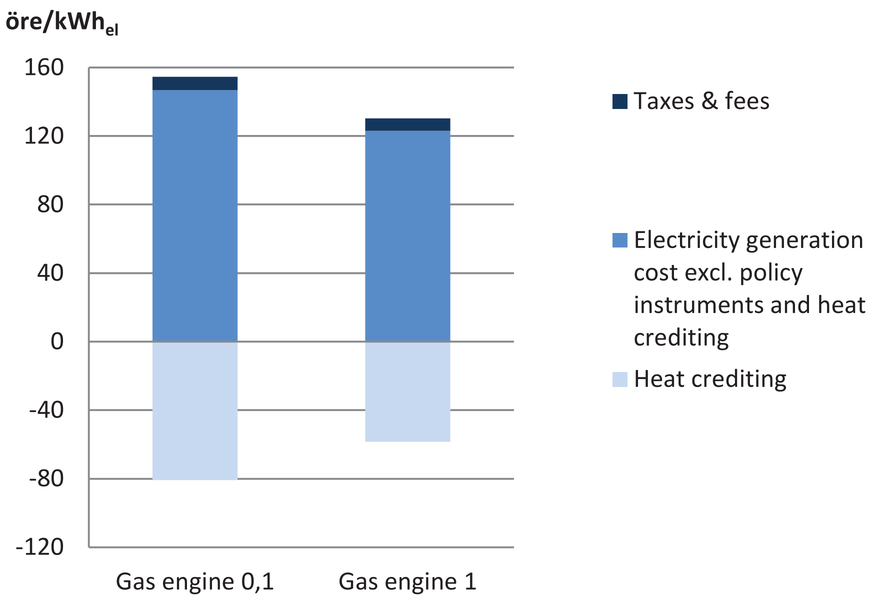

Figure 4-43. Electricity generation costs including policy instruments and heat crediting for gas engines

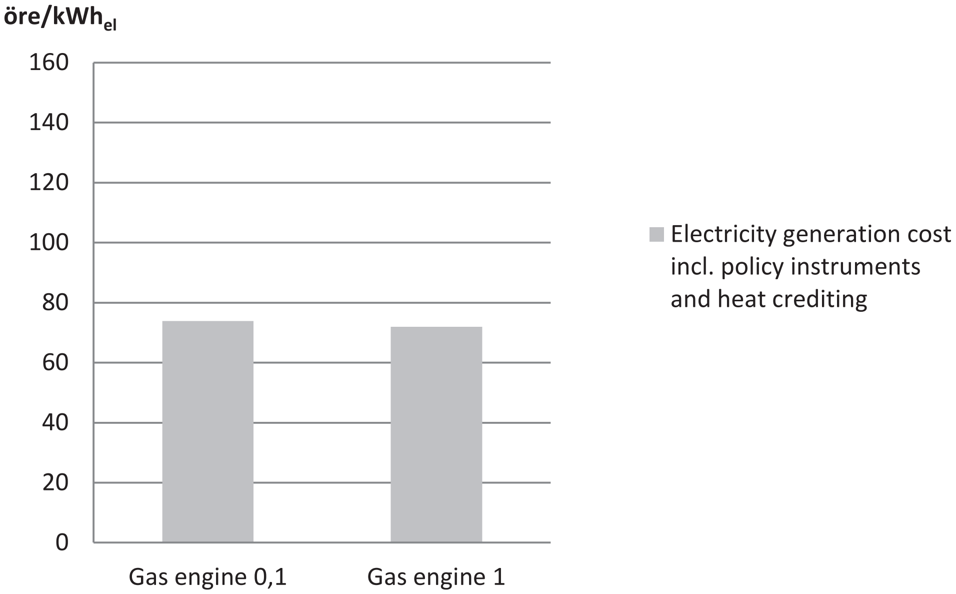

Figure 4-44. Resulting electricity generation costs including policy instruments and heat crediting for gas engines

4.10 Biomass fuel-fired co-generation plant with organic Rankine cycle (Bio-ORC)

4.10.1 Technology description

The biomass fuel-fired ORC co-generation plant has replaced the traditional water steam cycle with an ORC cycle which means that the steam cycle's water circuit has been replaced by an organic working agent.

The ORC process is based on the same principle as a conventional steam process based on water. The organic working agent is vaporised in an evaporator, gets to expand in a turbine or expander screw, and is then condensed in a condenser and pumped back to the evaporator. The ORC circuit in Bio-ORC is driven by the energy in the flue gases from a biomass fuel-fired oven via a depressurised intermediate circuit in the form of a hot oil boiler between the flue gases and ORC-circuit evaporator, see the table in Figure 4-45.

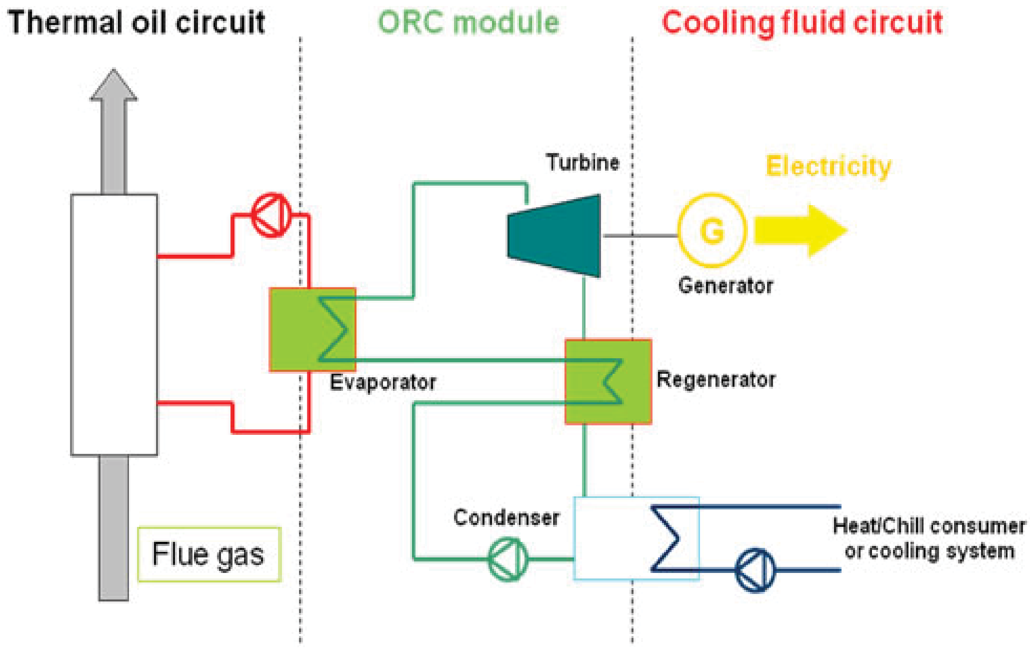

Figure 4-45. Schematic diagram of an ORC co-generation plant with hot oil circuit, ORC circuit and cooling circuit. Source: Enertime [66].

By using an organic agent with a lower evaporation temperature than water, the steam process can operate at lower temperatures without the risk of wet steam and the risk of corrosion and erosion to the turbine or expander. Other advantages of the technology are that the hot oil boiler does not need to be pressurised and is easily controlled, the ORC unit has good partial load qualities, the ORC turbine is slow moving enabling the use of a direct-drive generator which means low mechanical stress and low noise. In addition, the ORC unit is closed resulting in a low working fluid loss and no system is required that corresponds to a water treatment plant.

4.10.2 Development trends

Developments in the ORC field have been undertaken over certain periods. During the oil crisis of the 1970s, the ORC technology was seen as an interesting alternative for the generation of electricity from geothermal energy or waste heat, and a number of plants were constructed. In the 1980s, interest in the technology declined and previously active suppliers stopped being active in the area. A contributing factor was that CFC-based refrigerants, which were used as a working agent in the initial ORC plants, began to be phased out due to their ozone impact. The 2000s saw a renewed interest for ORC technology in Europe. However, interest today is mainly directed at ORC technology that is related to biomass fuel-fired plants.

According to Kjellström [67] there are over 175 biomass fuel-fired ORC systems installed in Europe, and the most established suppliers where Italian Turboden is one of the largest offer standardised plants of different sizes. This means the technology today can be considered to be commercial.

In 2013, Falbygdens Energi Sverige completed its first and so far only biomass fuel-fired ORC plant for co-generation of 2.3 MW_{elec} in Falköping. The project took as long as 3 years and the plant was supplied by Opcon Bioenergy, Saxlund, Maxxtec, Turboden and Swedish Rökgasenergi.

4.10.3 Technology-specific calculation conditions

The technology-based calculation conditions for Bio-ORC are consistently based on existing plants, and from data provided by Opcon Bioenergy.

The expected full load hours are set as it is for other co-generation technologies at 5,000 hours per year. The accessibility is set to 96%.

The electric conversion efficiency for Bio-ORC is applied at 13% with an alpha value net of 0.15.

The emission level of NO_x comes from existing plants; carbon dioxide emissions are not counted as renewable biomass fuel is fired.

Calculation conditions for Bio-ORC are summarised in Table 431.

Table 4-31. Technology-specific calculation requirements for Bio-ORC

Parameters	Value	Unit
Type of fuel	Biomass fuel	-
Heating value	2.6	$MWh/tonne_{fuel}$
Expected full load hours	5,000	h/year
Availability	96 %	-
Resulting full-load hours	4,800	h/year
Electric output gross	2.5	MW
Electric output net	2.0	MW
Electric conversion efficiency*	13 %	-
Alpha value net**	0.15	
Heat output	13	MW
Total efficiency	98 %	-
NO_x emissions	70	mg NO_2/MJ_{fuel}
Sulphur emissions	0	mg S/MJ_{fuel}
CO2 emissions	0	g CO_2/MJ_{fuel}

* Electric conversion efficiency is defined as net electricity through fuel.
** The alpha value is defined here as net electricity through net heating including flue gas condensation.

4.10.4 Costs

Investment costs

An ORC plant of 2.3 $MW_{elec,\ gross}$, which was completed in 2013 was reportedly SEK 137 million, which included everything; buildings, process equipment, electricity, water and district heating supplies, fuel management, project planning, project management etc. With a reported internal electricity consumption of 500 kW and a resulting net electricity generation of 1.8 MW_{elec} this means a specific investment at SEK 76,000/$kW_{elec,\ net}$.

Goldschmidt [68] estimates the cost of a biomass fuel ORC plant with flue gas of 2.3 MW_{elec} in 2009 at SEK 135 million based on supplier data.

Kjellström [67] indicates a specific investment for a slightly smaller ORC plant in Germany Berchtesgaden at almost SEK 55,000/kW_{elec} at the 2009 exchange rate. The plant lacks flue gas condensation and it is not known whether the cost of connecting to district heating is included, for example. The internal electricity consumption may not have to be deducted; with the corresponding internal electricity consumption for the above mentioned plant would imply a specific investment of just under SEK 70,000/kW_{elec} instead excluding flue gas condensation.

In light of the above references, a specific investment cost is applied for a 2 MW_{elec} biomass fuel ORC plant at SEK 75,000/$kW_{elec, net}$ with an economic life of 15 years.

Construction interest is based on a 1-year construction period according to experiences from constructed plants.

Operating and maintenance costs
Goldschmidt [68] estimates the O&M cost for a corresponding ORC plant at 2.5% of the investment cost, which would be comparable to a biomass fuel-fired heating plant plus a heat pump plant. Annual O&M costs are therefore set to SEK 3.75 million/year or SEK 1,875/kW_{elec}.

Fuel costs
The price of biomass fuel has been set at SEK 200/MWh_{fuel} (see Chapter 3.2).

Summarised costs
Costs and policy instruments for Bio-ORC are summarised in Table 432.

Table 4-32. Summarised costs for Bio-ORC

Parameters	Value	Unit
Specific investment	60,000	SEK/$kW_{elec, gross}$
Specific investment	75,000	SEK/$kW_{elec, net}$
Construction period	1	year
Depreciation period	15	year
O&M	1,875	SEK/$kW_{elec, net}$
Fuel price	200	SEK/MWh_{fuel}
Heat crediting*	-324	SEK/MWh_{heat}
NO_x repayment	-6.8	öre/kWh_{elec}
NO_x fees	9.7	öre/kWh_{elec}
Electricity certificate**	-190	SEK/MWh_{elec}
Property tax	0.7	öre/kWh_{elec}

* Heat crediting is described in Chapter 3.6.2.
** Electricity certificates are paid for 15 years.

4.10.5 Results

Annual production, costs and the resulting electricity generation cost for Bio-ORC are summarised in Table 4-33 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments. The capital and fuel cost is the greatest, while heat crediting is significant due to a low electric conversion efficiency. At the same time, the plant has a relatively high proportion of internal consumption, which is likely due to the operation of the district heating pumps as the plant's main purpose is to produce heat.

Table 4-33. Results for Bio-ORC with 6 % cost of capital

Parameters	Value	Unit
Production		
Electricity generation	9.6	GWh/year
Heat production	62.4	GWh/year
Costs		
Capital cost	164.7	öre/kWh_{elec}
O&M cost	39.1	öre/kWh_{elec}
Fuel cost	153.9	öre/kWh_{elec}
Heat crediting	-210.6	öre/kWh_{elec}
NO_x repayment	-6.8	öre/kWh_{elec}
Electricity certificates	-19.0	öre/kWh_{elec}
Taxes & fees	10.4	öre/kWh_{elec}
Results		
Electricity generation cost without policy instruments	147	öre/kWh_{elec}
Electricity generation cost with policy instruments	132	öre/kWh_{elec}

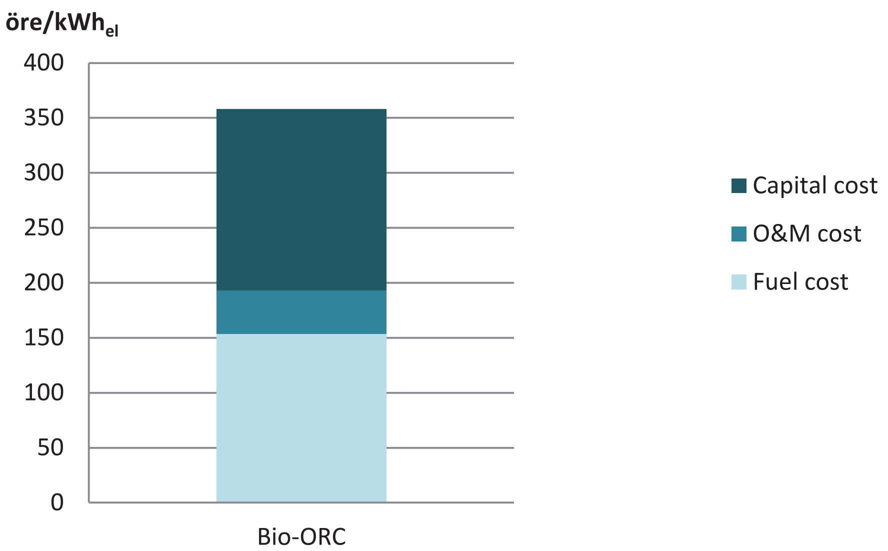

Figure 4-46. Generation costs for electricity and heat with Bio-ORC, excluding policy instruments and heat crediting

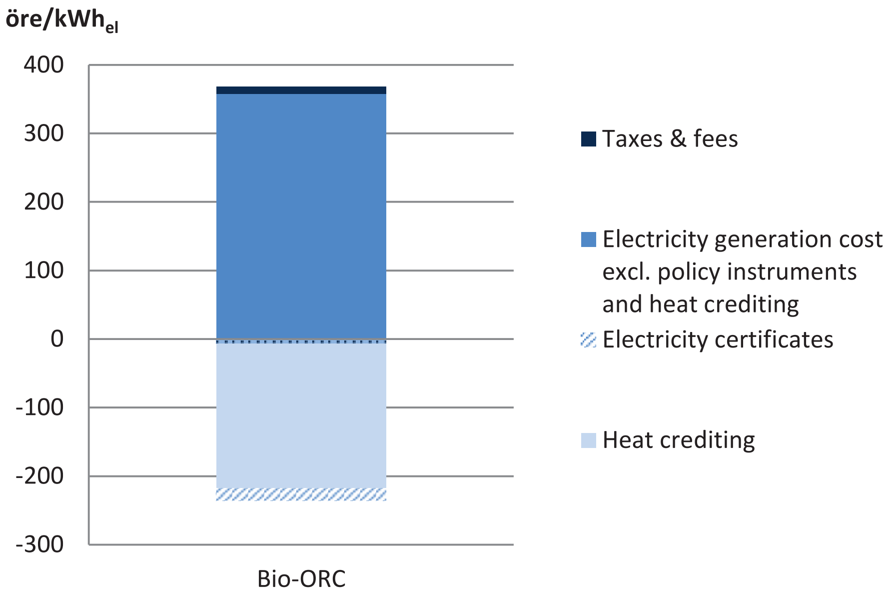

Figure 4-47. Electricity generation costs including policy instruments and heat crediting for Bio-ORC

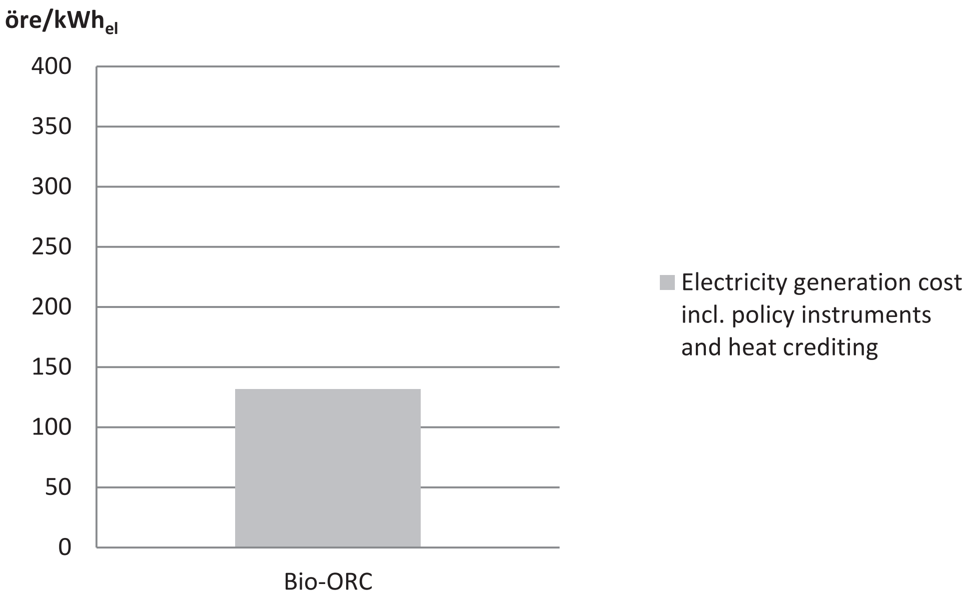

Figure 4-48. Resulting electricity generation costs including policy instruments and heat crediting for Bio-ORC

4.11 Wind power

4.11.1 Technology description

A wind turbine uses wind energy to generate electricity. The turbine rotor captures some of the energy content from the wind and converts it into electricity using a generator. The electricity is normally transferred to the mains supply via a transformer that is located either inside or outside of the wind turbine.

In the wind power industry installed output is referred to as a rule as rated output or generator output. In this study, it is equivalent to gross electrical output, $kW_{elec,\ gross}$. The user receives the amount of electricity expressed in kWh_{elec} and refers to net production.

The most significant parameter in the wind power connection is the wind speed, as higher wind speed makes it possible to generate more electricity, which makes the location of the wind turbine very important. To maximise production, the height of the wind turbine is of great importance; close to the ground, the wind speed is lower and the wind is more turbulent.

The most common type of wind power installed today is the horizontal axis model with three turbine blades, anchored on a foundation suitable for the location. There are a variety of wind turbines, designed for operation in specific environments and wind conditions, on or offshore. The turbines are classified based on the circumstances in which they are developed. Low wind power plants with large rotor surfaces for a given generator output, for example, cannot automatically be used at wind locations with high average wind speeds.

A wind power plant starts supplying output at about 3 m/s depending on the model. This output increases with wind speed and the maximum output is generally about 10-14 m/s, depending on the turbine. Maximum output is then delivered up to that wind speed as the wind turbine shuts down automatically, which is generally at about 25 m/s. Wind turbines blades can be rotated to regulate the output and maximise efficiency. A modern wind turbine produces electricity for 80-90% of the time over a year.

4.11.2 Development trends

The expansion of wind power in the world over the last two decades is shown inFigure 4-49 and that the installed output is expected to increase in the future [69]. A total installed output of 596.3 GW worldwide is expected by 2018 [70]. Within the EU expansion is expected to continue, but the rate of expansion is predicted not to increase over coming years because of a financially more uncertain market [71]. Recently published statistics show that the rate of expansion in Swedish wind power declined for the first time ever in 2013 [72], with 23% less wind power being installed compared to the previous year.

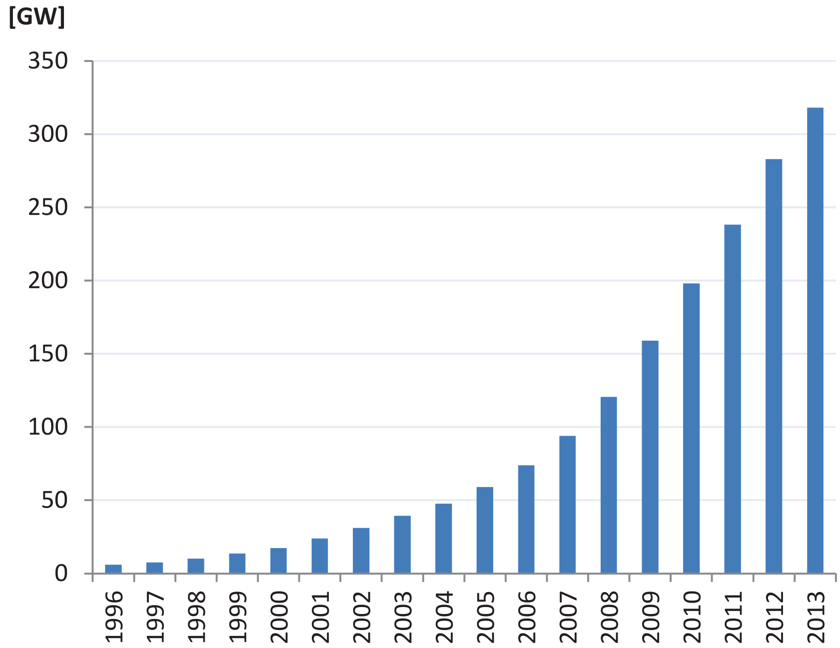

Figure 4-49. Cumulative installed wind power in the world 1996-2013 [69].

In 2013, the total wind power in Europe was estimated to produce approximately 257 TWh of electricity for a normal wind year, representing about 8% of total EU consumption [71]. In 2013, 9.9 TWh of electricity was generated from wind power in Sweden, which represents about 7% of Sweden's electricity use [73].

In an updated forecast for 2017, Svensk Vindenergi predicts an energy expansion to 7,530 MW in Sweden which would give a production figure of 17.9 TWh, corresponding to a doubling over four years [74]. The future expansion of wind power is considered to be highly dependent on the development of the electricity certificate system and is highly dependent on future energy and climate policy in Sweden and Norway.

Development of larger rotor diameters

An increasing share of Sweden's onshore projects have been built and scheduled to continue in forestry environments. However, wind in the forestry environment is affected by the forest which increases turbulence and reduces the wind's energy content compared to conditions at the same height above sea level, for example, an agricultural landscape. In order to use forest areas effectively, the trend has been towards having both higher towers, see below, and also towards wind turbines with larger rotor diameters relative to the output from the generator. The increased turbine diameter ensures a better position to take advantage of lower wind speeds.

However, a general trend has been noted whereby the wind turbines are given larger rotor diameters relative to generator output. Manufacturers have managed to optimise the plant design and control for any given average wind speed along with increased rotor diameter in a cost-effective manner. Björck [75] indicates, for example, wind turbine Näsudden 1 in Gotland, which was built in 1983 with an output of 2 MW and comprising a rotor diameter of 75 metres and a hub height of 80 metres. The Stamsåsen wind farm, recently deployed in Strömsund and Sollefteå municipalities, contains wind turbines with an output of 2.3 MW but with a rotor diameter of 113 metres and a hub height of 120 metres.

Moreover, several manufacturers have launched turbines in line with this trend. Manufacturers such as Vestas, Nordex and Gamesa have unveiled wind power plants within a range where they previously had models but with a larger rotor diameter; for example, Vestas V90 2 MW turbine (rotor diameter of 90 metres) have been developed for V100 and V110 2 MW (rotor diameter of 100 and 110 metres). It is highly likely that this trend will continue in the future, both for onshore and offshore wind power.

Development of higher tower heights

To reach a stronger wind with low turbulence, higher tower heights are being pursued. One trend is that more wind turbines where higher towers are being built. The trend is likely to be primarily economic, the increased production makes it more profitable to have higher towers.

Besides the cost of building high towers, a limiting factor in this development has previously been the difficulty of transporting tower segments to the site under the prevailing conditions offered by the Swedish road network. New technical solutions have been developed; concrete and steel combination towers, lattice towers and segmental towers are available in the market today and methods with wooden towers are at the research stage [76].

The permits for environmentally hazardous operations given in Chapter 9 of the Environmental Code which are applied for when constructing and operating wind farms, currently include as a rule plants with overall heights up to 200 metres and beyond. Wind turbines with a hub height of 145 metres and rotors of 120 metres (total height of 205 metres) are under construction in Germany [75].

Development of major generator output

A trend towards wind turbines with ever greater output is continuing, [1]. In 2010, the average installed size was below 2 MW in Sweden. 2013 saw the average output of wind turbines that were made operational during the year at 2.5 MW [74]. Today's wind turbines on the market have a much higher output. The Vestas V164 8 MW for offshore wind power has been launched, and the Enercon E126 for onshore wind reaches an installed output of 7.5 MW. The majority of the largest wind energy manufacturers market a turbine with a power of between 5 and 7.5 MW.

The development differs between offshore and onshore wind power.

a) Offshore wind power

The trend of increasing generator output is particularly true for offshore wind power. In the past, offshore wind turbines were only onshore wind turbines that had been modified, whereas today specific wind turbines have been developed for marine environments. Size and weight are not limited offshore in the same way as onshore with regard to transportation and installation which facilitated the development of larger alternator outputs.

The average output for installation offshore in 2012 was globally 4 MW. 31 companies presented in the same year the development of 38 new turbine models for installation offshore. Three quarters of these are turbines with an output of 5 MW or greater [77].

Within the EU-funded research programme Upwind [78] the potential for wind turbines with an output of 10-20 MW were studied. The programme started in 2006 and ran for five years. Offshore wind farms with a size of 10 MW were assessed in the context of the research programme to be possible in about 5 years time.

b) Onshore wind power
For onshore wind power, generator size has increased but not at the same pace and it is not certain that it will stay that way either. On the contrary, there are many people constructing with smaller generator outputs and larger rotors to ensure more full load hours.

The International Energy Agency (IEA) believes that onshore wind turbines with an output of 5 MW will be influential from 2015 to 2020 [79].

Development of de-icing systems
When wind power is established in a cold climate there is a risk of icing. When ice forms on the rotor blades it changes the aerodynamics and consequently the turbine's efficiency drops while ice throw can damage the rotor blades. According to BTM World Market Update 2012 [80], the icing of turbine blades can reduce a wind turbine's annual production by more than 20%. Technological development in this field has therefore been massive since 2010 with the development of various types of de-icing systems. The number of manufacturers who offer de-icing systems has increased and is now more than five. De-icing is achieved for commercial systems through heat in the leaves, either through a foil embedded in the leaves that turns hot when it is supplied with electricity or by hot air being directed onto the leaves.

Overall development of offshore wind power in Sweden
In Sweden at the end of 2013, there were a large number of offshore wind projects that had permits to operate but that had not been activated (approximately 2,450 MW [81]). It is most likely that more favourable economic conditions are awaited before these wind projects are implemented.

The economically weaker initial position for offshore wind power, compared to onshore wind power, is primarily due to higher investment costs and expensive maintenance. More experience leads to lower costs. There are studies that show that the opportunities for cost reduction are substantial for offshore wind power. The IEA predicts a global reduction of approximately 39% from 2011 to 2020 for projects in the North Sea. The cost reduction is expected from improvements to turbines, competition, efficiency in installation and more [79].

In Swedish waters there are opportunities to build more than 30% cheaper than in the North Sea with what is called "Inland sea method". The lack of extreme waves, winds and corrosive environments and locations with less depth brings down the cost of turbines, foundations and installation. For many locations in Swedish waters, it is fine to use the same type of wind turbines on land. The environment is often "nicer" than at a turbulent coastal location. Particular attention must be placed on analysing how components can be maintained and replaced. It should also be noted that no development takes place to turbines for Swedish conditions and that the lack of qualified experience may mean that financiers and insurers require wind turbines developed for offshore use, i.e. more expensive wind turbines developed for places like the North Sea.

4.11.3 Technology-specific calculation conditions

Four different sizes of wind farms have been studied which are reported in Table 4-34. The number of wind turbines and turbine output has been chosen to reflect the type of wind farms that are planned in a close perspective in Sweden. The offshore wind farms refer to establishments relatively close to the coast of Sweden with shallow conditions, corresponding, for example to the Kårehamn project in the Baltic Sea.

Table 4-34. Wind farms

Name	Number of turbines	Output per turbine	Total output	Onshore / Offshore
Wind Onshore 10	5	2 MW	10 MW	Onshore
Wind Onshore 150	50	3 MW	150 MW	Onshore
Wind Offshore 144	40	3.6 MW	144 MW	Offshore
Wind Offshore 600	100	6 MW	600 MW	Offshore

Calculation conditions for wind power are summarised in Table 435. Note that the effects of the farm, capacity factors, availability etc. for wind power projects vary greatly depending on location, wind conditions, turbine, etc. and it is extremely difficult to assume anything general for the various farms. Electricity generation is therefore estimated using the average equivalent full load hours (the resulting full-load hours) based on statistics and experiences in Sweden and Denmark described below.

Table 4-35. Technology-specific calculation requirements for wind power

Parameters	Wind Onshore 10	Wind Onshore 150	Wind Offshore 144	Wind Offshore 600	Unit

Resulting full-load hours*	2,900	2,900	3,700	3,700	h/year
Electric output gross	10	150	144	600	MW
Electric output net	-	-	-	-	MW

* The resulting full-load hours are equivalent full load hours.

Availability, losses and resulting full-load hours
The parameters that determine the resulting generation of electricity from a wind farm vary considerably between different projects and this mainly affects the location, wind conditions and turbine. Typical availability for onshore wind power is in the order of 98% and is between 95-98% for offshore wind depending on local conditions.

Wind farms with multiple turbines are associated with wake losses that occur when plants obscure each other from the wind. Reasonable farm outputs are generally around 95-100% depending on the layout. In addition to wake losses, wind farms are associated with grid losses in cables and transformation, losses due to dirt or ice on turbine blades, wind screw etc. and internal electricity consumption in internal systems. For a large farm, the total losses amount to about 10-15% compared to the summed maximum production for each plant based on wind power curves in undisturbed wind conditions. When designing a wind farm, acceptable loss levels are assessed in relation to cost for example for building plants further apart with longer cables as a result.

Electricity generation in this report is calculated using average equivalent full load hours (here called the resulting full-load hours) on the basis of approved plants in the electricity certificate system from 2013 to 2014 and are based on experiences from wind power projects in Sweden and Denmark. These “resulting” full load hours are calculated by dividing the specified normal annual production (MWh) by installed output (MW). On average, Swedish onshore wind projects, registered in the electricity certificate system between 2013-2014, are at 2,900 hours full load hours. The offshore wind farm at Kårehamn has approximately 3,600 full load hours under the electricity certificate system, while the average in Denmark is about 3,900 full load hours [82]. The Lillgrund wind farm and Gässlingegrundet wind farm on Vänern both have full-load hours around 3,000 hours, while the offshore wind farms Horns Rev II in Denmark enjoys over 4,500 full load hours [83]. Basically, a farm, with smaller wind turbines can have more full load hours than a farm with large wind turbines under the same wind conditions, but not necessarily a larger total amount of electricity generation. The number of full-load hours is an economic consideration and will vary from project to project.

4.11.4 Costs

Investment costs
Table 4-36 shows the investment cost and construction time used in the investigation for each wind farm. This the distribution of the investment cost is also illustrated for each installation at the wind farm. The line “other” refers to costs such as design and installation of monitoring. The construction period is

the number of years that the cost is allocated over. No reinvestment is assessed to be likely within the depreciation period.

Table 4-36. Investment costs for wind power

Parameters	**Wind Onshore 10**	**Wind Onshore 150**	**Wind Offshore 144**	**Wind Offshore 600**	**Unit**
Specific investment	12,000	12,000	25,000	23,300	SEK/kW$_{elec, gross}$
Specific investment	-	-	-	-	SEK/kW$_{elec, net}$
IP numbers*	4.1	4.1	6.8	6.3	SEK/kWh$_{,year}$
Construction period	1	2	2	2	Year
Distribution					
Wind turbines	60-65%	60-65%	30-40%	30-40%	-
Foundations	5-10%	5-10%	15-20%	15-20%	-
Electrical connection	10-15%	10-15%	20-30%	20-30%	-
Roads	5-10%	5-10%	-	-	-
Other	5-10%	5-10%	10-20%	10-20%	-

* The IP number is defined as the investment cost through annual production.

The investment costs for wind power are based on statistics from constructed plants, collective industry experience and literature (e.g. [27], [84] and [85]). Costs for existing offshore wind are more uncertain than for onshore wind as fewer projects have been undertaken. It should also be noted that the cost of wind energy varies considerably between different projects rather than between different farm sizes, particularly with respect to geographic location and connection costs. Some projects with high specific investment costs, for example, resulting from the high cost of electricity grids and infrastructure, can instead be compensated with high electricity generation when the site enjoys favourable wind conditions. The IP number, which distributes investment of annual production, is therefore a good parameter for comparing investments. Conversations with different planners acknowledge today that there are projects in the country that are building at an IP cost around SEK 4/kWh$_{,year}$.

In comparison with onshore-based plants, the generally higher investment cost for offshore wind depends in part on higher costs of the component elements, such as foundations and wiring, but also due to construction offshore being heavily dependent on long periods of low winds and small waves. The construction involves boats, cranes and equipment that are expensive to have standing idle in bad weather. It also includes the construction of a platform for the transformer. It should also be noted that the strengthening of the grid may constitute a large part of the total project cost, for example, it could lead to the strengthening of the onshore grid at a cost of 25% of the total cost of the Kårehamn project [81].

It is important to point out that the costs specified for offshore projects relate to plants relatively close to the coast of Sweden with shallow conditions, corresponding to the example project of Kårehamn in the Baltic Sea. The distance to the coast and appropriate port is of great relevance to the project's investment cost. It is likely, particularly with respect to this factor, that projects being built are primarily being located relatively close to the coast [84]. It is also worth mentioning that the establishment in the Baltic Sea is generally deemed to be economically beneficial from an international perspective [85]. Weather, with respect to wave height and storms, means that accessibility is better than, for example, than the North Sea and the proximity to the coast is large. The salinity is low, which should also affect the maintenance cost.

For wind power, the economic life has consistently been set at 20 years. For offshore plants with heavy infrastructure like foundations, internal grids and land connections, a longer period may possibly be justified as the wind turbines are a small part of the investment cost compared to onshore. For example, the electricity grids are designed for longer usage times. However, an extended depreciation period should be combined with reinvestments.

Operating and maintenance costs
The costs of operation and maintenance are estimated at SEK 140/MWh for onshore wind and SEK 180/MWh for offshore wind. Operating and maintenance costs are based, just as with the investment costs, on the collected data, literature and industry experience. The cost is a flat rate over its lifetime and includes all costs, such as scheduled and unscheduled maintenance, insurance, land lease, rural development grant and electricity transfer.

The streamlining of the maintenance work since 2010 has driven the development towards more cost-effective maintenance. However, today's wind turbine maintenance work requires both a mechanical and an electrical engineer with respect to the advanced electronics contained in today's wind turbines. Previous models only usually required one mechanical engineer which has led to a cost increase.

Economic policy instruments
Property tax for wind power is actually differentiated based on, among other things, output and estimated capacity factor. For the calculations, the same property tax has been set for all wind farms at SEK 0.004/kWh which is an estimated standard explained in Chapter 3.8.4.

Summarised costs
Costs and policy instruments for wind power are summarised in Table 437.

Table 4-37. Summarised costs for wind power

Parameters	Wind Onshore 10	Wind Onshore 150	Wind Offshore 144	Wind Offshore 600	Unit
Specific investment	12,000	12,000	25,000	23,300	SEK/kW$_{elec, gross}$
Specific investment	-	-	-	-	SEK/kW$_{elec, net}$
Construction period	1	2	2	2	year
Depreciation period	20	20	20	20	year
O&M	140	140	180	180	SEK/MWh$_{elec}$
Electricity certificate*	-190	-190	-190	-190	SEK/MWh$_{elec}$
Property tax	0.4	0.4	0.4	0.4	öre/kWh$_{elec}$

* Electricity certificates are paid for 15 years.

4.11.5 Results

Annual production, costs and the resulting electricity generation cost for wind power are summarised inTable 4-38 and inFigure 4-50 - Figure 4-52 and with a cost of capital of 6%. The results are presented both with and without economic policy instruments.

The cost of capital is by far the largest expense item for the electricity generation cost of wind power. The calculations have used a cost of capital of 6% for all power sources which is not necessarily representative of wind power. For onshore wind power it is sometimes the case, for example, that you have investors with a low demand on returns where a lower cost of capital can be justified, while offshore wind power is associated with a higher risk where a higher cost of capital may be justified. A sensitivity analysis of the cost of capital is made for both onshore and offshore wind power in Chapter 5.3.1 and the cost of capital may, for your own calculations, be changed arbitrarily in the calculation application and is described in Chapter 6.

Observe that offshore wind power in the report refers to establishments relatively close to the coast of Sweden with shallow conditions and are therefore not directly comparable to establishments far from the coast, for example, in the North Sea.

Table 4-38. Results for wind power with 6 % cost of capital

Parameters	Wind Onshore 10	Wind Onshore 150	Wind Offshore 144	Wind Offshore 600	Unit
Production					
Electricity generation	29	435	533	2,200	GWh/year
Costs					
Capital cost	36.8	37.2	61.1	56.9	öre/kWh$_{elec}$
O&M cost	14.0	14.0	18.0	18.0	öre/kWh$_{elec}$
Electricity certificates	-16.1	-16.1	-16.1	-16.1	öre/kWh$_{elec}$
Taxes & fees	0.4	0.4	0.4	0.4	öre/kWh$_{elec}$
Results					
Electricity generation cost without policy instruments	51	51	79	75	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	35	36	63	59	öre/kWh$_{elec}$

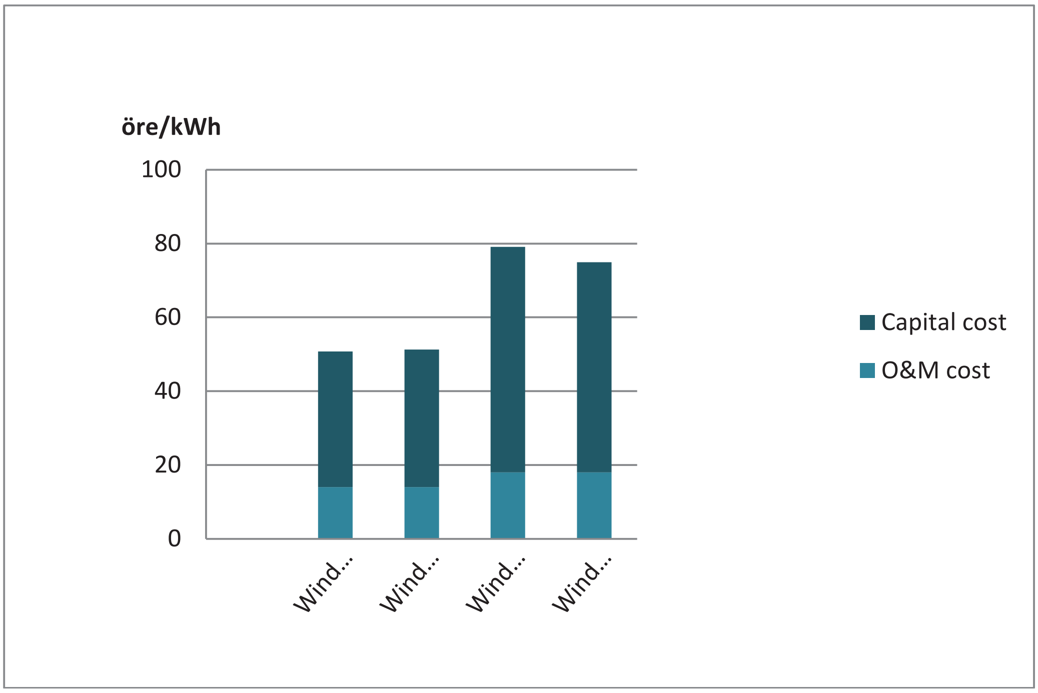

Figure 4-50. Electricity generation costs excluding policy instruments for wind power

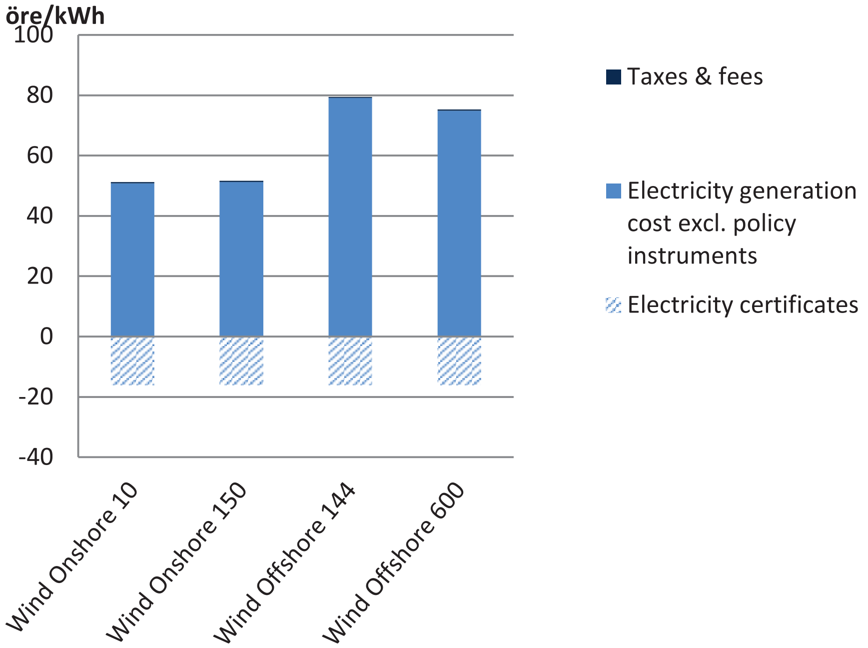

Figure 4-51. Electricity generation costs including policy instruments for wind power

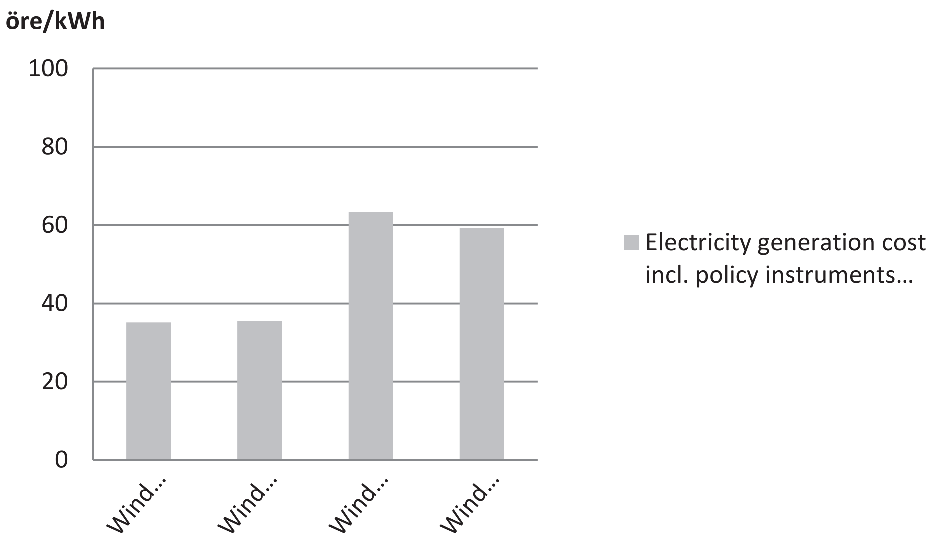

Figure 4-52. Resulting electricity generation costs including policy instruments for wind power

4.12 Hydroelectric power

4.12.1 Technology description

A hydroelectric power plant converts the energy in a watercourse to electrical power via a turbine and a generator. There is often some form of magazine/reservoir involved where running water is collected. By building a reservoir, large amounts of water can be stored; while the drop height is from a longer section of the watercourse can be collected and used in the hydroelectric power plant. From the reservoir, the water is directed via a feed line to the turbine where the water's potential energy is converted into pressure and kinetic energy. At the entrance of the inlet pipe there are cleaning grilles that prevents foreign objects from reaching the turbine, as well as gaps to close the inlet. The flowing water causes the turbine to rotate, which in turn drives a generator to generate electricity. The type of turbine used depends on site-specific conditions, although mainly vertical drop and flow is used. Examples include Kaplan and propeller turbines, Francis turbines, Pelton turbines, cross-flow turbines and other impulse turbines. After the turbine, the water is directed on through a drain back into the watercourse. The above is supplemented with switchgear and transformers for the mains grid. In addition, monitoring equipment is installed which is generally linked to a computerised management and monitoring system.

Each hydroelectric power plant is uniquely designed based on the prevailing local conditions with respect to both vertical height and water flow but also on the interaction with other plants along the same river. Some plants, usually higher up the river, are used as regulating power and run for a fraction of the year while other plants are used as base load and run as much as possible over the course of the year. The plants may vary a lot depending on their component parts and local conditions, for example, if they are power plants without long channels or tubes, or if they are power plants with high vertical drops with long waterways.

In Sweden, two different turbine types are chiefly used; the Francis and Kaplan turbines. The Francis turbine has adjustable guide vanes and fixed runner blades and is used primarily at plants with a high vertical drop or with even water flow. For lower drop heights and uneven water flow, a Kaplan turbine is used which, in addition to adjustable guide vanes, has rotatable runner blades. High efficiency is thereby achieved over a wider load range.

The amount of energy that can be converted in a hydroelectric power plant is determined primarily by the water drop and the water flow through the turbine, as well as losses in the system. Losses can be divided into loss in watercourses, turbines, generators and transformers. Modern water turbines have efficiencies in the range of 92-96%, depending on size and model.

4.12.2 Development trends

Hydroelectric power in Sweden was built over 100 years ago and today accounts for about 45% of the country's annual electricity generation. In 2012 the aggregate installed output of hydroelectric power amounted of over 16 GW and generated a staggering 78 TWh; a normal year is about 65 TWh [2].

There have been few new hydroelectric plants built in Sweden in recent years. Mainly, there have been upgrades to existing plants and new construction in already regulated watercourses. Today, and in the longer term, opportunities to exploit hydroelectric power increasingly depend on how the environmental impacts of the expansion are measured. What a higher degree of environmental adaptation may specifically involve is determined on a case-by-case basis in the context of environmental assessments. In the current situation, the majority of expandable sites are protected under the Environment Act with geographical special provisions.

4.12.3 Technology-specific calculation conditions

Hydroelectric power is used in Sweden today as both base load and regulating power depending on the power plants, their location and water supply, etc. The resulting full-load hours in this report have been set at 4,000 hours per year based on Sweden's total installed output and what is produced in a normal year according to Chapter 4.12.2.

Two output sizes were chosen to represent a small-scale (5 MW) and a large-scale (90 MW) hydroelectric plant.

Calculation conditions for hydroelectric power are summarised in Table 439.

Table 4-39. Technology-specific calculation requirements for hydroelectric power

Parameters	5 MW	90 MW	Unit
Resulting full-load hours	4,000	4,000	h/year
Electric output gross	5	90	MW
Electric output net	-	-	MW

4.12.4 Costs

All hydroelectric plants are unique in terms of size, technology and operations as they are adapted to suit the local prevailing conditions in each watercourse. To develop an overall cost for hydroelectric power is therefore very difficult. A range of costs are therefore presented on the basis of international studies, Swedish investments and information from the Swedish power companies.

Investment costs

Several international studies have compiled the costs of new hydroelectric power plants, both small and large-scale hydroelectric power plants;

- *The International Renewable Energy Agency* (IRENA) published the 2012 report, *Renewable Power Generation Costs in 2012* [86] with the costs of various renewable energy sources, including hydroelectric power.

Investment costs in Europe for large hydroelectric power plants were estimated at between SEK 7,000 and 32,000/kW, and for small hydroelectric power plants at between SEK 8,500 and 53,000/kW.

- *The World Energy Council* (WEC) presents in the report *to the World Energy Perspective* [27] of investment costs for large-scale hydroelectric power plants of between SEK 10,500 and SEK 27,500/kW and for small hydroelectric power plants of SEK 9,000 to 24,000/kW.
- The US EIA presents in the report *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* [26] an investment cost excluding construction interest for a 500 MW hydroelectric power plant with two Francis turbines at just under SEK 20,000/kW.
- The UN's nuclear agency presents a chart in the report, *Climate Change and Nuclear Power 2013* [50] with an investment cost for hydroelectric power at between just under USD 1,000 and over USD 10,000 with an average of the equivalent of SEK 30,000/kW, excluding finance costs over the construction period.

None of the above estimates can be directly applied to Swedish conditions but can function in an indicative manner and reveal how much it can vary between different investments. The studies are general and do not always identify if costs can include, for example, reservoirs, planning, water rights, etc., and what the corresponding investment would be in Sweden.

A selection of construction projects of relevance in Sweden where the investment cost are presented publicly;

- Fortum, Frykfors - New power plant of 3.8 MW and demolition of the over one hundred year old station. The investment totalled SEK 105 million and included the addition of a new power station including the demolition of the old, larger inlet tunnel at a new location and with a taintor gate, strengthening of suction pipes and the enlargement and strengthening of the outlet tunnel. Throughout the construction period, the second power station at the site remained in operation.
- Fortum, Eldforsen – New power plant of 8.5 MW with an increase in drop height of 7.7 to 10 metres and an increase in maximum flow rate from 60 to 100 m^3/s. The investment amounted to just over SEK 220 million and included a new power station at the new location with a new outlet channel, deepening of the riverbed, and a partly new dam at the power station.
- Jämtkraft, Hissmofors VI – New power station of 2x33 MW at the new location and demolition of four older units. The investment totalled SEK 1 billion and included, among other things, a new power station with new channels, intake and suction pipes, the demolition of four old units, earthworks and a partly new pond at the power station. Throughout the construction period, the second power station at the site remained in operation.

- Vattenfall, Akkats – Reconstruction of the power plant due to an extensive breakdown, two units of 75 MW each are replacing a unit of 150 MW. The investment has been estimated at SEK 1 billion and, in addition to two new turbines, includes an expansion of the machine hall, new water intake and the purging the outlet channel of rubble.

All investments are different in size, scope, location and service, while none represent a totally new construction but only new construction/conversion of power stations in already developed and regulated watercourses.

A best estimate of the specific investment excluding construction interest is based on the above studies and construction projects at SEK 20,000/kW for large hydroelectric power plants (90 MW), and SEK 25,000/kW for small hydroelectric power plants (5 MW), but with a range of between SEK 7,000 and 32 000/kW for large-scale and between SEK 8,500 and 53,000/kW for small scale. By 2011, the applied investment cost for new hydroelectric power in Sweden is based on enumerated figures from the Swedish investigations carried out in the 70s and 80s, which produced a similar cost profile [1].

Financial expenses during construction are based on a construction period of 4 years for large hydroelectric power plants and 2 years for small hydroelectric power plants.

Hydroelectric power plants have a very long service life, but parts of the plants need to be upgraded continuously at time intervals typically of 10-15 years for inspection, 25-35 years for electrical equipment and 40-60 years for heavy mechanical and electrical equipment such as turbines and generators. The calculations have therefore been based on an economic life of 40 years which is a weighted average of the technical lifetime of these parts.

Operating and maintenance costs

Just as investment costs, operating and maintenance costs vary between different plants. IRENA indicates the annual O&M costs as a percentage of the investment cost at between 2 to 2.5% for large-scale and between 1-4% for small-scale hydroelectric power plants [86]. Salvatore et al. similarly estimate O&M costs to be between 1 and 6% of the investment cost for large-scale and between 0.5 - 4% for small-scale hydroelectric power plants [27].

For a large-scale power plant of 90 MW, 2% of the investment cost of SEK 20,000/kW is equivalent to an annual cost of SEK 36 million/year. With an operating time of 4,000 hours per year, this is equivalent to an O&M cost of SEK 100/MWh, which is an empirical value for WSP for calculations regarding large-scale hydroelectric power plants. With the support of the applied O&M cost for large hydroelectric power plants of SEK 100/MWh.

Operating and maintenance costs for small hydroelectric power plants vary greatly depending on plant configuration; how many floodgates are operated manually, how much clearing of the gates of debris and ice needs to be done, and more. A power company estimates that small-scale hydroelectric power plants of the order of 1 MW, with an average annual production of around 4,000 MWh/year, have an annual O&M cost anywhere between SEK 350,000 and 700,000/year, or between SEK 87.5 and 175/MWh. O&M cost for small-scale hydroelectric power plants of 5 MW and 4,000 full load hours per year are set at SEK 125/MWh, which corresponds to 2.5% of an investment cost of SEK 25,000/kW.

Economic policy instruments
Electricity generated by hydroelectric power in new plants are entitled to electricity certificates (see Chapter 3.9).

The property tax for hydroelectric power since 2011 has been 2.8% of the assessed value, and in 2013 hydroelectric power was taxed at around 50%, which according to calculations performed by Svensk Energi, this means that the average property tax went up from the previous SEK 0.055/kWh to about SEK 0.089/kWh [18].

Summarised costs
Costs and policy instruments for hydroelectric power are summarised in Table 440.

Table 4-40. Summarised costs for hydroelectric power

Parameters	5 MW	90 MW	Unit
Specific investment	25,000	20,000	SEK/kW$_{elec, gross}$
Specific investment	-	-	SEK/kW$_{elec, net}$
Construction period	2	4	year
Depreciation period	40	40	year
O&M	125	100	SEK/MWh$_{elec}$
Electricity certificate*	-190	-190	SEK/MWh$_{elec}$
Property tax	8.9	8.9	öre/kWh$_{elec}$

* Electricity certificates are paid for 15 years

4.12.5 Results

Annual production, costs and resultant electricity generation cost for hydroelectric power summarised inTable 4-41 and in subsequent diagrams with a discount rate of 6%. The results are presented both with and without economic policy instruments.

The cost of capital is by far the largest cost for generating electricity from new hydroelectric power plants, although the most uncertain. The investment cost of SEK 20,000 and 25,000/kW is estimated from a range of between SEK 7,000 and 32,000/kW for large-scale and between SEK 8,500 and 53,000/kW for small-scale hydroelectric power plants. A sensitivity analysis of the impact of the investment cost on electricity costs is made in Chapter 5.3.3.

Hydroelectric power is burdened with the highest property tax rates among all electricity generation methods, which on average is as much as SEK 0.089/kWh [18].

Note that electricity generation costs for hydroelectric power in this report reflect newly-built hydroelectric power and not existing plants. The majority of today's hydroelectric power plants in Sweden have been in operation for a long time and consequently have much lower capital costs. At the same time as a rule, extensive rebuilding, generation increases or adverse decisions from government agencies are normally required for existing plants to be able to obtain electricity certificates.

Table 4-41. Results for hydroelectric power with 6% cost of capital

Parameters	5 MW	90 MW	Unit
Production			
Electricity generation	20	360	GWh/year
Costs			
Capital cost	43.2	35.7	öre/kWh$_{elec}$
O&M cost	12.5	10.0	öre/kWh$_{elec}$
Electricity certificates	-12.3	-12.3	öre/kWh$_{elec}$
Taxes & fees	8.9	8.9	öre/kWh$_{elec}$
Results			
Electricity generation cost <u>without</u> policy instruments	56	46	öre/kWh$_{elec}$
Electricity generation cost <u>with</u> policy instruments	52	42	öre/kWh$_{elec}$

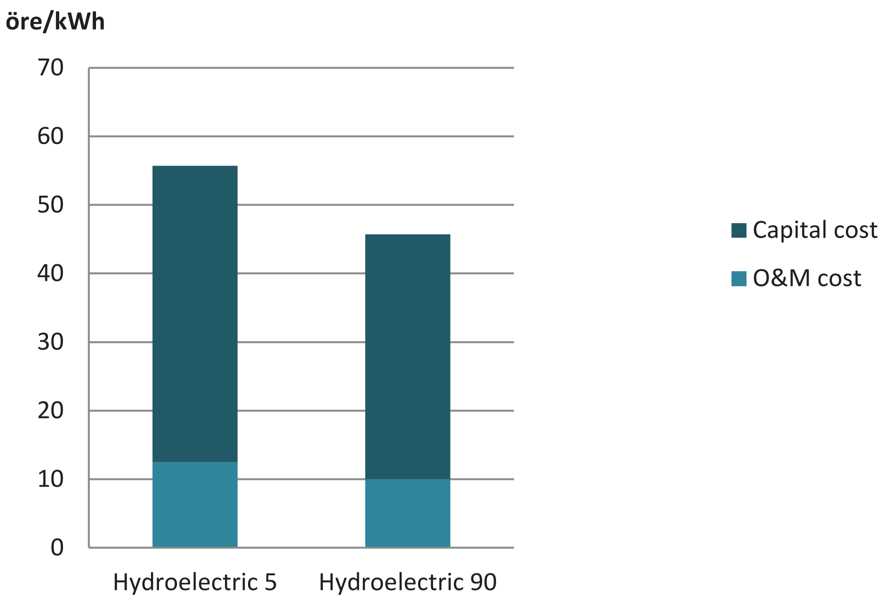

Figure 4-53. Electricity generation costs excluding policy instruments for hydroelectric power

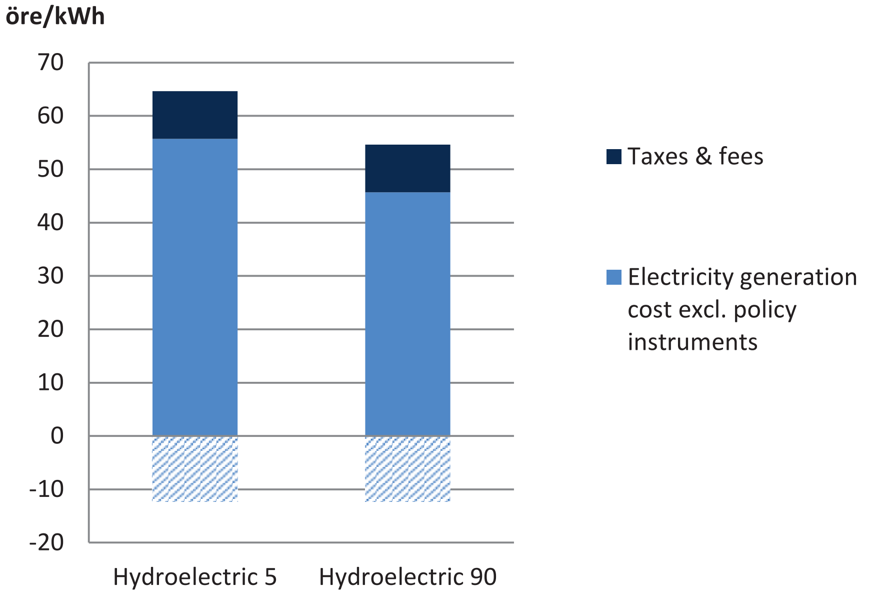

Figure 4-54. Electricity generation costs including policy instruments for hydroelectric power

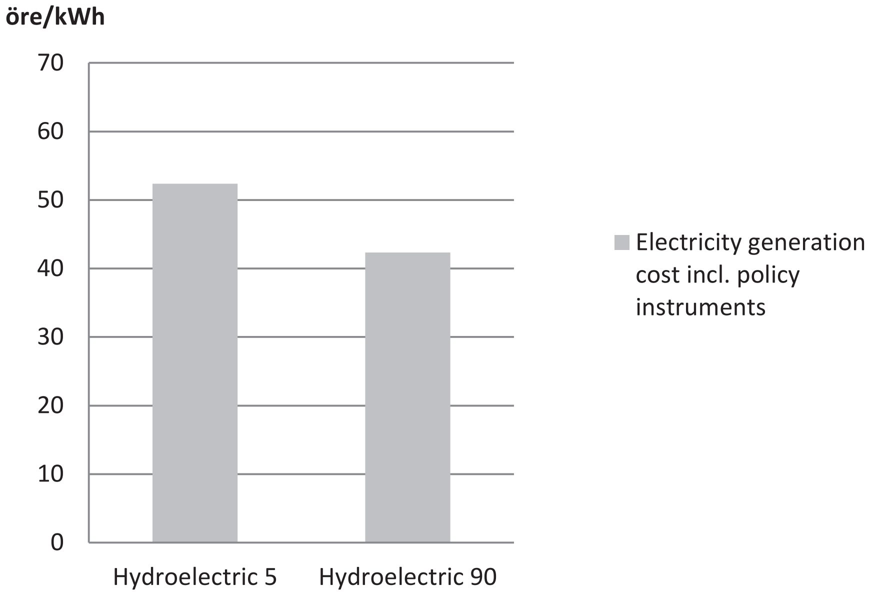

Figure 4-55. Resulting electricity generation costs including policy instruments for hydroelectric power

4.13 Photovoltaics

4.13.1 Technology description

A photovoltaic system converts solar energy into electric power and is converted from direct current to alternating current via an inverter. The material in photovoltaics include semiconductors that capture solar radiation photons and convert them into electricity. When sunlight from the right wavelength illuminates a doped semiconductor, the electrons from the outer valence band are excited up to the conduction band. This means an electric voltage is created and DC power is obtained.

> Installed output is termed as "kW peak output", "kW_t" in the solar power industry. In this study kW_t is equivalent to $kW_{gross.}$ The amount of electricity delivered to the user is often expressed in the term "kWh

The most common semiconductor material used today is crystalline silicon and photovoltaics based on this item are called first-generation photovoltaics. Second generation photovoltaics are thin-film photovoltaics composed of several thin layers of semiconductor material such as amorphous silicon or other materials such as cadmium telluride. Thin film photovoltaics can be flexible and pliable, but have a lower efficiency.

A photovoltaic system consists of a number of photovoltaic modules (a photovoltaic module is a frame with a number of series-connected photovoltaics mounted), an inverter, mounting system and peripheral equipment such as circuit breakers, electricity meters and wiring. In the current situation, the majority of photovoltaic systems installed on existing property roofs or façades are connected to the grid on the property side of the electricity meter. This is to ensure that self-generated electricity can replace purchased electricity and thereby create the greatest economic value to the plant owner compared to selling all the electricity. Any surplus that arises is fed into the network owner's power grid.

Depending on the choice of modules, inverter and other system components, a photovoltaic plant today converts about 12% of the radiated energy into useful electricity ("net electricity"). Solar electricity generation is proportional to solar radiation. You generate the most on a clear summer day while on an overcast winter's day you barely generate anything at all. This means that a photovoltaic plant produces the most during March to October, seeFigure 4-56 [87]. The assumptions that the authors of the study [87] have made are 12% system losses and a fixed mounted system without sun tracker over an average year in terms of solar radiation.

The efficiency of a photovoltaic module is calculated by measuring the effect on the STC (Standard Test Conditions) corresponding to a simulated irradiation of 1,000 $W/m^{2,}$ wherein the radiation source is at a right angle to the module, with a photovoltaic temperature of 25°C and a spectrum corresponding to an "air mass" of 1.5. The modules that are now being sold (2014) have efficiencies for STC of about 15%.

Installed output is the number of photovoltaic modules multiplied by the photovoltaic module's rated output, which is defined for STC, here called gross generation. The yield from a photovoltaic plant is usually given in kWh/kW, where the output energy is measured after the inverter or transformer, which provides what here is referred to as the net generation of electricity.

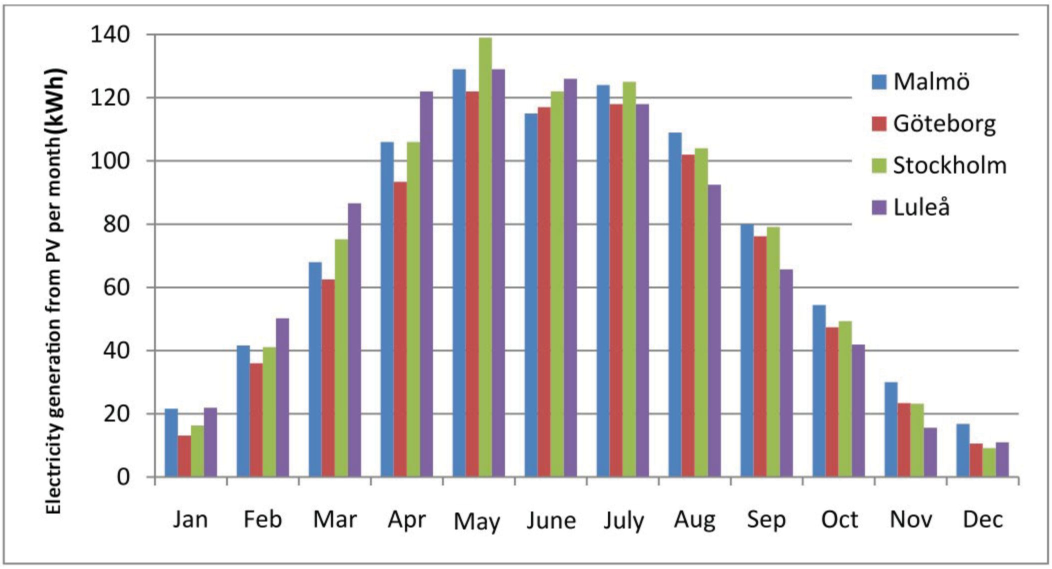

Figure 4-56. Estimated solar power generation in kWh_{net} per month for a 1 kW_{gross} photovoltaic system, when placed directly towards the south and with optimum slope of the site concerned [87].

Experience shows that the annual net production is approximately 800-1,100 $kWh/kW_{installed\ electrical\ output}$ for a Swedish system that is oriented due south, with a slope of about 30-50° and that is not shaded at any point during the day. Solar radiation per year and consequently solar power generation may vary by approximately ± 10% compared to an average year. Actual production values may differ from the estimated values due to several other reasons such as efficiency of inverters, degree of shading and fouling, how well ventilated the modules are, as well as time with snow cover.

Sun trackers are estimated by various suppliers to increase the annual electricity generation by about 30-40% in the southern half of Sweden. In northern Sweden, the increase is larger according to theoretical calculations [88].

Solar cell efficiency has dropped over the years. Module manufacturers usually provide an output guarantee that the modules will provide at least 80% of rated output after 20-25 years. The rate of decline varies between photovoltaics but the median is about 0.2% per year [89], i.e. after 30 years of service life a plant is expected to produce 94% of the installed power. The life of photovoltaics is expected to be (at least) 30 years and this longevity was used, among other things, for recently made cost estimates for solar electricity by Stridh et al [90].

Electricity generation losses in the system occur, for example, in inverters, AC and DC circuit breakers and wiring, and are estimated to be a maximum of about 10% [91]. Electricity generation can also decrease as a result of external factors such as snow, dirt, elevated temperatures in the photovoltaics etc. These losses are difficult to estimate in general as they depend on the amount of snow, the angle of photovoltaic modules, location and so on. For example, radiation due to dirt can be anywhere from 1 to 8% [92].

4.13.2 Development trends

Photovoltaics is an area experiencing rapid progress. The electric conversion efficiency for photovoltaics will grow relatively rapidly, while the cost of the modules drops. Figure 4-57 shows the trend for how efficiency has been developed for the best research photovoltaics. The efficiency of a finished module will always be lower than for each individual photovoltaic module. Many of the silicon-based photovoltaic modules sold have an efficiency of 15 to 15.5%, but there are already players on the market that deliver silicon-based photovoltaic modules with over 20% efficiency [93].

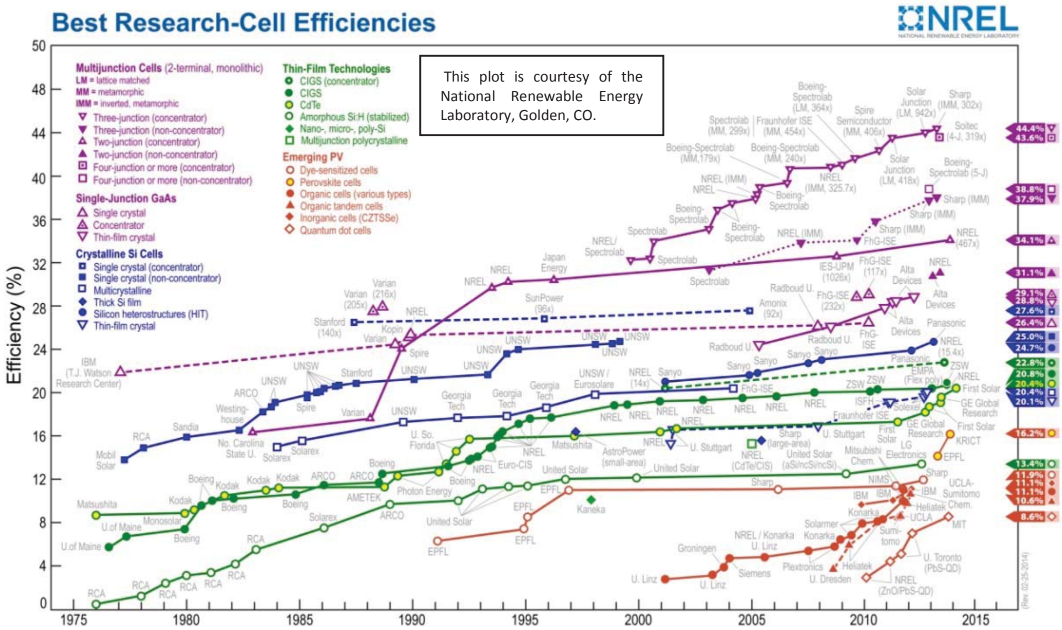

Figure 4-57. Graph showing how the efficiency of photovoltaics has developed since 1975. Source: National Renewable Energy Laboratory, Golden, CO [94].

The graph shows the peak readings for individual photovoltaics. Photovoltaic modules in commercial production always have a lower efficiency.

There are physical limits to how high efficiency can be for a photovoltaic. As the band gap size sets a limit to how large the output can be for a photovoltaic of a given material. Silicon has band gaps of 1.11 eV, which corresponds to photons with wavelengths of 1.12 microns and less. Photons with lower energy content (longer wavelength) will not excite electrons, and photons with higher energy content will still only produce 1.11 eV. This gives a maximum theoretical limit of efficiency, which can be raised if various layers of semiconductors are used, which can take up different parts of the sunlight [95].

The investment cost for a silicon-based turnkey systems has dropped from about SEK 60,000/kW$_{elec,\ gross}$ to about SEK 16,000/kW$_{elec,\ gross}$ 2010-2013 for small-scale grid-connected plants (see trend in Figure 4-58). Larger plants have also dropped significantly in price. Two large ground mounted photovoltaic systems installed by an energy company in 2013 had, for example, investment costs of SEK 11,500/kW$_{elec,\ gross.}$

The investment cost for photovoltaic modules is now so low that the trend in Europe is not to build sun-tracking systems as it is more cost effective to add more photovoltaic modules.

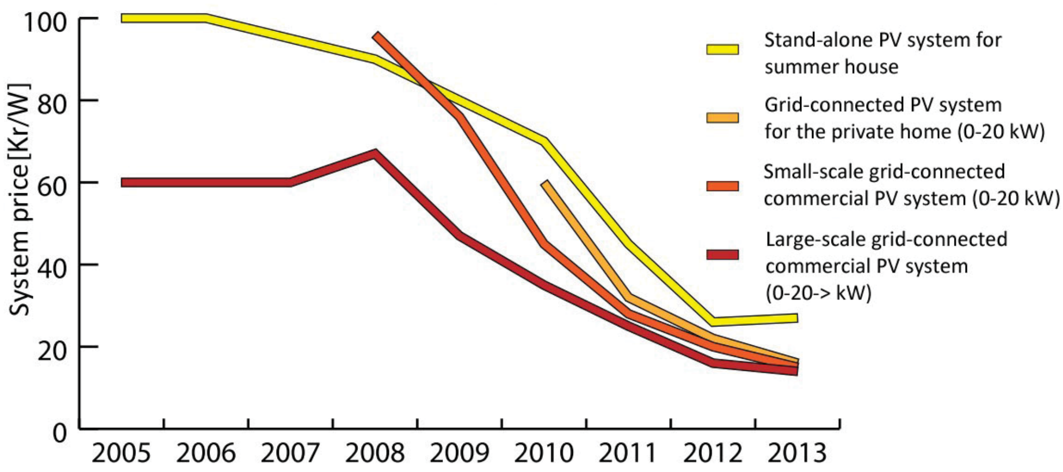

Figure 4-58. System costs for development from 2005 to 2013 SEK/Welec$_{gross}$ [96].

To date, the cost reduction for photovoltaic modules has been strongly linked to the number of installed systems, see Figure 4-59. Over the period 2013-2017, a decrease in generation from the best Chinese photovoltaic modules is expected at 19% [88]. The cost of the system is therefore expected to decline at a slower pace over the next few years than was the case until 2014.

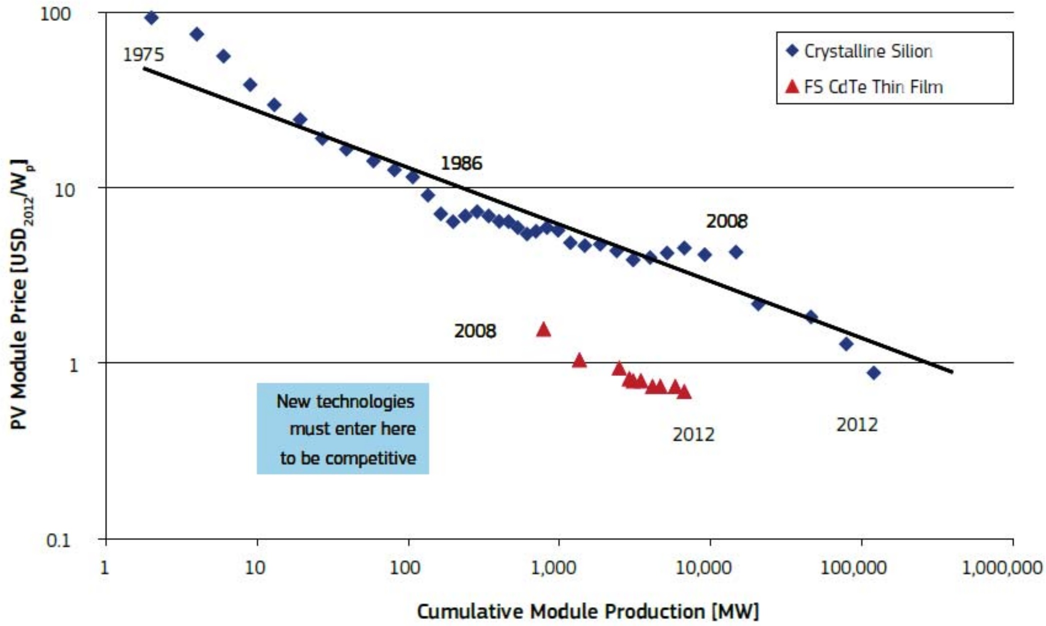

Figure 4-59. Correlation between the cost of photovoltaic modules and the cumulative module production from 1975 to 2012 [97].

The rate of installations for solar-based electricity in Sweden is increasing greatly from year to year, see Figure 4-60.

The installed power in Sweden at the end of 2013 was 43.1 MW, of which 34 MW was grid connected and generation was estimated to be around 30 GWh. This compares with Germany which produced about 30 TWh of solar electricity [98] in 2013.

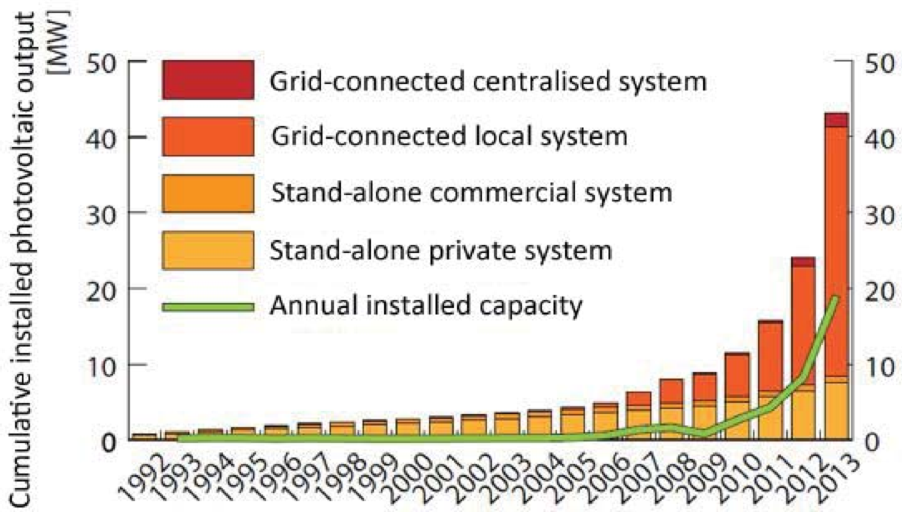

Figure 4-60. Cumulative installed photovoltaic output and annual installed capacity in Sweden from 1992 to 2013 [96].

For conventional silicon technology, development is primarily focused on reducing material quantities and thereby the price per installed electrical output. In thin-film technology, research and development is ongoing in several parallel options: CIS, CIGS, CdTe, Graetzel cells and others, where the letters stand for the substance the light absorbing layer in the cell consists of[30]. Great progress is being made in several areas and thin film technology is being demonstrated on a large scale in many locations. The big problem is how to develop an efficient industrial production process. The goal then is that thin film photovoltaics can be manufactured at low cost, with a light weight and allow for easy installation. Thin film photovoltaics can, for example, be laid on plastic mats and rolled out on roof surfaces without glass substrates and metal frames. So far, however, thin film modules are not competitive compared to silicon-based photovoltaic modules in terms of production per kWh [88]. In 2013, silicon-based photovoltaics had 91% of the world market, an increase from 89% in 2012 [99]. Silicon-based photovoltaics dominate the market within the foreseeable future. In addition to manufacturing costs, efficiency, degradation and lifetime are important parameters which all are to the benefit of silicon-based photovoltaics compared to thin-film technologies in terms of generation cost per kWh.

Thin film photovoltaics are now considered to be a standard method [100] but in the current situation it is difficult to compete on price with silicon-based photovoltaics. At the Ångström Solar Centre at Uppsala, research is underway especially on thin-film cells of the CIGS type. A company whose purpose is to manufacture these photovoltaics industrially, Solibro, was formed to market the technology that was developed at the centre. This company was sold to the German company Q-Cells and has recently been acquired by the Hanergy Group. Solibro's production plant is located in Thalheim in Germany but the development department remains in Uppsala. The efficiency of the panels can reach up to 13.4% [101] and the cost of a simple façade installation is estimated to be about SEK 25,000/kW$_{elec}$ for a larger plant in accordance with data from one of the leading suppliers of photovoltaic modules.

Another development path is known as multi-junction photovoltaics (multi-layer photovoltaics); photovoltaics composed of many layers of different materials together covering large parts of the solar spectrum. These photovoltaics can achieve extremely high efficiencies, about 45% have been measured in the lab. The costs are very high with space industry as the main target group [87].

The system side has seen a growing trend in the use of so-called building-integrated photovoltaics. These photovoltaics have more functions than electricity generation, such as sun screens or that represent part of the building's envelope. This way you can allocate costs over several commodities, while integration in the architecture can be made more appealing. Building-integrated photovoltaics can be integrated with new and existing buildings without any significant acceptance problems. They also take up no land space when installed on buildings. One example is Frodeparken in Uppsala, where the slightly curved surface is covered by 1,800 thin film photovoltaic modules of

[30] C = copper, In = indium, G = gallium S = selenium or sulphur, Cd = cadmium, Te = tellurium

the CIGS model with an installed electrical output of 100 kW and an expected production of 700 kWh/kW year [102].

Another trend is to develop appropriate technology for giant plants that could be constructed in deserts. This is currently relevant mainly in the USA, China, the Middle East and Australia. There are also plans to construct massive plants in Algeria. Today the largest solar fields are found mainly in Germany. In sunny areas, mainly desert-like areas, thermal solar power generation may also be appropriate. This method is based on a liquid that is evaporated by solar energy and the steam that is generated drives a turbine. Thermal solar power requires high direct solar radiation and can not absorb the diffuse solar radiation as well as the photovoltaics. This method will probably not be able break through as a genuine alternative in Sweden. The technology has had difficulty making a major breakthrough, due to higher generation costs per kWh compared to silicon-based modules [89].

Another area of study is to simultaneously generate electricity and heat from photovoltaic systems, known as hybrid systems. Sweden is relatively advanced in terms of research, with two companies that have begun to market and sell products for this application. The electric conversion efficiency of a hybrid system supplied by one of the companies is around 10% and the thermal efficiency is about 40%, see in particular [103]. Härnösand Energi och Miljö is one of the companies that has invested in hybrid technology, their plant is 200 m^2 and provides about 14 MWh of electricity and 54 MWh of heat annually [104].

4.13.3 Technology-specific calculation conditions

Three types of installations are studied:

- 5 $kW_{elec,\ gross}$ on roofs for residential dwellings with optimal slope and no shading
- 50 $kW_{elec,\ gross}$ on a frame on an industrial roof with optimal slope and no shading
- 1 $MW_{elec,\ gross}$ on a frame on the ground with optimal slope and no shading

The technology-specific calculation assumptions are not based on specific sites but have been prepared through contact with suppliers, plant owners and from data in research papers. System losses (from the photovoltaic after the inverter) are considered to be 1% point lower for the larger establishments (50 kW and 1 MW) which largely depends on the efficiency of the inverter, which is slightly higher for the two larger systems. The production is also assumed to decrease by 2% year on year due to dirt, snow cover etc. For modules with a low angle (< about 30°) and where there is a lot of snow, this share can increase. An availability of 100% may seem high but is in line with what a number of different suppliers and plant owners specify, based on experience. The number of full load hours is approximate and is estimated based on the annual production from existing systems relative to peak output systems. The production depends on where in the country the plant is located.

The technical calculation conditions for photovoltaic systems are presented in Table 4-42.

Table 4-42. Technology-specific calculation conditions for photovoltaic power plants; 5 kW, 50 kW and 1 MW

Parameters	5 kW	50 kW	1 MW	Unit
Resulting full-load hours*	960	970	970	h/year
Electric output gross	0.005	0.05	1	MW
Electric output net	-	-	-	MW

* These full-load hours are equivalent to the yield in kWh_{net} per kW installed power

4.13.4 Costs

Investment costs

The investment cost for a photovoltaic cell system depends on many different factors, such as where the photovoltaic modules are installed (roof, ground or wall), the module efficiency and if they are purchased from a company or an individual. For a private individual, VAT is added to the price.

The investment costs for systems of 5 and 50 kW have been set at 16,000/kW of installed electrical output for residential systems and 14,000/kW of installed electrical output for a 50 kW plant on the roof [96]. The cost of 1 MW farm which is built on a frame on the ground has been estimated based on data from one of the leading suppliers of photovoltaic modules and totals SEK 10,000/kW per installed power input. Note that the range of investment costs for actual installations can vary greatly; according to a study conducted in 2013 by Stridh et al. [90] the costs range is between SEK 11,000 and 22,000/kW for a plant of 10 kW and from SEK 14,000 and 30,000/kW for a plant of 1-5 kW.

In addition to the basic investment, a reinvestment after 15 years when the inverter is to be replaced is included. The cost of the inverter is based on data from one of the leading suppliers of photovoltaic modules and indicated for each instance in Table 4-43.

Installation of solar panels is considered to be a relatively risk-free project and the cost of capital can be set at between 3-5% [100]. This applies especially for house based system where the mortgage rate minus tax relief should be used. In order to provide a relevant comparison with the other power sources in this report, the same cost of capital, 6%, has been applied to all power sources. However, in the calculation application described in Chapter 6, the cost of capital can be adjusted.

Operating and maintenance costs

Operating and maintenance costs are generally very low for a photovoltaic plant as there are no moving parts in fixed systems. Larger plants are expected to have an annual inspection and the time for this is estimated to be 1 hour per 7 kW installed output each year [105]. Larger systems can include software and hardware for the plant owner in order to obtain daily generation reports, which means that any problems are detected in good time. Halmstad Municipality has installed a number of photovoltaic plants from 2010 onwards and states that they to date they have not had any problems with the plants [106]. This is verified by the company Euronom, that specifies that over the 10 years they been in business, maintenance has been necessary at 2 of the 100 plants [107]. For the onshore-based plant, SEK 10/kW of electricity has been added to cover the cost of the land lease.

The photovoltaic system may be vulnerable to theft of individual parts which could affect the cost of insurance, although this potential cost has not taken this into account.

Economic policy instruments
In 2014, an investment of 35% of the total investment can be applied for from the Swedish Energy Agency [108] for plants of 5 and 50 kW. In addition to this, electricity certificates are obtained for all electricity sales for larger plants. For the smaller plant, it is assumed that 50% of the electricity will be supplied to the grid and therefore receive electricity certificates.

If the investment is utilised, a home owner can be granted a deduction for renovation, maintenance and improvement for the installation work which amounts to 50% of the cost of labour.

The government has presented a proposal that smaller plants (hedging level maximum of 100 A and a maximum deduction of 30,000 kWh/year) will receive SEK 0.60/kWh electricity that is sold to the grid [109], however, this potential source of income is not taken into account as the proposal has not yet been adopted.

The onshore based plants are subject to property tax.

Summarised costs
Costs and policy instruments for photovoltaics are summarised in Table 4-43.

Table 4-43. Summarised costs for turnkey photovoltaic systems.

Parameters	5 kW	50 kW	1 MW	Unit
Specific investment	16,000	14,000	10,000	SEK/kW$_{elec, gross}$
Specific investment	-	-	-	SEK/kW$_{elec, net}$
Construction period	<<1	<1	<1	year
VAT	25 %	0 %	0 %	
Depreciation period	25	25	25	year
O&M	0	80	90	SEK/kW$_{elec}$
Reinvestment	0.009	0.07	0.97	MSEK (excluding VAT)
Time between initial and reinvestment	15	15	15	year
Investment support	35	35	0	% of investment
Electricity certificate*	-190**	-190	-190	SEK/MWh$_{elec}$
Property tax	0	0	0.5	öre/kWh$_{elec}$

* Electricity certificates are paid for 15 years
** The electricity certificate is paid for 50 % of the produced output

4.13.5 Results

Annual production, costs and the resulting electricity generation cost for photovoltaics are summarised in Table 4-44 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments.

Table 4-44. Results for photovoltaics with 6% cost of capital

Parameters	5 kW	50 kW	1 MW	Unit
Production				
Electricity generation	4.8	49	970	MWh/year
Costs				
Capital cost	163.0	112.9	80.7	öre/kWh$_{elec}$
O&M cost	0	8.3	9.3	öre/kWh$_{elec}$
Reinvestment	7.3	4.6	3.3	öre/kWh$_{elec}$
Electricity certificates	-7.2	-14.5	-14.5	öre/kWh$_{elec}$
Investment support	-57.0	-39.5	0	öre/kWh$_{elec}$
Taxes & fees	0	0	0.5	öre/kWh$_{elec}$
Results				
Electricity generation cost without policy instruments and investment support	170	126	93	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	106	72	79	öre/kWh$_{elec}$

The electricity generation cost for photovoltaics is dominated by the cost of capital. The cost of capital level consequently strongly affects the electricity generation cost. If an interest rate of 3% is used for a 5 kW plant, you get an electricity generation cost, without policy instruments and investment support, at SEK 1.28/kWh, compared to SEK 1.70/kWh about 6% interest rate is used.

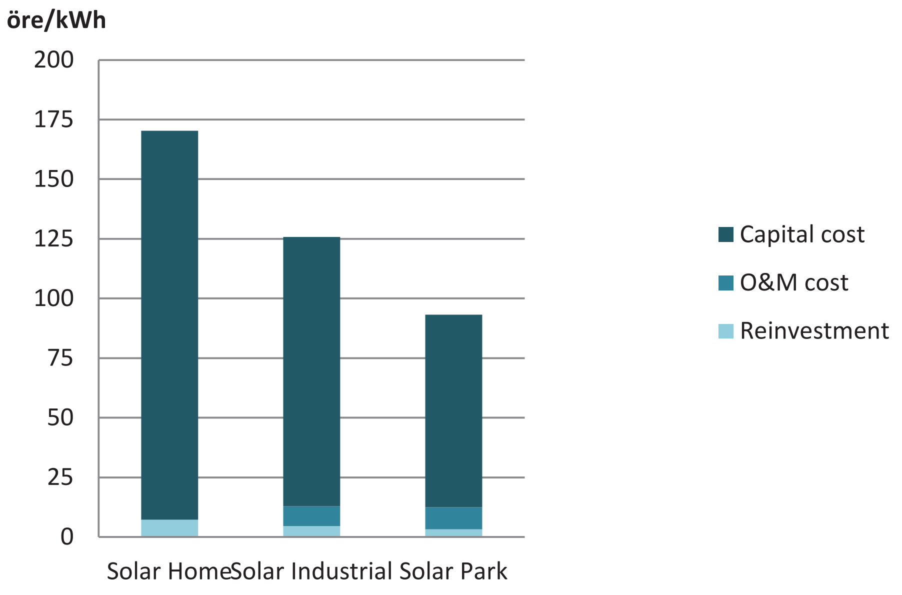

Figure 4-61. Electricity generation costs excluding policy instruments for photovoltaics

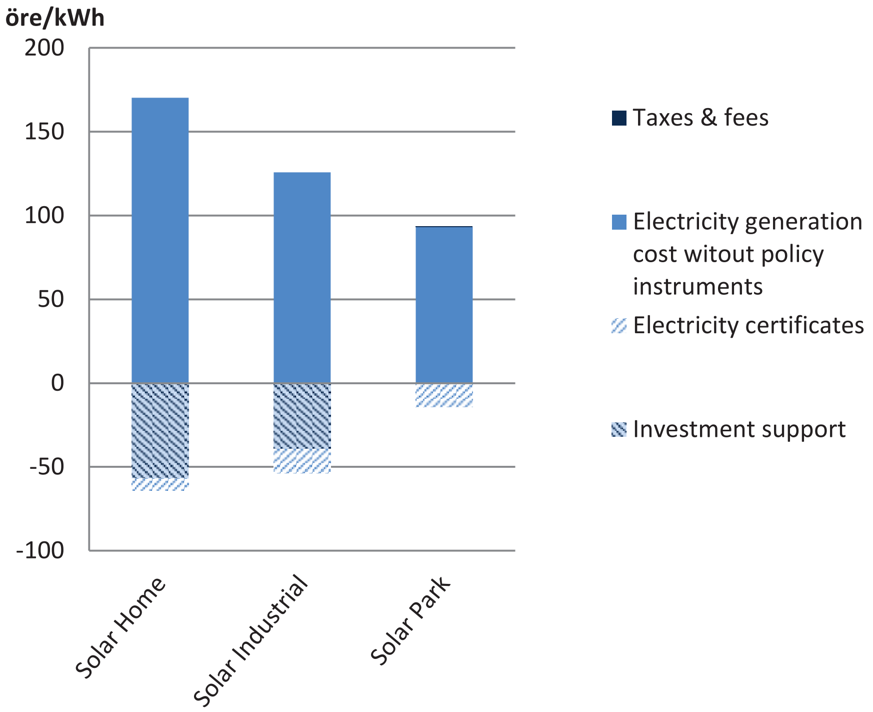

Figure 4-62. Electricity generation costs including policy instruments for photovoltaics

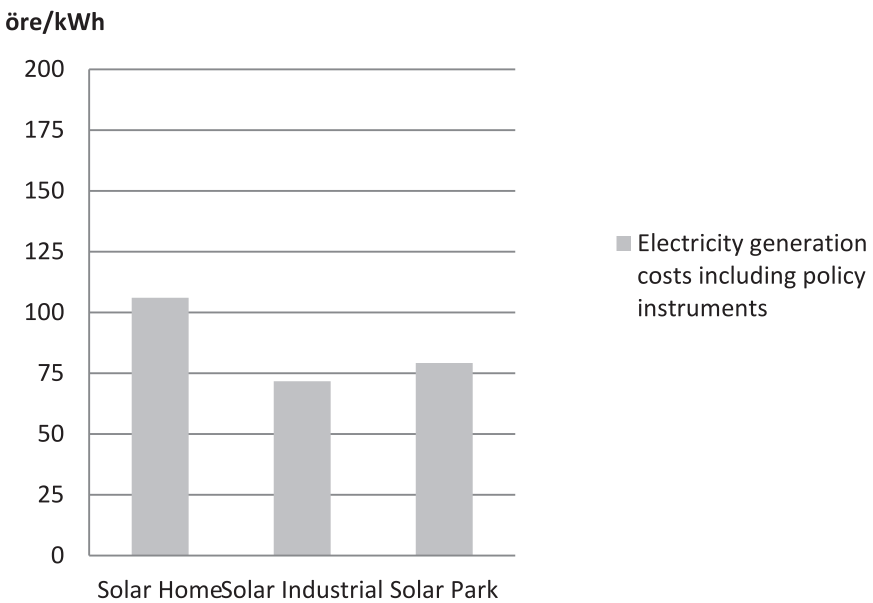

Figure 4-63. Resulting electricity generation costs including policy instruments for photovoltaics

4.14 Residual heat-ORC – Semi-commercial

As defined in this report, semi-commercial technologies are new, and can probably be purchased with limited warranties. This means that the supporting data for the costs is limited while the calculation assumptions are based on expectations, particularly for operating time and availability. This generally produces a greater level of uncertainty in the data than it does for the commercial technologies presented in Chapter 4.1 - 4.13.

4.14.1 Technology description

Residual heat-ORC is based on the same principle as Bio-ORC described in 4.10.1. The only difference is that the heat source is the residual heat from an external process and that the plant operates between much lower temperatures which means a hot oil boiler is unnecessary. The aim is to harness the energy in the residual heat to generate electricity that would otherwise be lost.

ORC plants for residual heat are usually stand-alone systems; container-solutions that include the entire ORC module. The things the plant owner adds are pipe installation, cooling water connection and power cables. The supplier Opcon Energy Systems has an ORC module of this model. The module includes a boiler and a condenser where the working fluid is vaporised and condensed. The vaporised working fluid is expanded in a twin screw turbine coupled to a generator. Electricity generation varies with the flow and temperature of the residual heat and the cooling water.

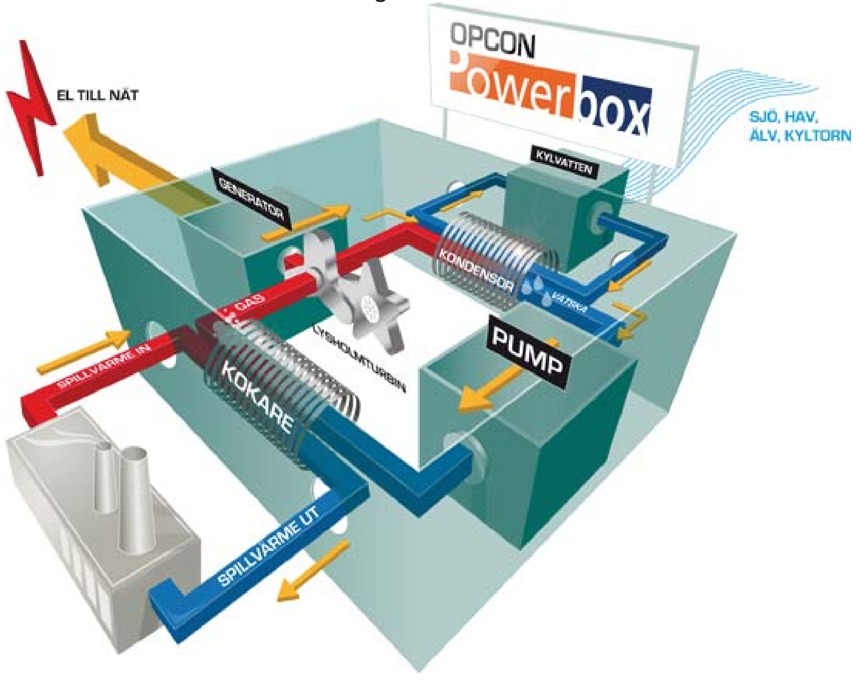

Figure 4-64. Illustration of Residual heat-ORC from Opcon Energy Systems. Source: Opcon Energy Systems [110].

4.14.2 Development trends

General trends for ORC systems are described in Chapter 4.10.2.

Several industries in Sweden have installed ORC modules for generating electricity from residual heat in recent years. Munksjö Aspa Works installed an ORC module in 2008 with an ammonia-based working agent. The ORC module is owned and operated by the supplier Opcon Energy Systems, in Munksjö and is responsible for the connection of the module. There is an agreement between the parties for the pricing of the electricity generated, while the ORC plant is also used to raise the temperature of incoming water for the recovery boiler at the works. Unfortunately, the ORC plant has recurrent problems with the leakage of ammonia, which limits operating time[31].

Stora Enso Skutkär installed a similar plant in 2009 but with a Freon-based working agent, R410A. The layout is, according to Goldschmidt [68], the same as at Munksjö Aspa works; Opcon Energy Systems owns and operates the ORC plant, Stora Enso Skutkär delivers the residual heat to the plant and purchases the electricity generated at an agreed price.

E.ON has been running a development project for a number of years together with Clean Power Technologies to develop an ORC module to generate electricity by heating water from the Elmeverket works in Älmhult. Commissioning of the plant is scheduled for the autumn of 2014.

ORC technology is still young and developing, which is why it is still classified as semi-commercial.

4.14.3 Technology-specific calculation conditions

The technology-based calculation conditions for Residual heat-ORC are based on the plants described by Goldschmidt [68], and using data from the supplier Opcon Energy Systems.

The expected full load hours is set to 8,000 hours per year which represents the base load, while the external process that drives the module is probably a commercial enterprise with generation throughout the year. Availability is applied to 95% according to data from Opcon Energy Systems.

The net electricity output of 500 kW is an estimate and represents the average output over the year, less internal electricity consumption.

Calculation conditions for Residual heat-ORC are summarised in Table 4-45.

[31] Contact with colleagues at the Munksjö Aspa Works, 25/02/2014

Table 4-45. Technology-specific calculation requirements for residual heat-ORC

Parameters	Value	Unit
Type of fuel	Residual heat	-
Expected full load hours	8,000	h/year
Availability	95 %	-
Resulting full-load hours	7,600	h/year
Electric output gross	0.8	MW
Electric output net	0.5	MW

4.14.4 Costs

Investment costs

The supplier Opcon Energy Systems says that an ORC module standard with a gross electrical output (rated output) of 800 kW will cost around 11 million. Depending on the available flows and temperatures over the year it means a net electrical output of around 500 kW mean over the year, less internal electricity consumption [68]. In addition to the ORC module you need to add design, pipe installation, cooling water connections, any pumps, power cables and switchgear. According to Goldschmidt [68], this corresponds to between SEK 1 and 4 million depending on the conditions each plant is subject to, if additional cooling capacity is required or not, or if it is far between the plants, etc.

E.ON is installing an initial ORC module of 250 kW_{elec} gross for its district heating plant in Älmhultin 2014. The investment was estimated in 2013 to be a total of SEK 8 million; future units are expected by E.ON to cost SEK 4-5 million [111]. What is included in the investment in detail is not known. The project at Älmhult is a development project that has been delayed in instalments due to problems at the supplier and will be completed in autumn 2014[32].

ORC technology is still young in Sweden and suppliers have had trouble delivering functioning plants. A total investment cost of a future ORC addition of an equivalent of 500 kW_{elec} net in annual average output, the need for new cooling capacity, is assumed based on the references mentioned as SEK 15 million, SEK 30,000/$kW_{elec.}$ The economic life is 15 years, based on a technical lifespan of 20 to 25 years.

Accordance to Opcon Energy Systems, a n ORC addition takes from a few weeks to a few months to install, depending on the prevailing conditions in respect of factors such as process and cooling systems. In the calculation application, only the full year is used as the construction period and for the calculation of the construction interest, which assumes that the entire investment is therefore assumed to burden year 0.

[32] Contact with colleagues at E.ON Värme, 01/07/2014

Operating and maintenance costs
Opcon Energy Systems, says an O&M cost only applies to its Opcon Powerbox at about SEK 150,000/year, at an availability of 95%. The majority of the cost comes from the overhauling of the turbine completed after 40,000 hours of operation.

Goldschmidt [68] believes that the O&M costs for an ORC module are comparable to heat pumps; about SEK 60,000/year for staff and 1.5% of the investment for other O&M costs.

The O&M cost is applied based on the mentioned references at SEK 480/kW$_{elec}$ per year.

Economic policy instruments
If the residual heat that drives the ORC module comes from renewable energy, the plant is entitled to have electricity certificates, which is assumed in this report.

Summarised costs
Costs and policy instruments for residual heat-ORC are summarised in Table 4-46.

Table 4-46. Summarised costs for residual heat-ORC

Parameters	5 MW	Unit
Specific investment	25,000	SEK/kW$_{elec, gross}$
Specific investment	30,000	SEK/kW$_{elec, net}$
Construction period	0	year
Depreciation period	15	year
O&M	480	SEK/kW$_{elec, net}$
Fuel cost*	0	SEK/MWh$_{elec}$
Electricity certificate**	-190	SEK/MWh$_{elec}$
Property tax	0.5	öre/kWh$_{elec}$

* The residual heat is assumed to be free of charge in line with the reasoning in Chapter 3.2
** Electricity certificates are paid for 15 years.

4.14.5 Results

Annual production, costs and the resulting electricity generation cost for residual heat ORC are summarised inTable 4-47 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments.

The cost of electricity generation is calculated based on 8,000 expected full-load hours and with an availability of 95%, which implies that the residual heat with a sufficient temperature is available all year round. As mentioned in previous chapters, suppliers have had problems delivering plants that can achieve an adequate level of generation, despite good access to residual heat.

In the current situation, accessibility is lower than 95% and O&M costs are probably higher. Therefore, the calculated power generation cost is seen as a cost that can be achieved for a well-functioning system as the plant can be considered to be commercial.

Table 4-47. Results for residual heat-ORC with 6% cost of capital

Parameters	Value	Unit
Production		
Electricity generation	3.8	GWh/year
Costs		
Capital cost	51.9	öre/kWh$_{elec}$
O&M cost	6.3	öre/kWh$_{elec}$
Fuel cost	0	öre/kWh$_{elec}$
Electricity certificates	-19.0	öre/kWh$_{elec}$
Taxes & fees	0.5	öre/kWh$_{elec}$
Results		
Electricity generation cost without policy instruments	58	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	40	öre/kWh$_{elec}$

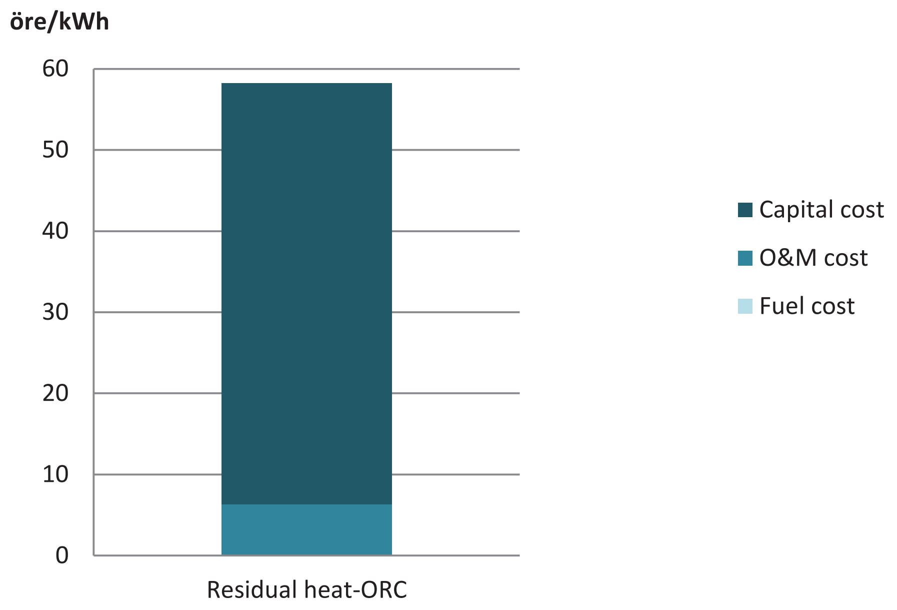

Figure 4-65. Electricity generation costs excluding policy instruments for residual heat-ORC

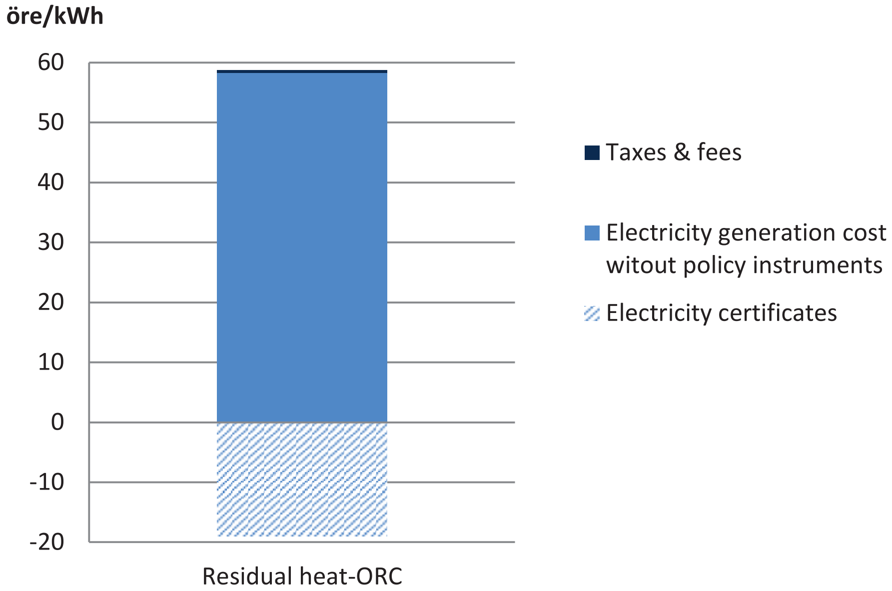

Figure 4-66. Electricity generation costs including policy instruments for residual heat-ORC

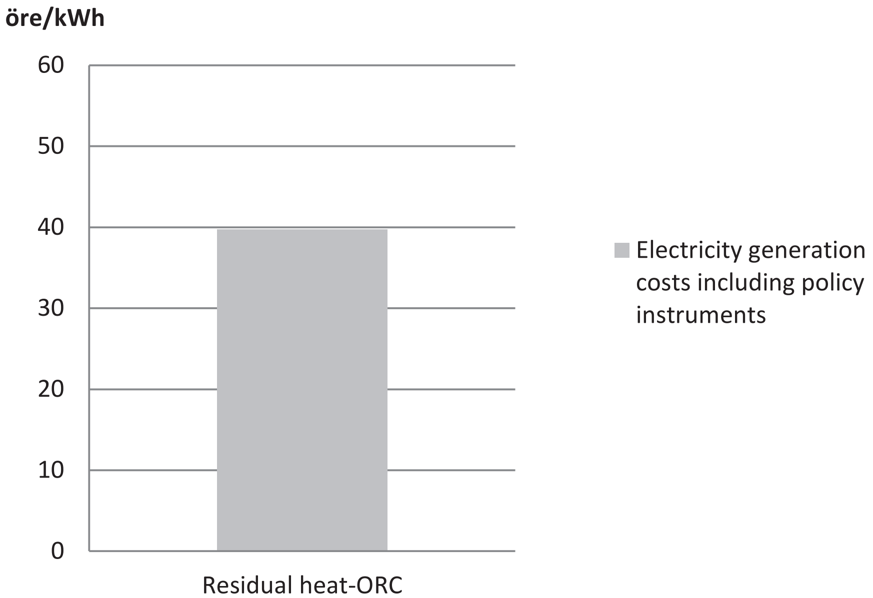

Figure 4-67. Resulting electricity generation costs including policy instruments for residual heat-ORC

4.15 RDF gasification gas boiler – Semi commercial

As defined in this report, semi-commercial technologies are new, and can probably be purchased with limited warranties. This means that the supporting data for the costs is limited while the calculation assumptions are based on expectations, particularly for operating time and availability. This generally produces a greater level of uncertainty in the data than it does for the commercial technologies presented in Chapter 4.1 - 4.13.

Co-firing methods, with gasification as a precursor to combustion, which in this report are considered as semi-commercial technology, attracted a lot of interest in the late 90s. More than 15 years ago this was considered by many as a way to kick-start a market for increased quantities of biomass fuels to replace fossil fuels for power generation in Europe, while the power industry would thereby engage in and become a driving force for the commercialisation of biomass fuel production. By being a marginal part of the fuel for large coal boilers, a high efficiency could be attained with more limited investment. The gasification technology, i.e. indirect co-firing, was seen as a way of avoiding the problem of direct co-firing that was feared, among other things, with the corrosion to boilers, increased slagging/fouling and difficulty in disposing of carbon ash and other residues resulting from the admixture of ash from biomass fuel.

However, direct co-firing has been the dominant method as this requires less investment and fuels can be bought cheaply on a spot market basis, etc., and this is now being applied at many plants.

Indirect co-firing based on gasification has existed or exists in a few commercial establishments of 45-80 MW fuel output and gas from these are fired as a small share in boilers of several hundred MW:

- Burlington
- Zeltweg
- Lahti
- Ruien
- Getrudienberg (AMERGAS)

CFB gasifiers are used in these plants, and as they are now run (both Burlington and Getruidenberg were originally built with extensive gas purification) where some cooling of the gas and dust-separation in a cyclone or ceramic filter is performed before the gas is burned in the boiler. This means that requirements are set for the flue gas after the boiler, and that the fuel sample is more limited.

Lahti's latest venture (see detailed description below) means increased purification of gas between the gasifier and power boiler, leading to higher electric conversion efficiency, in that the boiler can handle higher steam data without any problems with corrosion.

4.15.1 Technology description

Description of the technology has largely been taken from Waldheim [112].

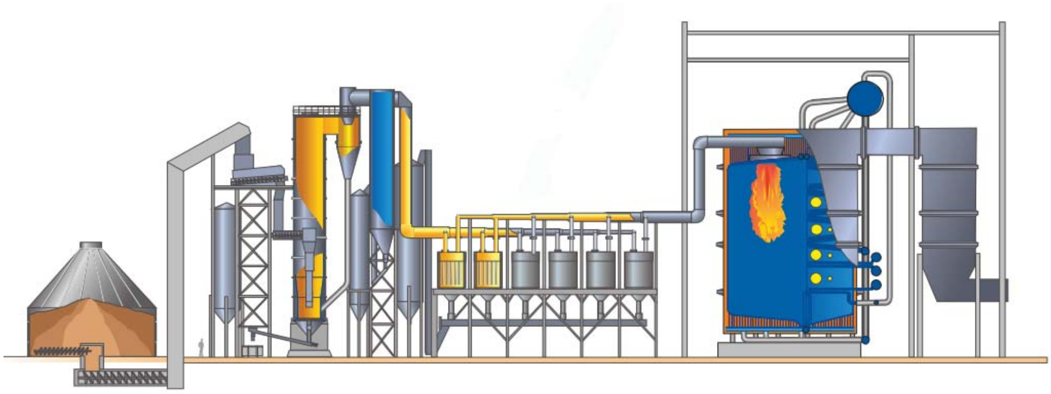

Figure 4-68. Schematic gasification and combustion in Kymijärvi II, Lahti. Source: Valmet Power [113]

Pretreatment and gasification

The fuel is preprocessed by sorting non-combustible materials, glass and metal, followed by size measurement and adjustment to the gasifier that is appropriate for the selected fraction size. The moisture content of these fuels varies, and may be low, while the proportion of energetic plastic can be high. The fuel is dried in some cases. Via a feeding system, fuel is supplied to the gasifier along with gasification air, that is preheated from the outgoing hot gas. The gasifier can take many forms, but for this application, a suitable CFB gasifier works best. The gas from the gasifier passes a cyclone for separating coarse particles.

Gas purification

Gas can be purified with or without catalytic treatment. In the newest plant for the gasification of waste, Kymijärvi II in Lahti, gas is purified without catalysis. The gas that is formed is cooled from 850-900° C to 400 °C and the particles are separated in the ceramic filter thereafter. Alkali chlorides and heavy metals are then condensed and can be disposed of by the filters. In contrast, most of tar substances are still in the gas phase and condensation of these along with clogging of the equipment should be avoided.

Energy recovery and emissions

The newest plant in Lahti, Kymijärvi II, was commissioned in 2012 and comprises two parallel 80 MW_{fuel} CFB gasifier and a gas-fired power boiler. The fuel is SRF (Solid Recovered Fuel) and has a moisture content of between 20 and 30%. In total, 250,000 tonnes of SRF are gasified per year. The gas is burned in a boiler with steam data at 540 °C and 120 bar (g). The turbine produces 50 MW of electricity and 90 MW of heat, which gives an alpha value of 0.55 and an overall efficiency of 87.5%. The emissions from the plant are up to 240 mg/MJ for both NO_x and SO_x [114].

4.15.2 Development trends

When waste fuels are used, the driving force of the economy is added to improve payments being received for receiving the fuel (negative fuel price). Meanwhile, the same favourable revenue is generated in whole or in part for biomass fuels, but for an additional investment that is far lower than for a waste incinerator, and with performance that significantly exceeds those that can be attained using a boiler in the conventional design. Kymijärvi II represents a breakthrough in that purification of the gas can be carried out efficiently at high temperatures without catalysis and ensuring high electric conversion efficiency. One risk factor may be the precipitation of tar in the filter.

Gas purification is very important for ensuring waste gasification can find new applications. If mercury and sulphur can be separated in addition to the chlorine and heavy metals that can already be separated in the gas purification process using present technology, it is within the realms of possibility to have the gas “classified as green”, whereby usage opportunities would be substantially broadened and even be able to include gas turbines and gas engines. This is directly related to tar reduction in connection with gasification, as a reduced amount of tar leads to the filter temperature being lowered below 200 °C, allowing the mercury to separate. There is no applicable technology for sulphur at the current time. Only when the gas has become so clean of tar, it can be cooled below the dew point, then technology comes into play albeit costly and complicated. The capture of sulphur under these conditions therefore is an interesting area of research.

4.15.3 Technology-specific calculation conditions

The technology-specific calculation assumptions used in calculating the electricity generation cost are given inTable 4-48 and are based on the gasification plant Kymijärvi II in Lahti [114].

Table 4-48. Technology-specific calculation conditions for RDF gasification, 50 MW

Parameters	Value	Unit
Type of fuel	RDF	-
Heating value	4.2	MWh/tonne$_{fuel}$
Expected full load hours	7,500	h/year
Availability	95 %	-
Resulting full-load hours	7,125	h/year
Electric output gross	56.1	MW
Electric output net	50	MW
Electric conversion efficiency*	31.2 %	-
Alpha value net**	0.56	-
Heat output	90	MW
Total efficiency	87 %	-
NO_x emissions	40	mg NO_2/MJ$_{fuel}$
Sulphur emissions	0	mg S/MJ$_{fuel}$
CO2 emissions	35	g CO_2/MJ$_{fuel}$

* Electric conversion efficiency is defined as net electricity through fuel.
** The alpha net value is defined here as net electricity through net heating.

4.15.4 Costs

Investment costs

The gasification plant Kymijärvi II in Lahti, taken into operation in 2012, is used as the base. The investment amounted to 157 M € [113] and included fuel receiving, specific fuel preparation, gasifier, gas purification, gas boiler, flue gas purification and turbine and scarification. The existing control room and turbine hall was used [115]. The total cost of a "greenfield" plant corresponding to Kymijärvi II is estimated at about SEK 1,600 million.

Operating and maintenance costs

The variable operating and maintenance cost should be the same size as for an RDF-fired co-generation boiler and is estimated to be SEK 55/MWh fuel. The fixed operating and maintenance cost is estimated to be the same as for the RDF-fired plant, SEK 1,900/kW of electricity$_{net}$.

Fuel costs

Depending on the degree of reprocessing the fuel cost for RDF may vary between SEK 0 and 50/MWh. A charge of SEK 25/MWh fuel is applied.

Summarised costs

Costs and policy instruments for RDF co-generation plants are summarised in Table 4-49.

Table 4-49. Summarised costs and policy instruments for RDF gasification, 50 MW

Parameters	Value	Unit
Specific investment	32,000	SEK/$kW_{elec,\ gross}$
Specific investment	35,900	SEK/$kW_{elec,\ net}$
Construction period	2	year
Depreciation period	25	year
Fixed O&M	1900	SEK/$kW_{elec,\ net}$
Variable O&M	55	SEK/MWh_{fuel}
Fuel price	25	SEK/MWh_{fuel}
Heat crediting*	-324	SEK/MWh_{heat}
NO_x repayment	-2.5	öre/kWh_{elec}
NO_x fees	2.3	öre/kWh_{elec}
Emission rights	2.0	öre/kWh_{elec}
Property tax	0.5	öre/kWh_{elec}

* Heat crediting is described in Chapter 3.6.2.

4.15.5 Results

Annual production, costs and the resulting electricity generation cost for RDF gasification are summarised inTable 4-50 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments.

RDF gasification has a relatively low investment cost per installed kW compared to other solid-fuel-fired power plants while the electric conversion efficiency is higher. Along with a low fuel cost, this provides low-cost electricity. However, the technology is in its development stage and the generation cost calculation is based on an availability on par with other waste-fired power plants and Kymijärvi I (>95%). However, at Kymijärvi I the gas is fired immediately without purification. At Kymijärvi II the gas is purified before the burners which, among other things, can lead to condensation of the tar. The availability and maintenance cost is therefore somewhat uncertain in this calculation. Therefore, the calculated power generation cost is seen as a cost that can be achieved for a well-functioning system as the plant can be considered to be commercial.

Table 4-50. Results for RDF gasification with 6 % cost of capital

Parameters	Value	Unit
Production		
Electricity generation	356	GWh/year
Heat production	641	GWh/year
Costs		
Capital cost	40.8	öre/kWh$_{elec}$
O&M cost	44.3	öre/kWh$_{elec}$
Fuel cost	8.0	öre/kWh$_{elec}$
Heat crediting	-58.3	öre/kWh$_{elec}$
NO_x repayment	-2.5	öre/kWh$_{elec}$
Taxes & fees	4.8	öre/kWh$_{elec}$
Results		
Electricity generation cost without policy instruments	35	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	37	öre/kWh$_{elec}$

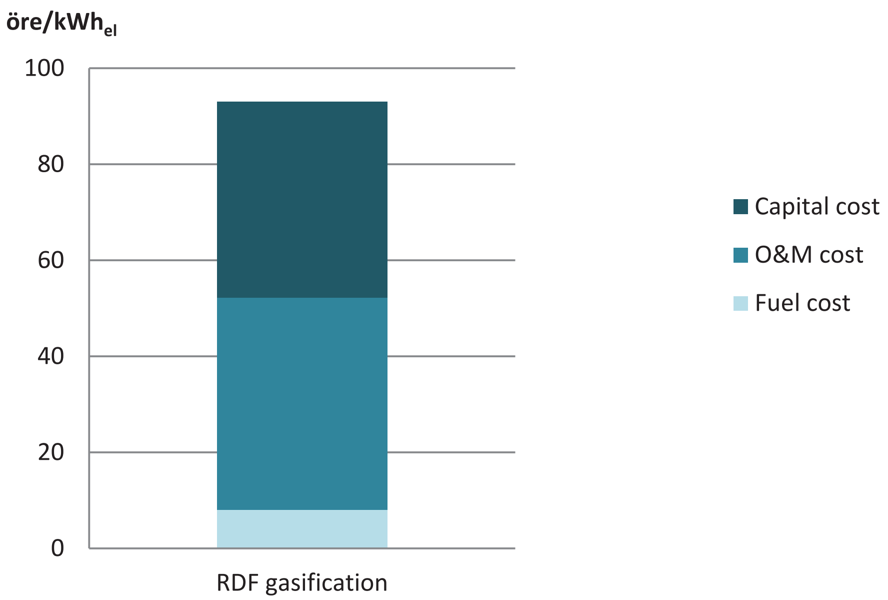

Figure 4-69. Generation costs of electricity and heat using RDF gasification, excluding policy instruments and heat crediting

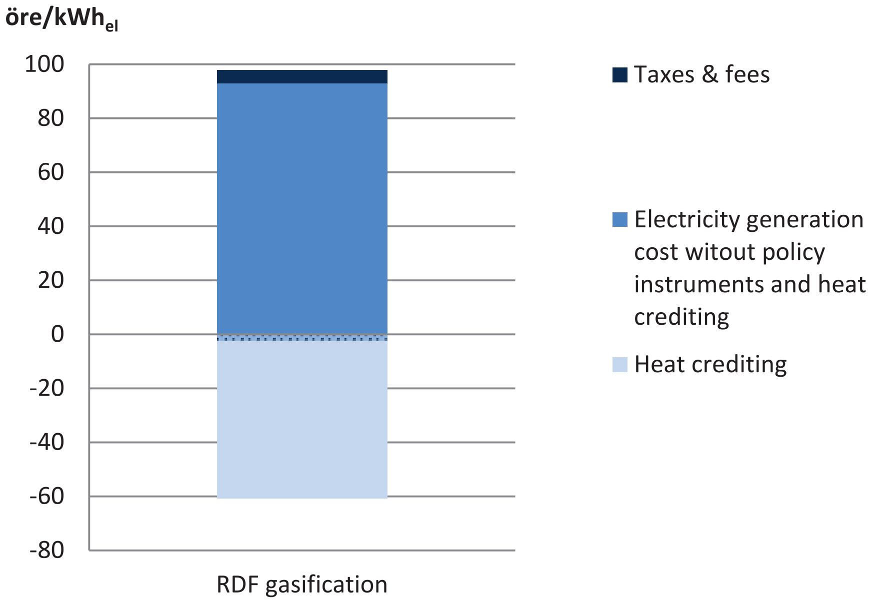

Figure 4-70. Electricity generation costs including policy instruments and heat crediting for RDF gasification

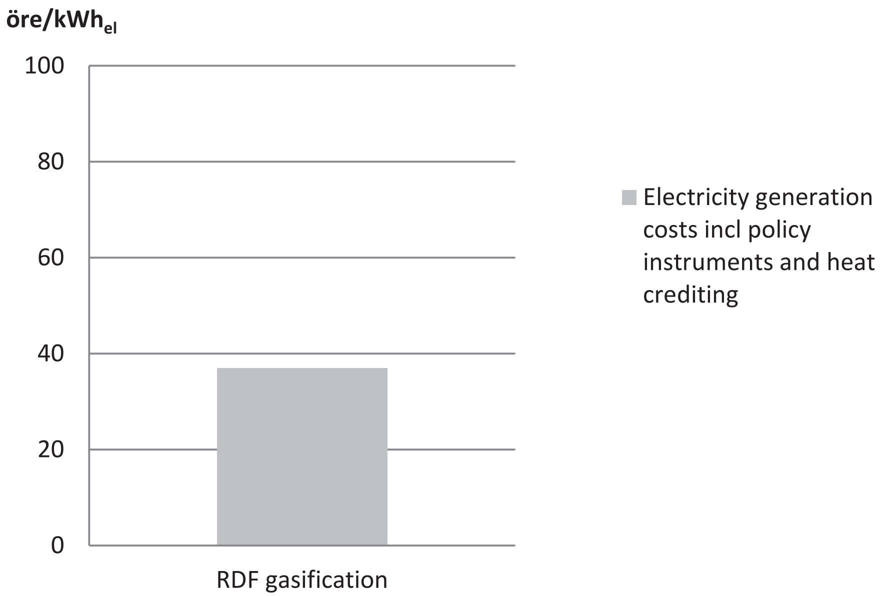

Figure 4-71. Resulting electricity generation costs including policy instruments and heat crediting for RDF gasification

4.16 Biomass fuel gasification gas engine – Semi commercial

As defined in this report, semi-commercial technologies are new, and can probably be purchased with limited warranties. This means that the supporting data for the costs is limited while the calculation assumptions are based on expectations, particularly for operating time and availability. This generally produces a greater level of uncertainty in the data than it does for the commercial technologies presented in Chapter 4.1 - 4.13.

4.16.1 Technology description

Gasification with gas engine, BIG ICE (Biomass Integrated Gasification Internal-Combustion Engineering), is interesting as it potentially has a higher electric conversion efficiency than what is considered economically optimal for small co-generation plants with boiler/steam cycle (1-15 MW of electricity). Examples of the plant configuration are shown schematically in Figure 4-72.

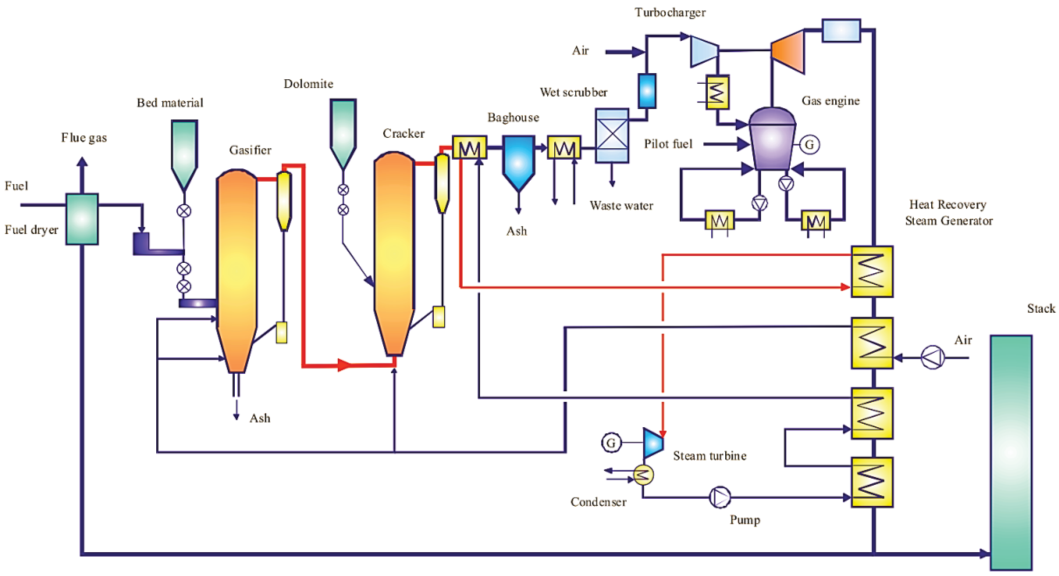

Figure 4-72. Examples of gasification plant with electricity generation through gas engine [112]

The biomass fuel is prepared to an appropriate particle size and dried to 10-15% moisture. Gases are used for heat recovery as the heating medium for drying. The prepared fuel is supplied to the gasifier, which is operated close to atmospheric pressures and as a result conventional input systems can be used. In the gasifier, fuel is converted into a gas at a peak temperature of 800-950 °C. Typically, the gasifier is configured as a fixed or bubbling fluidized bed, or as an indirect fluidized bed. For the gasification process, air is utilised (directly or indirectly) which is received from the fans or blowing machines.

After the gasifier, the gas can in some cases be treated to reduce the tar yield at high temperature, while in other cases, catalysis can be used. The gas is cooled, purified or unpurified, and is then cleaned of tar and particulates using scrubbers with water or oils (or a combination of different media) under or immediately over the gas dew point, depending on whether the water condensates or if the water vapour in the gas accompanies this to the engine.

The gasification technology that has attracted the most interest is the gasification of an indirect fluidized bed, which has become known through the plant at Güssing, Austria, which was commissioned in 2002 and has now a reported availability (gasifier + engine) of around 7,000 hours/year. The plant has a fuel output of 8 MW and produces 2 MW of electricity.

An additional five more plants (about 3-5 MW_{elec}) have been taken into operation in recent years, are scheduled or are under construction in Germany and Austria (for example, Villach, Oberwart, Klagenfurt and Ulm). Some of these are built as a combined cycle based on the ORC turbines, and a planned plant also utilises the AER (Absorption Enhanced Regeneration) where CO_2 is removed from the gas with a lime-based mineral that is regenerated in the combustion part which increases the calorific value.

Babcock Völunds plant in Harboøre, Denmark, is based on gasification in a fixed bed, with 3.5 MW of fuel supplied and 1 MW of electricity generation. It came into service in 2000, and since then the gasifier + engine have been running for over 80,000 hours in total. There are also three plants in Japan which were built by JFE under license from Babcock Völund.

One of the newer plants is being built in Newry, Ireland, with a downflow gasifier from Zero Point and a gas engine from the supplier GE Jenbacher. The gasifier and gas engine were commissioned in 2012 and when both gas engines are installed they will produce 3.6 MW of electricity from 6.7 MW of synthesis gas. The same supplier has provided a plant to Schwarzepumpe of 1.8 MW of electricity, installed in 2011.

4.16.2 Development trends

Gasification followed by gas engine is still an area of technology in its development stage, although a number of commercially-run plants are in operation. Control, automation, material selection to avoid low temperature corrosion and particle formation are areas where development is still in progress [116].

Several gas engine manufacturers operating in the product gas area, although GE Jenbacher still retain their dominant position. Engine development is happening in several areas (raising of the turbocharging pressure without condensation problems and tapping, individual control of ignition in each cylinder, lubricating oil systems, etc.). Here, both cost reduction and efficiencies have increased somewhat, but at a relatively slow pace. The greatest potential for improvement lies in a systems mindset with the integration of waste heat utilisation for drying, steam or ORC cycles in order to achieve higher efficiencies. Additional development is expected to enable both higher electricity efficiencies such as lower investment costs and larger plants.

4.16.3 Technology-specific calculation conditions

Performance and cost in this study have been assessed for co-generation for two plant sizes – 1 MW of electricity and 5 MW of electricity. For a 5 MW plant, the new plants in Newry [117] [118] and Enfield [119] represent the foundation. For the 1 MW plant there are no new installations planned after 2011 to start from, but Babcock & Wilcox Vølund specify technical specifications for a 1 MW of electricity plant [120] and these are used in the calculation of electricity cost.

The technology-specific calculation assumptions used in calculating the electricity generation cost are given in Table 4-51.

Table 4-51. Technology-specific calculation conditions for BIG-ICE, 1 and 5 MW

Parameters	1 MW	5 MW	Unit
Type of fuel	Wood chips	Wood chips	-
Heating value	2.6	2.6	$MWh/tonne_{fuel}$
Expected full load hours	5,000	5,000	h/year
Availability	96 %	96 %	-
Resulting full-load hours	4,800	4,800	h/year
Electric output gross	1.1	5.8	MW
Electric output net	1	5	MW
Electric conversion efficiency*	25.5 %	31.0 %	-
Alpha value net**	0.48	0.52	-
Heat output	2.1	9.6	MW
Total efficiency	79 %	91 %	-
NO_x emissions	75	75	mg NO_2/MJ_{fuel}
Sulphur emissions	0	0	mg S/MJ_{fuel}
CO2 emissions	0	0	g CO_2/MJ_{fuel}

* Electric conversion efficiency is defined as net electricity through fuel.
** The alpha net value is defined here as net electricity through net heating.

4.16.4 Costs

Investment costs

Investment costs used in the calculations are based on two of the newer installations at Newry and Enfield [117] [118] [119]. The cost of the plant at Newry producing 3.6 MW_{elec} is GBP 14.7 million giving about SEK 43,800/$kW_{elec, gross}$. The cost of the plant at Enfield producing 10.4 MW_{elec} is GBP 45 million giving about SEK 46,500/$kW_{elec, gross}$. The cost for a case with 5 MW_{elec} is estimated thereby to be SEK 45,000/$kW_{elec, gross}$. For the case of 1 MW_{elec} the cost is estimated at SEK 55,000/$kW_{elec, gross}$.

Operating and maintenance costs

Operating and maintenance costs are specified by Rush Nova et al. [121] to SEK 67/MWh of electricity, equivalent to about SEK 18/MWh fuel. This is roughly the same size as the variable operating and maintenance costs for biomass fuel-fired co-generation plants. Rusanova et al. does not indicate any operational and maintenance costs. This is applied at 2% of the investment cost.

Fuel costs

Fuel costs for forest chips amount to SEK 200/MWh, based on lower heating values and damp wood chips.

Summarised costs

Costs and policy instruments for BIG-ICE are summarised in Table 4-52.

Table 4-52. Summarised costs and policy instruments for BIG-ICE, 1 and 5 MW

Parameters	1 MW	5 MW	Unit
Specific investment	55,000	45,000	SEK/$kW_{elec, gross}$
Specific investment	60,500	52,200	SEK/$kW_{elec, net}$
Construction period	1	1	year
Depreciation period	15	15	year
Fixed O&M	1,210	1,040	SEK/$kW_{elec, net}$
Variable O&M	18	18	SEK/MWh_{fuel}
Fuel price	200	200	SEK/MWh_{fuel}
Heat crediting*	-499	-499	SEK/MWh_{heat}
NO_x repayment**	0	-2.6	öre/kWh_{elec}
NO_x fees**	0	4.4	öre/kWh_{elec}
Electricity certificate***	-190	-190	SEK/MWh_{elec}
Property tax	0.7	0.7	öre/kWh_{elec}

* Heat crediting is described in Chapter 3.6.2.
** Combustion plants with electricity and/or heat <25 GWh are not covered by the nitrogen oxide charge.
*** Electricity certificates are paid for 15 years.

4.16.5 Results

Annual production, costs and the resulting electricity generation cost for BIG-ICE are summarised inTable 4-53 and in subsequent diagrams with a cost of capital of 6%. The results are presented both with and without economic policy instruments.
The smaller plant of 1 MW has a higher capital cost per installed kW_{elec} and an electric conversion efficiency below 5 MW per plant which leads to almost 50% higher electricity generation costs for the smaller plant than the larger one. Compared to 5 MW biomass fuel-fired co-generation plants, the electricity generation cost is lower. Despite this, the technology has yet to take hold in

Sweden. The reason for this may be the maturity of the technology especially regarding gas purification. With increasing positive experiences from the technology, the economic calculation should improve through a longer depreciation period etc.

Table 4-53. Results for BIG-ICE with 6% cost of capital

Parameters	1 MW	5 MW	Unit
Production			
Electricity generation	4.8	24	GWh/year
Heat production	10.0	46	GWh/year
Costs			
Capital cost	132.4	114.2	öre/kWh$_{elec}$
O&M cost	32.3	27.5	öre/kWh$_{elec}$
Fuel cost	78.4	64.5	öre/kWh$_{elec}$
Heat crediting	-104.8	-95.8	öre/kWh$_{elec}$
NO_x repayment	0.0	-2.6	öre/kWh$_{elec}$
Electricity certificates	-19.0	-19.0	öre/kWh$_{elec}$
Taxes & fees	0.7	5.1	öre/kWh$_{elec}$
Results			
Electricity generation cost without policy instruments	138	110	öre/kWh$_{elec}$
Electricity generation cost with policy instruments	120	94	öre/kWh$_{elec}$

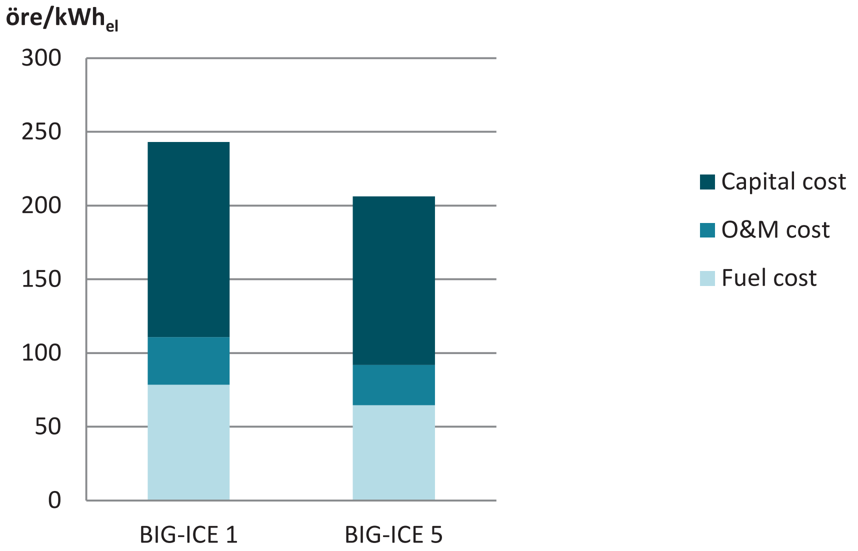

Figure 4-73. Generation costs of electricity and heat using BIG-ICE, excluding policy instruments and heat crediting

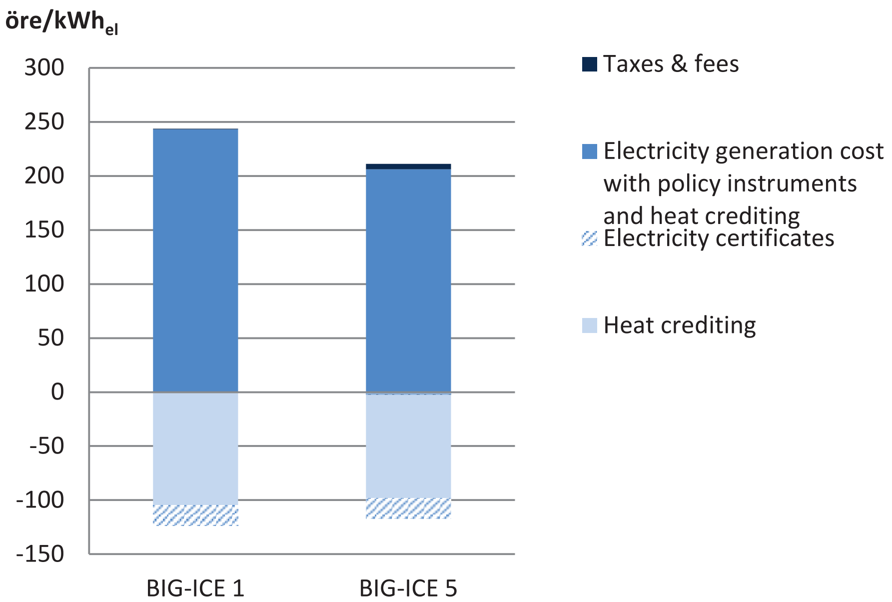

Figure 4-74. Electricity generation costs including policy instruments and heat crediting for BIG-ICE

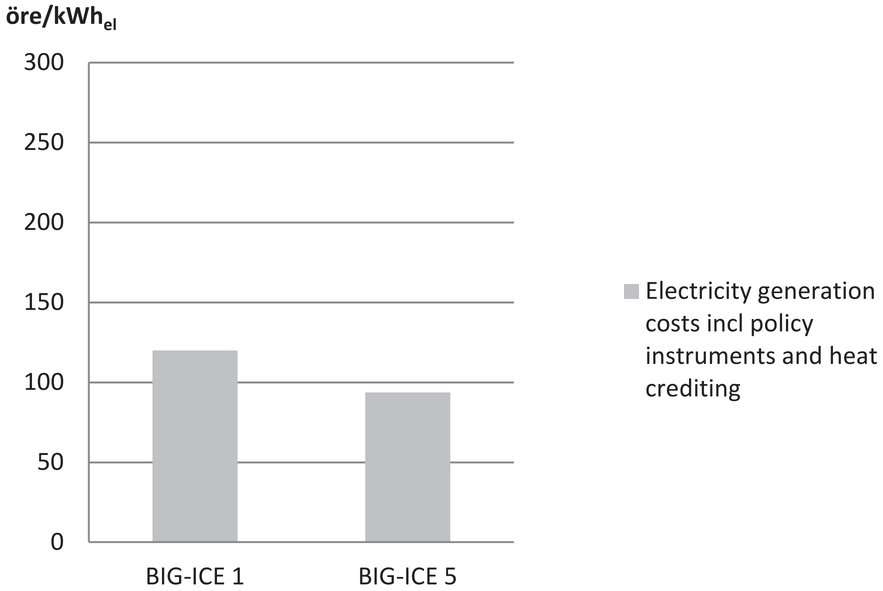

Figure 4-75. Resulting electricity generation costs including policy instruments and heat crediting for BIG-ICE

4.17 Coal condensation with CCS – Future technology

For future technologies, the report covers development trends and driving forces, technical development and costs as well as critical components together with a brief assessment of technical performance, unlike the commercial and semi-commercial technologies presented in Chapter 4.1 - 4.13 and 4.14 - 4.16 where an electricity generation cost have been presented.

4.17.1 Technology description

The powerful incentive to reduce CO_2 emissions has led to the development of coal condensing power with CO_2 separation and storage, *carbon capture and storage* (CCS). To capture, separate, compress and store carbon dioxide is an energy intensive process, which means that a plant with CCS technology has a much lower efficiency, 8-12% units lower [10].

CO_2 separation with the disposal and storage of CO_2 is not a new technology in itself, as it has been used in the oil industry for many years in order to improve oil recovery. However, the CCS method is something new in the power industry and there is no technology today that is commercially mature for large power plants.

Separation techniques
There are three main principles for carbon capture from fossil power plants;

- Post-combustion; carbon dioxide is captured from flue gases.
- Pre-combustion; carbon is removed from the fuel before combustion.
- Oxy-fuel combustion; combustion of the fuel takes place with oxygen and recycled carbon dioxide instead of air.

The performance and cost of capture and compression from coal-fired condensing power plants is relatively similar to the above described separation techniques, in the same conditions and with about the same degree of "optimism/conservatism" [1].

Transport and storage of CO_2

The CO_2 separated in a power plant is compressed into liquid form and transported to the place where geological storage is to occur. For quantities that would be relevant for the transport of CO_2 from large power plants, pipelines on land and pipeline and/or vessels are deemed to be most cost-effective [122].

The largest storage potential is in salt water filled porous geological formations, saline aquifers, which have dense layers of rock above them. At the place of storage, carbon dioxide is injected below ground or the seabed at least 800 metres depth, where it remains in liquid form (supercritical) from the natural hydrostatic pressure. Eventually the carbon dioxide dissolves in the water and the saturated solution will drop down towards the bottom of the aquifer. After a very long time, carbon dioxide will have reacted with the bedrock and be permanently mineralised [122].

4.17.2 Development trends

In February 2014, there were 12 large-scale CCS projects in operation worldwide, nine under construction and 39 different at various stages of planning [123]. The largest number are in North America, including one of the first large-scale CCS projects for power generation - *The Boundary Dam Integrated Carbon Capture and Sequestration Project* in Estevan, Canada. There is an existing coal power plant of 110 MW, which has been modernised and supplemented with *post-combustion CCS,* and which is expected to be in full commercial operation in 2014/2015 [124], [123], [125].

The development of coal-based CCS has partly stalled in Europe, and a number of demonstration projects have been delayed or abandoned. Vattenfall's CCS investment at *Jänschwalde* coal power plant in Germany was closed in 2011 due to public opposition, which has led to the development of new testing plants in Germany being postponed. No new large-scale CCS project has moved to the construction phase in more than a decade in continental Europe [123].

Since 2011, Sweden has, like most EU countries, only implemented the EU's CO_2 storage directive under the sea – in other words it is not possible to obtain permits for onshore-based CO_2 storage[33]. This is constraining the potential of CCS technology and increasing storage costs of carbon dioxide in Sweden.

[33] Contact with Clas Ekström, Vattenfall R&D 26/02/2014

4.17.3 Estimated costs

The cost of capture and compression of CO_2 consists of investments in process equipment, increased fuel costs due to the processes consuming a lot of energy, and O&M costs for capture and compression.

Investment costs

In 2013 it was estimated that the specific investment cost of a carbon-based condensing power plant of 650 MW with CCS technology to the equivalent of SEK 34,500/kW_{elec} [26].

Tola and Pettinau [28] have compared, among other data, the costs of various carbon-based technologies in 2014, with and without CCS. The investment cost for pulverised coal-fired USC plants is estimated excluding financial expenses over the construction period at around SEK 35,000/kW_{elec} with CCS.

Operating and maintenance costs

The O&M costs for a carbon-based condensing power plant with CCS in 2013 is estimated to be over 110% higher than for an equivalent coal plant without CCS [26]. Total O&M costs for the power plant were estimated at a fixed and variable component of around SEK 530/kW_{elec} and more than SEK 60/MWh_{elec} [26].

Electricity generation costs

In 2011, the European Technology Platform for CCS, known as the Zero Emission platform *(ZEP),* published the estimated future costs of capture, transport and storage of CO_2 from coal and natural gas-based power plants after 2020 [126]. The electricity generation costs for a pulverised-coal-fired USC power plant with CCS are calculated to be between around EUR 70-100/MWh_{elec}, when the electricity generation cost of an equivalent power plant without CCS was estimated at about EUR 45-55/MWh_{elec} using the same calculation conditions. As only offshore storage will be needed in Sweden, the cost of transportation and storage of CO_2 will be high and the electricity generation cost will therefore be at the high end of the range.

4.18 Gas co-generation condensation with CCS – Future technology

For future technologies, the report covers development trends and driving forces, technical development and costs as well as critical components together with a brief assessment of technical performance, unlike the commercial and semi-commercial technologies presented in Chapter 4.1 - 4.13 and 4.14 - 4.16 where an electricity generation cost have been presented.

4.18.1 Technology description

The methods for capture, transport and storage of CO_2 for coal-based power plants are described in Chapter 4.17.1.

For the capture of CO_2 from natural gas-fired combined cycle power plants, "post-combustion capture" is the technology that is likely to be used for demonstration. ”Oxy-fuel” combustion requires modified/new types of gas turbines and “pre-combustion” is now considered not to offer any significant potential advantages over “post-combustion” capture [1].

4.18.2 Development trends

Compared to the development of CCS technology for coal-based condensing power in Chapter 4.17.2 a similar trend for natural gas-based cycles is underway, but it does not seem as intense as seen from a global perspective. Some of the reasons may be that the cost per captured amount of CO_2 is 2-3 times as high for a gas co-generation plant compared to a coal condensing plant and that the present gas co-generation plants use fuel more efficiently, i.e. operates at higher efficiency levels.

4.18.3 Estimated costs

The cost of capture and compression of CO_2 consists of investments in process equipment, increased fuel costs due to the processes consuming a lot of energy, and operating and maintenance cost for capture and compression.

It was estimated in 2013 that specific investment cost for a gas co-generation plant of 340 MW with CCS at just under SEK 14,000/$kW_{elec.}$ The fixed and variable O&M-cost were estimated at about SEK 210/kW_{elec} and approximately SEK 45/$MWh_{elec.}$ [26]

Electricity generation costs
The European Technology Platform for CCS *(ZEP)* has made a comparison of future electricity costs for natural gas co-generation plants with or without CCS. Without CCS the electricity generation cost is estimated to be in a range depending on the fuel cost of approximately EUR 46-90/MWh_{elec}; with CCS the cost is estimated at between EUR 70-120/MWh_{elec} depending on fuel prices and the storage method. [126]

4.19 Biomass gasification combined cycle – Future technology

For future technologies, the report covers development trends and driving forces, technical development and costs as well as critical components together with a brief assessment of technical performance, unlike the commercial and semi-commercial technologies presented in Chapter 4.1 - 4.13 and 4.14 - 4.16 where an electricity generation cost have been presented.

When biomass fuel gasification is combined with a gas turbine and steam turbine in a combined cycle, known as BIGCC (Biomass Integrated Gasification Combined Cycle), it is possible to have both interesting plant sizes, about 15-100 MW of electricity, high efficiency and high ratio of generated electricity and heat in co-generation applications. Overall, this could provide significant potential in relation to conventional methods based on boilers and steam turbines, in that it makes it possible to produce substantially more electricity from a given district heating base. However, this method is considered in this report to be a future technology, i.e. it is not commercially available today either with or without full guarantees.

4.19.1 Technology description

The biomass fuel is pretreated to obtain a relatively homogeneous size. It is then dried to 10-15% moisture in a dryer where the heating of the drying medium takes place with the residual heat from the plant. The gasification takes place in an atmospheric or pressurised reactor at between 800 and 950 °C. The majority of the particles in the generated gas are separated in a cyclone.

At low pressure gasification, dust is separated in a conventional porous layer dust collector. In a last gas purification stage, gas is scrubbed in a water scrubber that separates ammonia, hydrogen chloride and even tar etc., while the gas is cooled and consequently dried when the water vapour condenses. Scrubbing of course, leads to the need of water management with the purification of the condensate that is formed. For pressurised gasification, tar purification is not necessary if the gas is cleaned of dust at a high temperature at 350-400 °C as the only purification step. In these circumstances, the tars do not condense and they can be burned in the gas turbine. A disadvantage of this method is that ammonia is not separated from gas but forms NO_x from combustion in the gas turbine.

After compression with intermediate cooling, in the case of atmospheric gasification, or directly from the high temperature filter in the event of pressurised gasification, the product gas is burned in the gas turbine combustor. The hot exhaust gases (approximately 450-550 °C) are cooled in a conventional manner in an exhaust gas boiler which, together with gas cooling, generate steam for the steam turbine. [112]

The efficiency from fuel to electricity for BIGCC plants on a large scale is reported to be 42-43% ([127] and [127]). Heating efficiency is expected to be 41-47% of the fuel efficiency and the overall efficiency is 83-90%.

Figure 4-76 shows a schematic arrangement for a BIGCC plant.

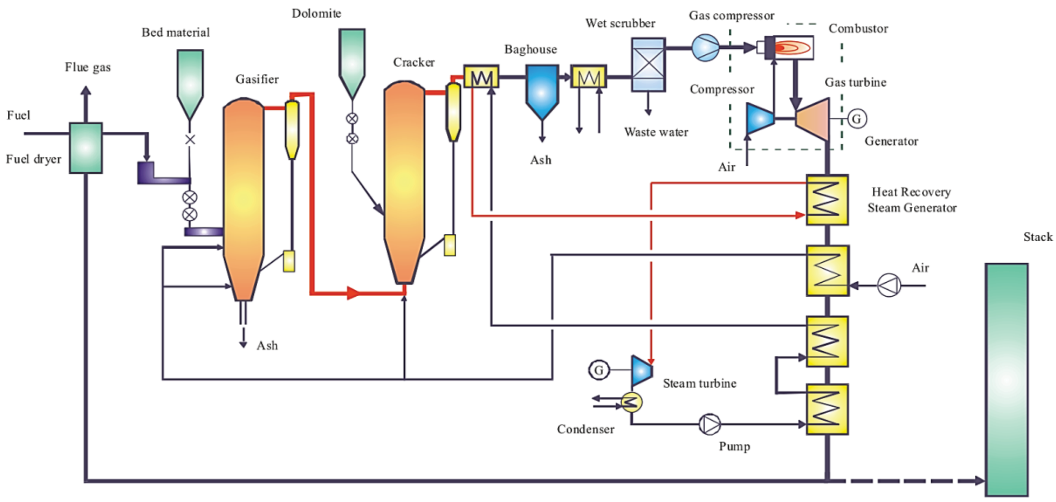

Figure 4-76. Thermal biomass fuel gasification with gas turbine, BIGCC. [112]

4.19.2 Development trends

Some pilot and demonstration plants built in the early 90s - for example, a complete BIGCC plant in Värnamo based on pressurised gasification technology. Despite a technically successful demonstration at the Värnamo plant, no additional plants have been built, and virtually all active development in the area is down since 2004. Gas turbine manufacturers such as Siemens and GE have not been involved in the technology of turbines for about 50-60 MW, whereas the development and demonstration of large gas turbines for similar gas turbines for large coal gasification have taken place. However, studies have also been made in recent years.

Implementation and further development requires interest from the gas turbine manufacturers to actively participate. If so, the new pilot or prototype systems could be implemented in a few years time, after which upscaled/semi-commercial plants would be operational before 2020, and commercial plants will become available in the late 2020s. Gas turbine adaptations usually need major market potential to make them justifiable, which is why the necessary conditions are likely to be that BIGCC in the current sizes are assessed by gas turbine manufacturers to be a long-term technical and economical technology for biomass fuel-based co-generation in both Sweden and other parts of Europe and internationally. This could happen if long-term electricity prices are significantly higher than district heating prices, and if the technology is expected to be applicable to a larger number of district heating bases in appropriate sizes also internationally, in combination with policy instruments that favour biomass fuel-based electricity and district heating production.

However, gasification as a precursor to combustion in an existing (fossil fuel) boiler is more applied than BIGCC. An example is the new biomass fuel gasifier at Vaskiluodon Voima in Finland, which has installed a 140 MW_t gasifier producing gas for the existing carbon boiler of 560 MW_t. Another example is Foster Wheeler's RDF gasifier which supplied an existing carbon boiler in Lahti with a portion of the fuel.

4.19.3 Estimated costs

Investment costs

No commercial BIGCC plants are in operation today. Gustavsson et al. [15] and Wetterlund et al. [127] however, suggests that the cost of a BIGCC plant in the range 40-75 MW of electricity would be between SEK 20,700/kW$_{elec, gross}$ and SEK 22,500/kW$_{elec, gross}$.

The largest ever installed biomass fuel gasifier is the one at Vaskiluodon Voima in Finland which has installed a 140 MW$_t$ gasifier which produces gas for the existing carbon boiler of 560 MW$_t$. The cost of gasifiers and fuel management stood at just under EUR 40 million, which with an electric conversion efficiency of 42.5%, is slightly over SEK 5,700/kW$_{elec, gross}$. In this investigation, a gas turbine power plant has been estimated to cost SEK 11,000/kW$_{elec, gross}$ for a plant with 40 MW of electrical output, which would give a cost for a BIGCC plant of SEK 16,700/kW$_{elec, gross}$. However, the cost of increased gas purification must be added to this figure and the final investment cost may well end up in the region designated by Gustavsson et al. [15] and Wetterlund et al. [127].

Operating and maintenance costs

Gustavsson et al. [15] and Wetterlund et al. [127] specifies fixed operating and maintenance cost of SEK 433 and 675/kW$_{elec, gross}$. The variable operating and maintenance costs amount to about SEK 35 and 32/MWh fuel.

Electricity generation costs

Electricity generation costs have been calculated for a fictitious plant with a gasifier of the same size as that at Vaskiluodon Voima; 140 MW gas. Using the calculation conditions inTable 4-54 (and other non-specified conditions according to the cases for biomass fuel-fired co-generation plant) you get an electricity cost of SEK 0.75/kWh, excluding policy instruments.

Table 4-54. Calculation conditions for BIGCC 66 MW.

Parameters	66 MW	Unit
Specific investment	22,500	SEK/kW$_{elec, gross}$
Fixed O&M	675	SEK/kW$_{elec, gross}$
Variable O&M	35	SEK/MWh$_{elec}$
Efficiency of fuel to gas	90 %	%
Internal electricity consumption	7 %	% of gross electrical output
Electric conversion efficiency	42.5 %	%

4.20 Wave power – Future technology

For future technologies, the report covers development trends and driving forces, technical development and costs as well as critical components together with a brief assessment of technical performance, unlike the commercial and semi-commercial technologies presented in Chapter 4.1 - 4.13 and 4.14 - 4.16 where an electricity generation cost have been presented.

4.20.1 Technology description

A wave power plant converts energy from ocean waves into electricity. There are many different methods, but none is directly superior to any other at the current time. In all probability there will be room for many different methods, especially as conditions vary greatly between different locations with respect to wave climate, water depth, distance to shore etc.

There are six main types of method, all well described by Holmberg et al. [128]; attenuator, point absorber, oscillating surge wave converter, oscillating water column, overtopping device, submerged pressure differential.

The technology that has made the most progress towards commercialisation in Sweden is Seabased AB's point absorber with a linear generator on the seabed. In early 2014, the company's first megawatts were joined to the grid as Sweden's first major wave power farm in Sotenäs municipality [129].

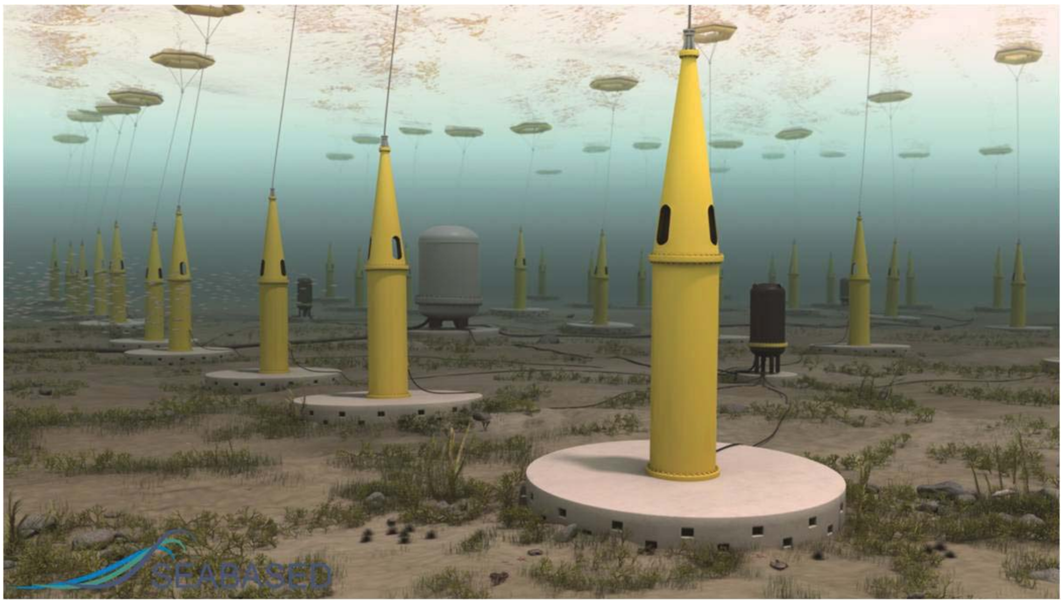

Figure 4-77. Illustration of a wave energy farm from Seabased AB. Source: Seabased [130].

4.20.2 Development trends

According to IPCC [131], there were more than 50 wave power concepts under development in 2011, including more than 10 from companies in the Nordic region when Elforsk [128] signed on in 2011.

Two concepts at the forefront were developed by Swedish Seabased AB and the Scottish company Pelamis Wave Power.

Seabased AB is building Sweden's first and the world's largest wave energy farm in Sotenäs outside of Kungshamn. Permits are in place for 420 units at 25 kW each, meaning the farm will have a total of 25 GWh/year when fully operational [132]. The first stage of a total of about 1 MW will be installed in stages from 2014, while in July 2014 the first units were installed in the farm that will be fully deployed in 2016 [133]. The wave power farm is a research project, mainly funded by Fortum and the Swedish Energy Agency, that is conducted by Seabased AB in collaboration with Uppsala University [134].

The Scottish company Pelamis Wave Power is developing a wave energy that was the first in the world to supply electricity to a grid. Today the recently developed power plant of 750 kW is being tested at several locations outside the UK coast, and the company plans to build a series of production units [135].

4.20.3 Estimated costs

Wave power technology is still under development; there are no established suppliers and costs are only estimates for future plants. In addition, there is a lack of updated summaries for costs for wave power.

Investment costs

A British compilation from 2010 (DECC [136]) indicates the investment cost for a full-scale prototype at SEK 70,000-100,000/kW. An initial wave power plant of 10 MW was assessed in the same compilation to cost between SEK 500-600 million, which is equivalent to SEK 50,000 to 60,000/kW.

Johansson mention at a seminar in 2014 that Seabased's reference plant of 10 MW is estimated to cost SEK 259 million and includes 350 buoys over an area of 64 ha [137]. This corresponds to a specific investment of close to SEK 26,000/kW, which is half of what was presented by Holmberg et al. in 2011 [128].

Operating and maintenance costs

Just as with investment costs, O&M costs are difficult to estimate. A British compilation from 2010 (DECC [136]) estimates the O&M cost for a first wave power plant of 10 MW to between 30 and 40 million per year.

Electricity generation costs

According to Holmberg et al. [128] the electricity generation cost in 2011 is estimated for a first wave power plant of 10 MW at SEK 4.5/kWh, with uncertainties concerning the component costs. In the calculation, a capacity factor of 33%, cost of capital of 12% and an economic lifespan of 20 years. Using the same calculation conditions but with a specific investment cost equivalent to Seabased [137] at SEK 26,000/kW and an O&M cost of SEK 40 million per year, the electricity cost is estimated at SEK 2.7/kWh without electricity certificates.

The *Strategic Initiative for Ocean Energy,* a partnership between businesses and organisations such as the Carbon Trust, Renewable UK and the University of Edinburgh, presented [138] an estimated production cost in 2013 of a second

10 MW farm at between EUR 33 and 62/kWh, which is equivalent to about SEK 2.9 to 5.5/kWh. The calculation has a cost of capital of 12%, and an economic life of 20 years has been used.

British Carbon Trust estimates on its website [139] an electricity cost for a first prototype of wave power of 5 MW at around SEK 4/kWh. Around 2020, they estimate that the cost has dropped to around SEK 2/kWh for sites around the Pentland Firth and Orkney in the UK. The technical and economic conditions have not been reported for the estimates.

5 Results

Chapter 5 contains a summary of results for all technologies in the report. Chapter 4 describes the results of each technology in more detail, here the types of technology are compared with each other. The results are presented for cases with a cost of capital of 6 and 10 % respectively. The influence of the costs of electricity generation from parameters such as cost of capital, depreciation period, investment costs, fuel prices and heat crediting are presented in Chapter 5.3. For more parametric studies we refer you to the web-based calculation application described in Chapter 6.

Figure 5-1 presents the electricity generation cost for all commercial technologies including policy instruments with a 6% cost of capital and as a range for the technologies with multiple output sizes. Further discussion of the results is contained in Chapters 5.1 and 5.2.

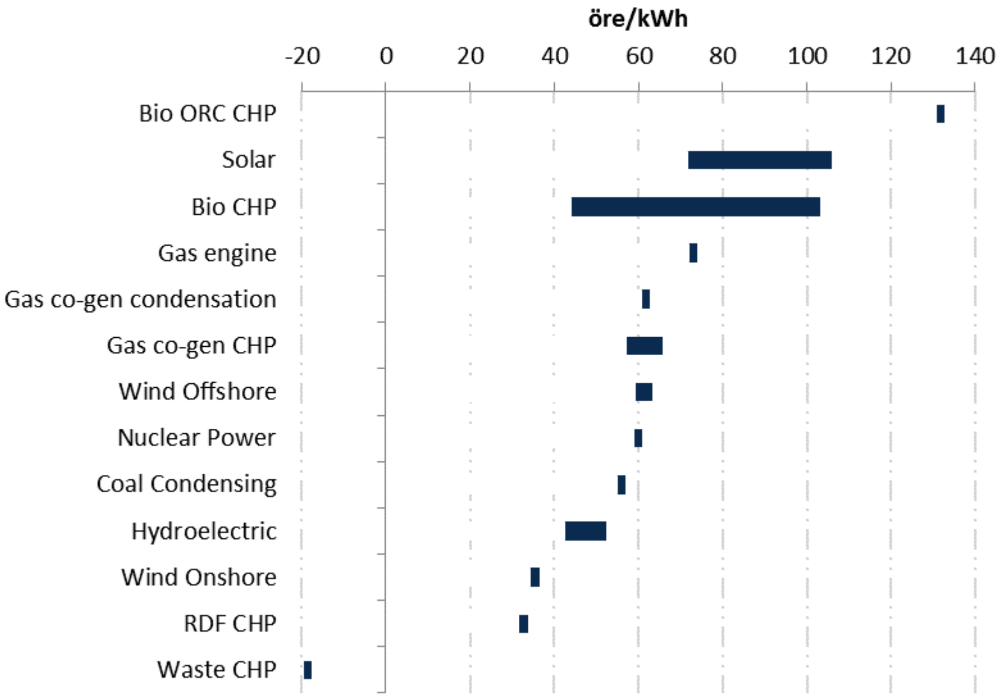

Figure 5-1. Electricity generation costs including policy instruments with 6% interest rate for all commercial types of technology, with a range for the technologies where the electricity generation cost has been calculated for multiple output sizes.

5.1 Commercial technologies

Electricity generation costs for commercial methods are reported inFigure 5-2 - Figure 5-7 and in Table 5-1. The results are discussed in general below.

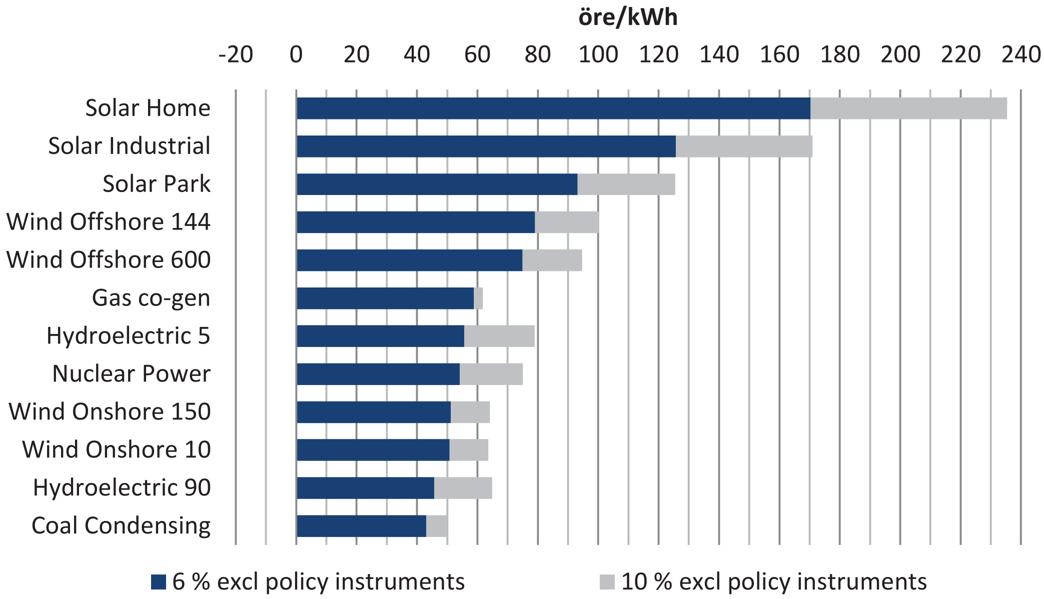

Figure 5-2. The cost of electricity generation for commercial technologies that only generate electricity, excluding policy instruments with 6 and 10% cost of capital respectively.

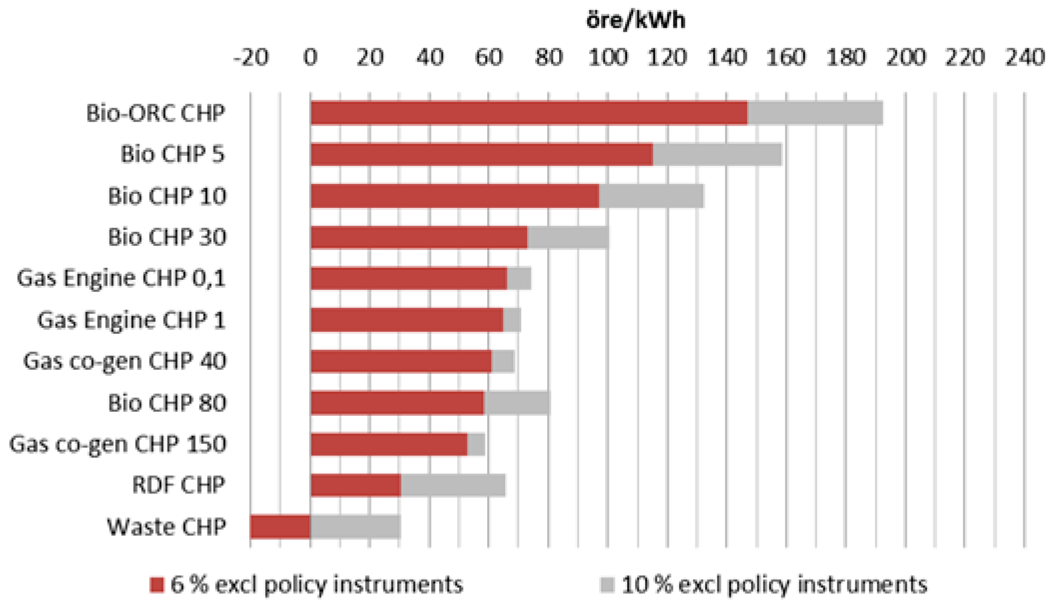

Figure 5-3. The cost of electricity generation for commercial technologies that generate both electricity and heat, excluding policy instruments with 6 and 10% cost of capital respectively.

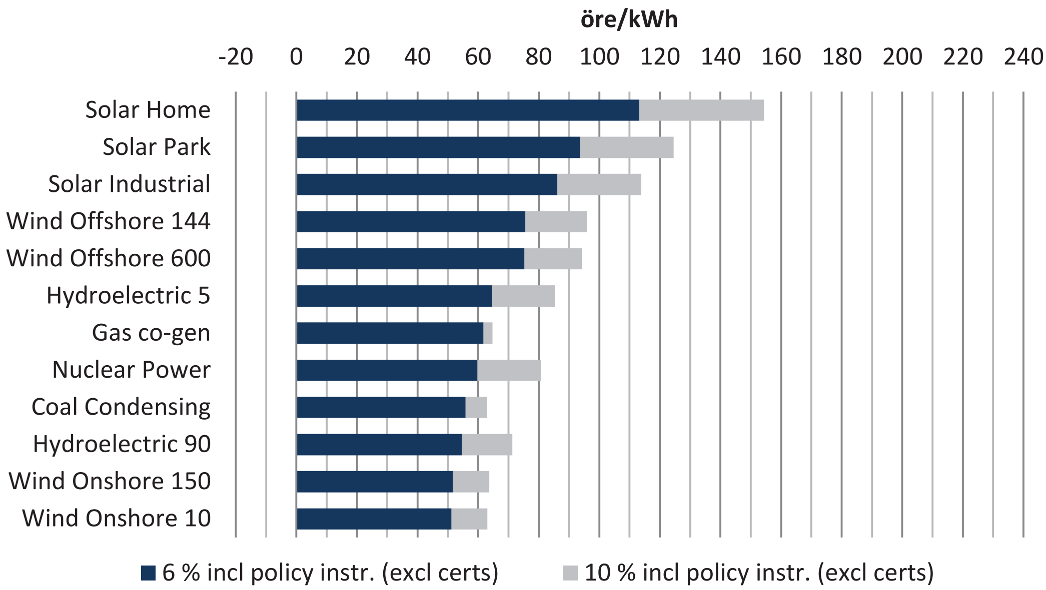

Figure 5-4. The cost of electricity generation for commercial technologies that only generate electricity, including policy instruments but excluding electricity certificates with 6 and 10 % cost of capital respectively.

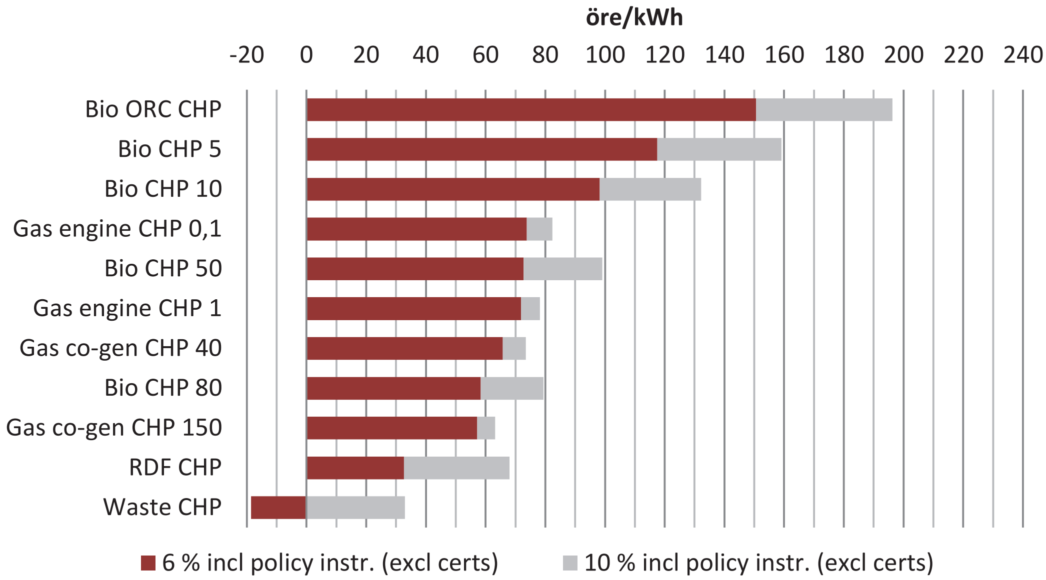

Figure 5-5. The cost of electricity generation for commercial technologies that generate both electricity and heating, including policy instruments but excluding electricity certificates with 6 and 10 % cost of capital respectively.

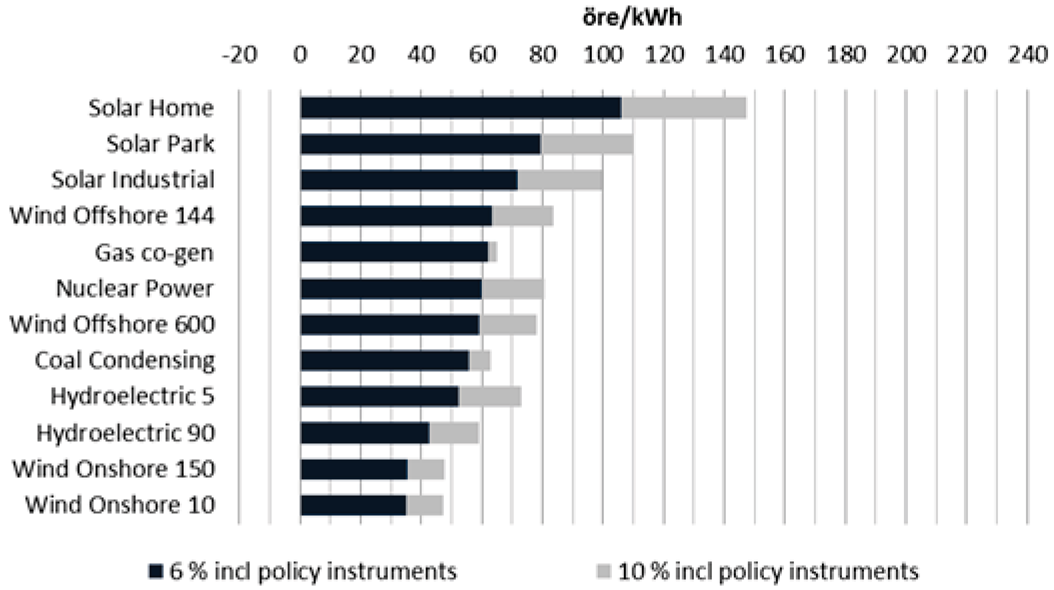

Figure 5-6. The cost of electricity generation for commercial technologies that only generate electricity, including policy instruments with 6 and 10 % cost of capital respectively.

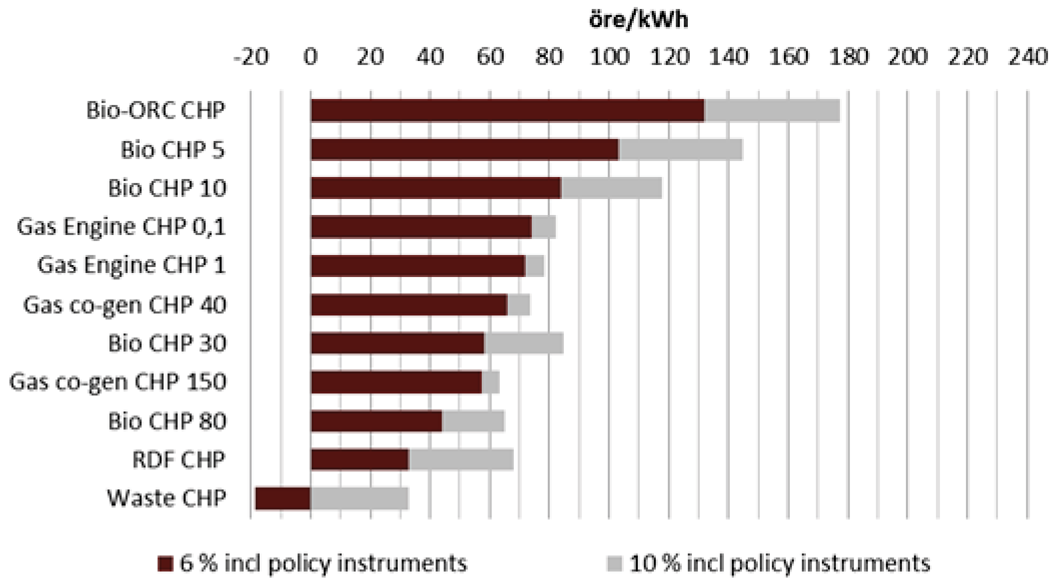

Figure 5-7. The cost of electricity generation for commercial technologies that generate both electricity and heat, including policy instruments with 6 and 10 % cost of capital respectively.

Table 5-1. Electricity generation costs for commercial technologies

Type of technology	Electrical output [MW]gross	Electrical output [MW]net	Electricity generation costs [öre/kWh] With policy instrument 6 % interest	10 % interest	Without policy instruments 6 % interest	10 % interest
Condensing power						
Coal condensing	800	740	56	63	43	50
Gas turbine	151	150	506	662	503	659
Gas co-generation condensation	431	420	62	65	59	62
Nuclear power	1720	1600	60	81	54	75
Co-generation						
Gas co-generation	41	40	66	73	61	69
Gas co-generation	154	150	57	63	53	59
Bio co-generation	5.8	5	103	145	115	159
Bio co-generation	11	10	84	118	97	133
Bio co-generation	33	30	58	85	73	101
Bio co-generation	88	80	44	65	58	81
Waste-fired co-generation	23	20	-19	33	-21	30
RDF co-generation	23	20	33	68	30	66
Gas engine	0.1	0.1	74	82	66	74
Gas engine	1	1	72	78	65	71
Bio-ORC	2.5	2	132	177	147	193
Sun, wind, hydro						
Wind power, onshore	5x2	-	35	47	51	64
Wind power, onshore	50x3	-	36	48	51	64
Wind power, offshore	40x3.6	-	63	84	79	100
Wind power, offshore	100x6	-	59	78	75	95
Hydroelectric power	5	-	52	73	56	79
Hydroelectric power	90	-	42	59	46	65
Photovoltaic (roofs for residential dwellings)	0.005	-	106	147	170	235
Photovoltaic (industry)	0.05	-	72	99	126	171
Photovoltaic (farm)	1	-	79	110	93	125

Uncertainties in costs

The cost of electricity generation is associated with greater uncertainties for certain power sources in the study than others based on the extent of input data available. New nuclear power plants have not been built, for example, in Europe for many years, which means that experiences about costs are few and the cost estimate are therefore more uncertain. In contrast, biomass fuel-fired co-generation plants have been and are being built continuously and extensively in Sweden over recent years, which has generated a lot of supporting data for cost estimates, which are therefore much more certain. New nuclear and hydroelectric power plants are the power sources with the most uncertain costs for electricity generation. All costs and conditions are presented for each power source in Chapter 4, and Chapter 5.3 includes sensitivity analyses that show how the electricity generation cost is affected by the parameters' cost of capital, depreciation, investment costs, fuel prices and heat crediting.

Effects of policy instruments

Economic policy instruments in the form of taxes, fees and electricity certificates affect earnings significantly, which can be compared between Figure 5-2,Figure 5-4 and

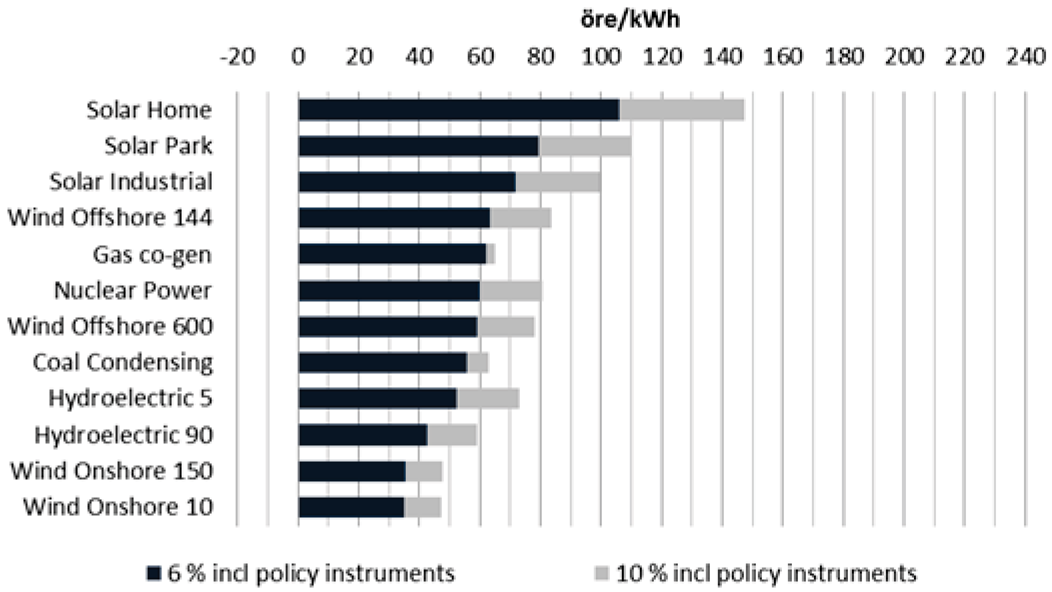

Figure 5-6 for the type of power source that only generates electricity and between Figure 5-3,Figure 5-5 andFigure 5-7 for co-generation technologies that generate both electricity and heat. Generally, fossil fuel power sources are penalised while renewable power sources are favoured. Clear examples where policy instruments have a major effect on electricity generation costs are wind power and coal condensing. Note that taxes and fees related to the management of residual waste from nuclear power and waste tax for other technologies (also known as landfill tax) have been included in the O&M costs as detailed in Chapter 3.8, these taxes and fees are also included in those cases where electricity generation costs are presented excluding policy instruments.

Discussion on the performance of commercial technologies
Waste-fired co-generation has the lowest electricity generation costs of all component technologies in the study. This is mainly because the fuel, both household and industrial waste, does not have a cost but a benefit, while the percentage of heat generated is very high, which generates significant revenue through heat crediting. It is important to note that waste-fired co-generation is primarily being built to generate heat and therefore require a local demand for heating. Without heat crediting, the electricity generation cost would be very high, above SEK 1.30/kWh, which would instead make waste-fired co-generation as one of the most expensive types of technology in the study.

Of the technologies that only generate electricity, coal condensing has the lowest electricity generation costs, where the calculation is performed without any economic policy instruments. When policy instruments are added, coal condensing is more expensive and onshore wind power has the lowest electricity generation cost, even before electricity certificates are included. Apart from the waste-based co-generation technologies, onshore based wind power has the lowest electricity generation costs with current policy instruments. However, note that any costs for power regulation have not been addressed in this report.

Biomass fuel-fired co-generation show a clear size dependence where the electricity generation costs are lower the larger the plant is. Also here, it is important to point out that biomass fuel-fired co-generation plants are fundamentally dependent on a heat source and that heat crediting is key for the electricity generation cost.

According to Figure 5-2,Figure 5-4 and

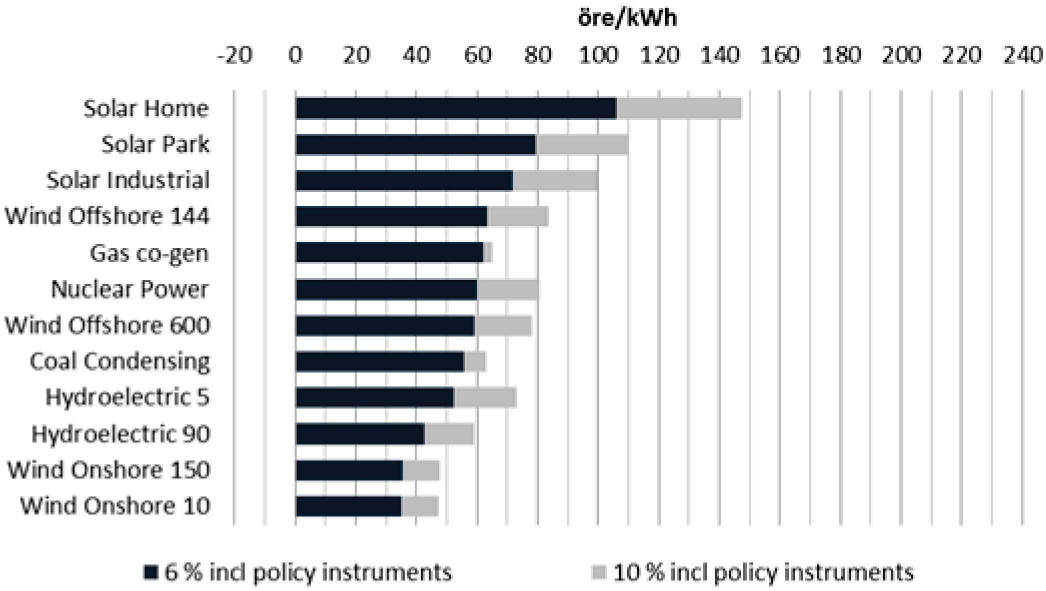

Figure 5-6 wind power shows no clear size dependence between different plant sizes. It should be clarified that the cost of wind power is dependent on size for comparisons in one specific place. The reason for this size dependence not being evident in Figures Figure 5-2,Figure 5-4 and

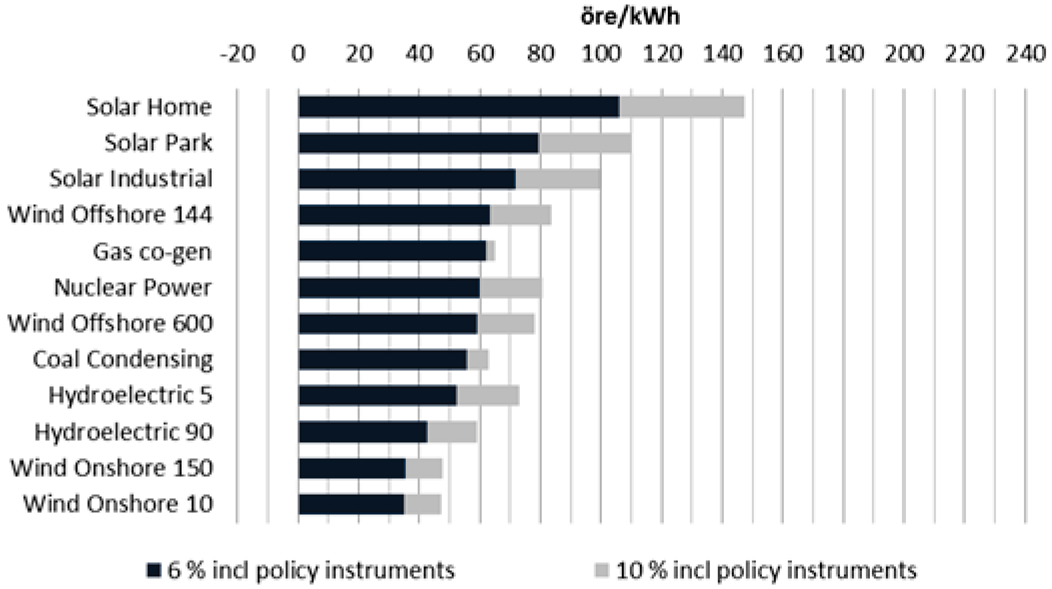

Figure 5-6 is that the electricity generation costs displayed will not have been calculated for the same specific place but is based on average costs for new wind power plants. Smaller plants are usually built near to the power grid and where the wind conditions are good, whereas larger plants are often further away from the power grid and experience less favourable wind conditions. The various preconditions that plants have mean therefore that size dependence which is evident at the exact same place does not appear. However, the difference between onshore and offshore wind power is significant in the report.

The electricity generation costs of photovoltaic power plants have fallen significantly in recent years as a result of increased efficiency and decreasing investment costs for solar panels.

5.2 Semi-commercial technologies

Electricity generation costs for semi-commercial techniques are reported in the Figure 5-8 - Figure 5-10 and in Table 5-2. The results are discussed in general below.

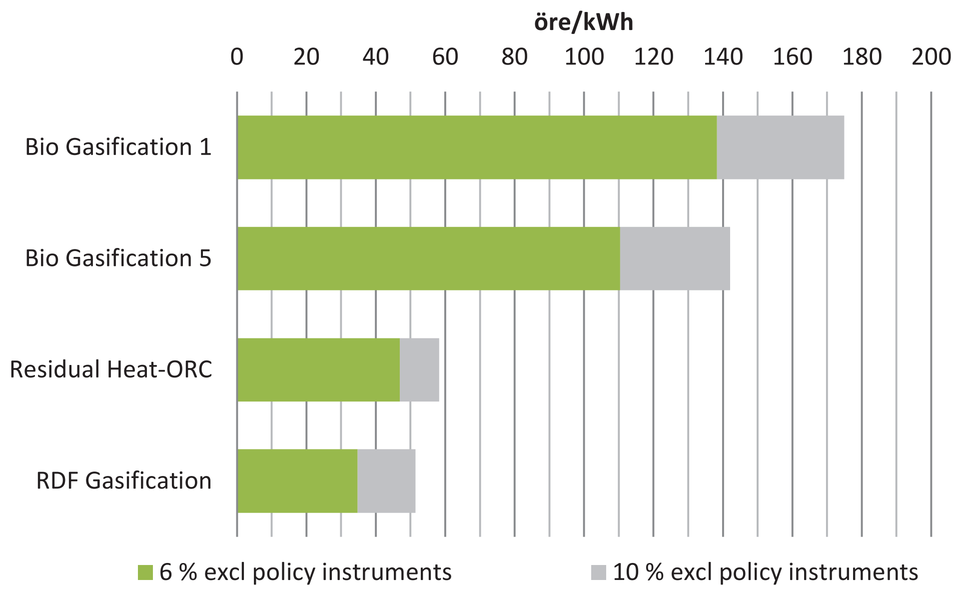

Figure 5-8. Electricity generation costs for semi-commercial technologies, excluding policy instruments with 6 and 10 % cost of capital respectively

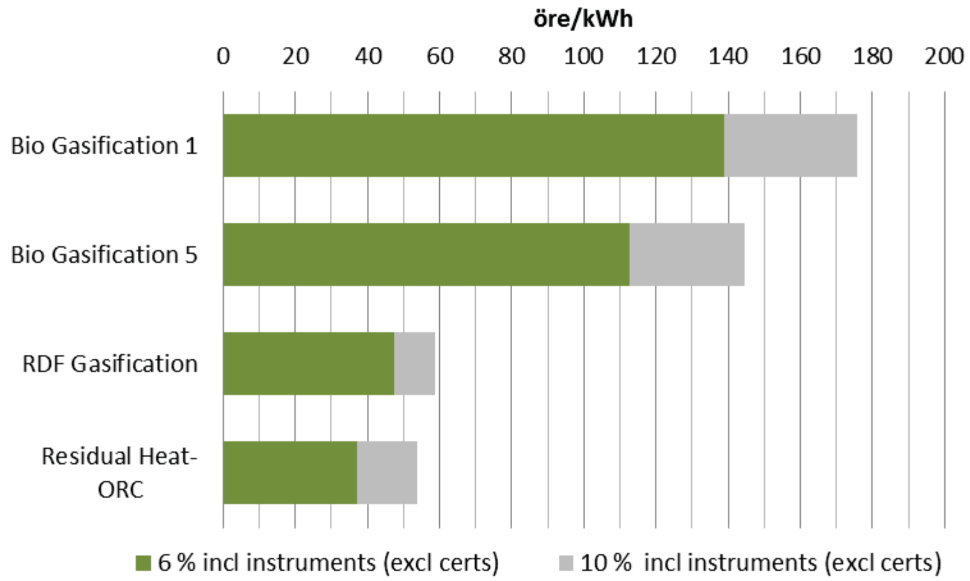

Figure 5-9. The cost of electricity generation for semi-commercial technologies, including policy instruments but excluding electricity certificates with 6 and 10 % cost of capital respectively.

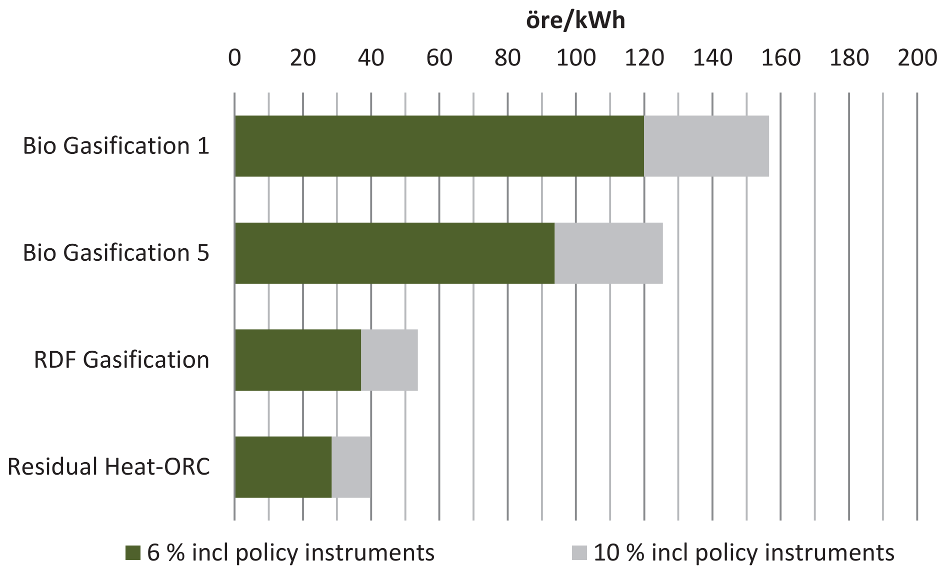

Figure 5-10. Electricity generation costs for semi-commercial technologies, including policy instruments with 6 and 10 % cost of capital respectively

Table 5-2. Electricity generation costs for semi-commercial technologies

			Electricity generation costs [öre/kWh]			
			With policy instruments		Without policy instrument	
Type of technology	**Electrical output [MW]gross**	**Electrical output [MW]net**	**6 % interest**	**10 % interest**	**6 % interest**	**10 % interest**
Residual heat-ORC	0.8	0.5	28	40	47	58
RDF gasification	56	50	37	54	35	51
Biomass fuel gasification	1.1	1	120	157	138	175
Biomass fuel gasification	5.8	5	94	125	110	142

Uncertainties in costs

As defined in this report, semi-commercial technologies are new, and can probably be purchased with limited warranties. This means that the supporting data for the costs is limited while the calculation assumptions are based on expectations, particularly for operating time and availability.

Effects of policy instruments

The electricity certificate is the most important instrument among the semi-commercial power sources that reduce the cost of all of them except for RDF gasification which is not entitled to electricity certificates. Other policy instruments only affect the electricity generation costs marginally. Note that waste tax (also known as landfill tax) has been included in the O&M costs under Chapter 3.8. This includes waste tax even where electricity costs are presented excluding policy instruments.

Discussion on the performance of semi-commercial technologies
The electricity generation costs including policy instruments for a waste heat driven ORC plant are some of the lowest in the report, provided that free residual heat with a sufficiently high temperature is available throughout the year and at an availability rate of 95%. The technology is still in its infancy, and experiences from plants in operation provide an availability rate today that is well below 95%, which probably means that the O&M costs are also higher than assumed. The report considers that residual heat has originally come from a renewable fuel which entitles electricity certificates.

The electricity generation costs for biomass fuel gasification with gas engine (BIG ICE) are heavily linked to the size of the plant. The smaller plant of 1 MW has a higher capital cost per installed kW_{elec} and an electric conversion efficiency below 5 MW per plant which leads to almost 50% higher electricity generation costs for the smaller plant than the larger one. Compared to the 5 MW biomass fuel-fired co-generation power plant, the electricity generation costs are lower due to lower investment costs and the higher electric conversion efficiency of the gasification-based plant. The gasification plant works with lower quantities of air and is therefore more compact than a corresponding gasification plant. Despite this, the technology has yet to take hold in Sweden. The reason for this may be the maturity of the technology especially regarding gas purification. With increasing positive experiences from the technology, the economic calculation should improve through a longer depreciation period etc.

RDF gasification has a relatively low investment cost per installed kW compared to other solid-fuel-fired power plants while the electric conversion efficiency is higher. Along with a low fuel cost, this provides low-cost electricity. However, the technology is in its development stage and the generation cost calculation is based on an availability on par with other waste-fired power plants and Kymijärvi I (>95%). However, at Kymijärvi I the gas is fired immediately without purification. At Kymijärvi II the gas is purified before the burners which, among other things, can lead to condensation of the tar. The availability and maintenance cost is therefore somewhat uncertain in this calculation.

All of the semi-commercial technologies except Residual heat-ORC are both electricity and heat producing power sources allowing heat crediting, and therefore the provision of heat has a major impact on electricity generation costs for these technologies.

5.3 Sensitivity analyses

Sensitivity analyses are made below from the parameters' cost of capital, depreciation period, investment costs, fuel prices and heat crediting for selected commercial power sources that are significantly affected by each parameter. You can perform your own sensitivity analyses using the calculation application described in Chapter 6.

5.3.1 Cost of capital

The cost of capital which is reasonable for each type of technology varies according to the investment's risk and return requirements of investors. In this report, the electricity generation costs presented in Chapter 4 have been developed with an assumed common cost of capital of 6%, which is described in Chapter 3.10. For all power sources, the electricity generation cost is presented as 10% of cost of capital in Figure 5-2 - Figure 5-7 and inTable 5-1 and Table 5-2. Technologies that are associated with high investment costs and high risks probably require a higher cost of capital for an investor to make an investment, such as nuclear power for example. For small-scale technologies such as the “solar house” option, a lower cost of capital can probably be applied.

The photovoltaic type of technology is among the capital-intensive technologies that are most affected by the cost of capital as per Figure 5-11, the cost of electricity generation varies between SEK 0.64 and SEK 1.28/kWh for a cost of capital of 2 and 10% respectively.

Onshore wind is least affected by the cost of capital among the capital-intensive technologies where the electricity generation costs vary between SEK 0.40 and SEK 0.65/kWh for a cost of capital of 2 and 10% respectively.

For other capital-intensive technologies, the electricity generation costs will increase by about SEK 0.20/kWh when the cost of capital is increased from 6 to 10%.

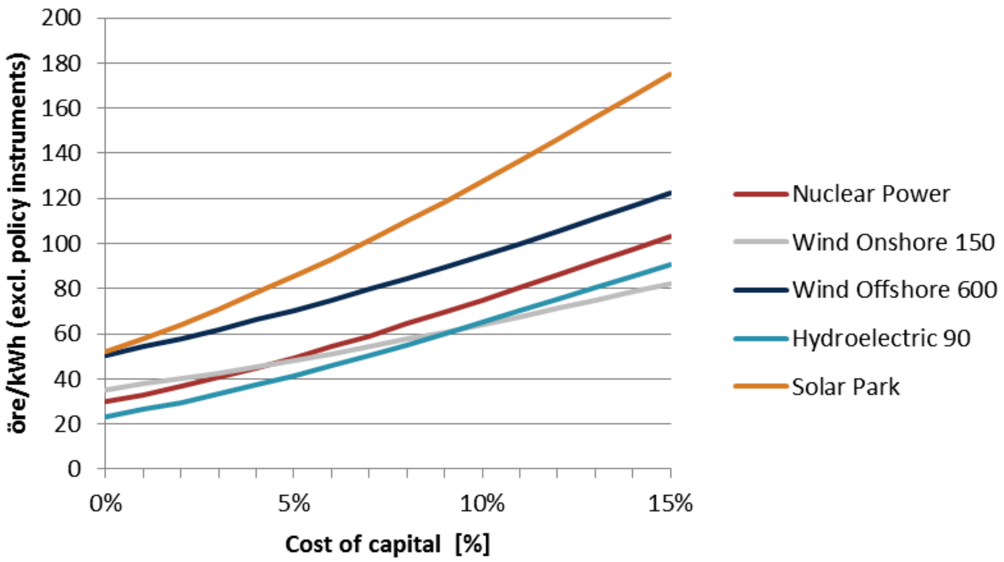

Figure 5-11. The impact of the cost of capital on electricity generation costs excluding policy instruments for some of the capital intensive technologies

5.3.2 Depreciation period

The economic life (depreciation) of the plants is presented for all power sources in Chapter 3.10.

The electricity generation costs increase exponentially with decreasing depreciation, for the capital-intensive power sources in the study there is a clear increase for depreciation periods above 15 years according to Figure 5-12. However, the influence of the depreciation period on the electricity generation costs reduces through an increased depreciation period and for depreciation periods between 25 and 40 years this gives a reduction in the electricity generation costs of about SEK 0.07/kWh for the studied power sources except for solar power which decreases by about SEK 0.13/kWh.

The electricity generation costs for onshore wind power, which in the study are calculated using a depreciation period of 20 years, should, according to some in the industry be calculated today using a depreciation period of 25 years with the latest technological and economic developments. However, in this study, the electricity generation costs differ by less than SEK 0.04/kWh between 20 and 25 years in depreciation period, and only just over SEK 0.02/kWh between 25 and 30 years in depreciation period. Increased depreciation periods over 20 years, do not have a lot of effect on the ultimate cost of electricity generation.

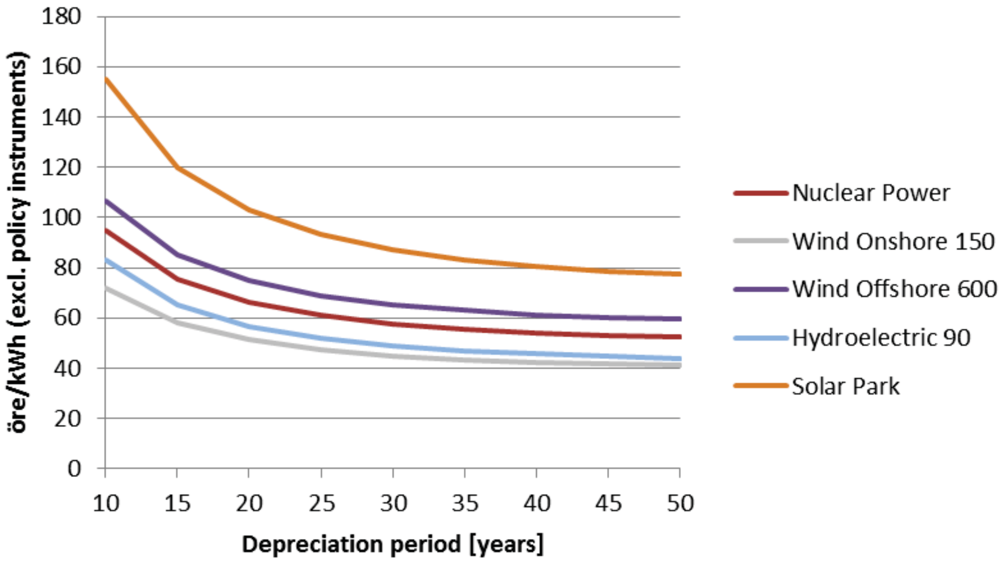

Figure 5-12. The impact on fuel prices from the depreciation period excluding policy instruments for some of the fuel based technologies. The depreciation set in the report; nuclear and hydroelectric power 40 years, solar power 25 years and wind power 20 years.

5.3.3 Investment cost

Some investment costs in the report are associated with major uncertainties, such as for current nuclear and hydroelectric plants according to discussions in Chapter 4.4.4 and 4.12.4. Figure 5-13 shows how the electricity generation cost is affected by the investment cost for some of the capital-intensive technologies. Solar power and offshore wind is most affected. If the investment cost changes by 20%, the electricity generation costs will change by SEK 0.17

and SEK 0.12/kWh respectively. Other capital-intensive power sources are affected about the same, if the investment cost changes by 20%, the electricity generation costs change by about SEK 0.08/kWh. The higher the proportion of capital costs, the greater the impact.

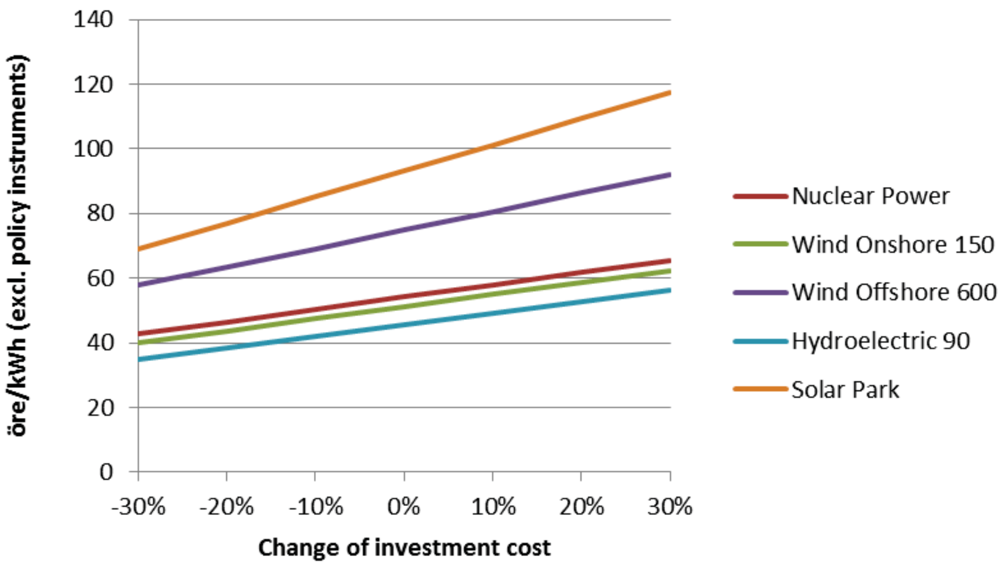

Figure 5-13. The impact of the investment cost on electricity generation costs excluding policy instruments for some of the capital intensive technologies

5.3.4 Fuel price

For the power sources that are fuel-based, the fuel prices have a major impact on the electricity generation cost. Coal condensing is the least affected of the studied power source according to Figure 5-14, if the coal prices change by 20%, the electricity generation costs change by about SEK 0.04/kWh. Natural gas engine and waste-fired co-generation are affected most among the studied power sources; a change in the natural gas price of 20% changes the electricity generation costs by gas engine by SEK 0.16/kWh, if the price of waste changes by 20% the electricity generation costs change by less than SEK 0.14/kWh.

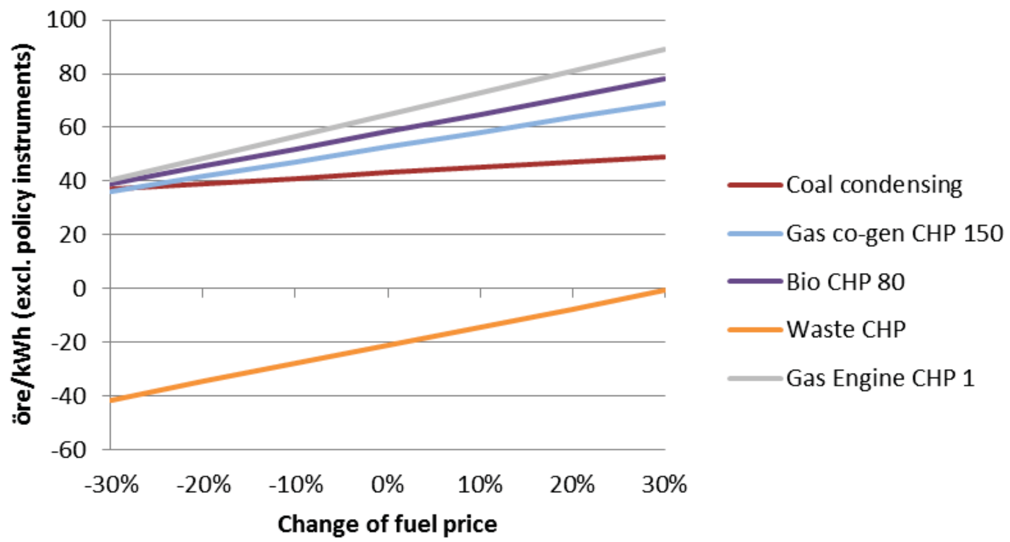

Figure 5-14. The impact on fuel prices from electricity generation costs excluding policy instruments for some of the fuel based technologies

5.3.5 Heat crediting

In a co-generation power plant, where electricity and heat are generated simultaneously, the co-generated and usable heat must be attributed a value when calculating, i.e. all the costs of generation in the co-generation power plant cannot be attributed to the generation of electricity. This report estimates the cost of electricity generation for co-generation power plants by subtracting the cost of producing district heating from the total generation costs for producing both electricity and heat. The methodology is described in detail in Chapter 3.6.2.

Heat crediting affects the electricity generation costs for co-generation significantly, especially for technologies with low electric conversion efficiency such as Bio-ORC and waste-fired co-generation according toFigure 5-15; both with electricity efficiencies below 20 %. If heat crediting increases by 20% this reduces the resulting electricity generation costs of Bio-ORC by about SEK 0.42/kWh, from SEK 1.47 to SEK 1.05/kWh. Heat crediting can be changed freely in the calculation application described in Chapter 6.

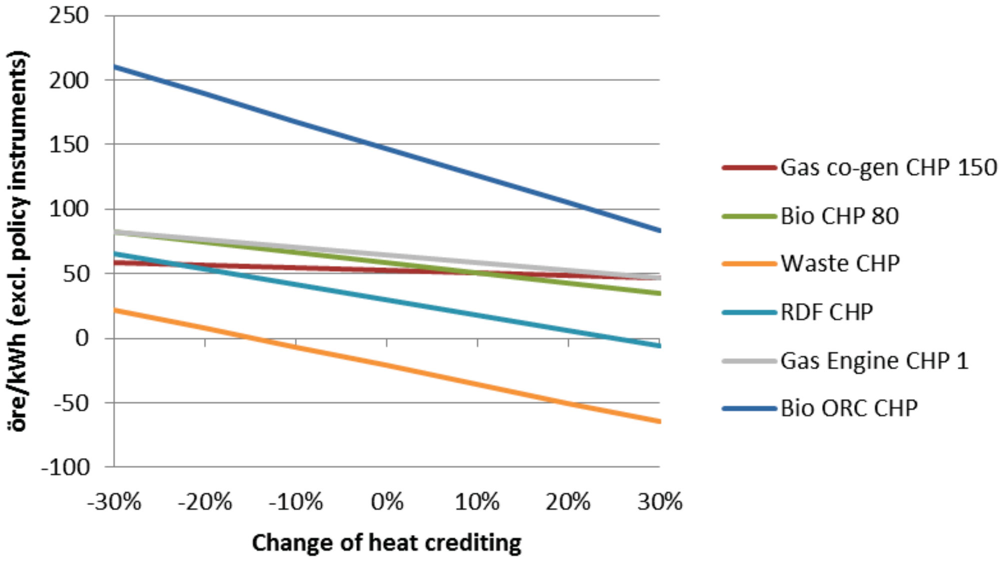

Figure 5-15. The impact of fuel prices on electricity generation costs excluding policy instruments for some of the fuel based technologies

5.3.6 Summary of sensitivity analyses

Electricity generation costs presented in this report are based on many assumptions about everything from plant size and specifications to the economic conditions in order to obtain a general and comparable picture of what it costs to generate electricity using a range of technologies.

In Chapter 5.3 only a few economic parameters vary at a general level. In order to examine a specific case, both in terms of plant-specific parameters and economic conditions, the calculation application described in Chapter 6 is used.

6 Web-based calculation application

6.1 General

The calculation application, which is available on Elforsk's website http://www.elforsk.se, calculates the electricity generation costs for specified plant options according to the annuity method with pre-specified input data. The calculation results are presented in tabular and graphic format and, together with the associated input table, are exported to Excel format. The user specifies which of the plants are to be included in the calculations, and can freely modify the input data for each plant option.

This report serves as an “instructions manual” and source references for how the calculation application should be used, how the results should be interpreted and where preset input comes from.

6.2 Use of calculation application

The calculation application is available on the Elforsk website http://www.elforsk.se and can be used with modern browsers from Internet Explorer 9 and onwards.

The workflow in the application is as follows;

1. **Selection of plants**
   The plants that are to be included in the calculations are selected by ticking the boxes for each plant. All plants in one category can be selected by clicking on the “All of the above” button.

2. **Parameters**
   All the parameters that form the basis of the calculations are completed in advance for each plant option, the majority can be modified freely by changing the entry fields[34]. All input data can be reset to the default for each plant option by clicking the “Restore” button. The input table can be exported to an Excel file by clicking “Download table”.

3. **Results**
   The results are reported in table form for each plant. The results table can be exported to an Excel file by clicking “Download table”.

4. **Chart**
   The results can be visualised in a number of charts by clicking “Create

[34] If input data is modified by the user, the other input does not necessarily apply any more and the calculation may be inaccurate. If, for example, a plant size is changed this is not necessarily the predefined specific investment cost that was worked out for a specific plant size.

chart". All charts can be saved by clicking the "Save as Image" button under each chart.

6.3 Explanation of the calculation application

All pre-specified input data and nomenclature for the plants are given for each plant option in Chapter 4 in the report. General conditions and explanations, such as what taxes are to apply or what is generally included in the investment cost, are described in Chapter 3.

6.3.1 Related parameters

The calculation includes all project-specific costs and revenues along with the economic policy instruments for 2014.

The following costs have been taken into account in the calculations;

- Annuity calculated cost of capital with respect to interest over the construction period
- Fixed operation and maintenance costs
- Variable operating and maintenance costs including landfill cost of fuel ash
- Fuel costs
- Present value of estimated future reinvestment costs
- Location specific costs
- Economic policy instruments
    - Energy tax
    - Carbon tax
    - Sulphur tax
    - Power tax (nuclear power)
    - Property tax
    - NO_x fees
    - Emission rights for CO_2

The following revenues have been taken into account in the calculations;

- Heat crediting
- NO_x repayment
- Presently estimated value of electricity certificates
- Investment grants
- Variable income

Location-specific costs are indicated for each plant. These can be specified either as a one-time charge, an annual cost or a variable cost. Variable revenue can also be specified. These items are input, for example, for possible future policy instruments or existing plant specific cost items.

6.3.2 Presentation of results

The results of the calculations are presented in both tabular and graphic format. In addition to the results for the specified parameters, a number of charts are generated with sensitivity analyses to show how the results are affected by changes to the cost of capital, depreciation, investment costs, fuel prices and heat crediting.

6.4 Simplification of calculation application

For the application to be manageable, a certain simplification of the parameters and calculations has been made.

6.4.1 Explanation of the electricity output

Electricity output for solar, wind and hydroelectric power
The reported electricity output and specific costs are based on gross electrical output, for wind power and hydroelectric power this is better known as the rated output or generator output and for solar power it is better known as peak output – SEK/kW_{elec}, which means SEK per gross electricity output.

Electrical output for other power sources
The reported electrical output, electric conversion efficiency and specific costs for the remaining power sources, unless otherwise indicated, are based on net electricity generation, i.e. internal electricity consumption in the plant is run from the generated electricity output – SEK/kW_{elec}, which means SEK per net electricity output[35].

[35] The net electricity output is to represent a resulting average output over the year, less internal losses/consumption and partial load output; as a simplification in the calculations the maximum net power output has been used.

6.4.2 Heat output including flue gas condensation (RGK)

The calculation application is simplified in order to estimate the total heat output including RGK and with a net alpha value defined as the ratio of net electric power and heat output including RGK. In cases where a plant has RGK, the RGK output amounts to 20% of the plant's thermal output by default.

6.4.3 Electric conversion efficiency of co-generation

For the constituent co-generation plants, electric conversion efficiency has been calculated from the specified net electric output, heat output (including RGK) and total efficiency through the connection;

$$\eta_{el} = \eta_{total} \cdot \left(\frac{1}{1 + \frac{1}{\alpha_{net}}} \right)$$

where α_{netto} is the ratio of net electric power and heat output (including RGK). To avoid electric conversion efficiency increasing to an unreasonable level for a reduction in heat output, a limitation has been added; at reduced heat output from the default, the electric conversion efficiency is kept constant, which in practice means that total efficiency decreases. A limit is missing for unreasonably high electric conversion efficiency for unreasonably overstated net electrical output, but the discerning user is prompted to handle this.

6.4.4 Cost of fuel for nuclear power

Unlike other condensing power methods, the electric conversion efficiency of nuclear power is defined as the ratio of net electric power and thermal output, which means that the differences in electric conversion efficiency does not affect fuel consumption in the calculation application. The electric conversion efficiency for nuclear power is fixed at 36% instead, and the fuel cost is given instead per electricity, öre/kWh$_{elec.}$

6.4.5 Interest during the construction period

Interest during the construction period is calculated based on an assumed payment plan for each plant. In the application, the payment plan can be freely altered up to 10 years prior to the start of operation for all plants.

The payment schedule is simplified in that it is based on the entire year. For technologies with short construction times and constructed and put into operation at 1 year of completion at the end of the year (year 0), a more accurate picture could be provided with quarterly breakdowns. For long construction times, this has less importance. In order to get a reasonable reflection of the real situation, within the framework for the selected division for the full year, especially the plants with short construction times, these have been assumed to have a larger proportion of payments that are less than the year in which the plant was put into operation (year 0).

6.4.6 Electricity certificates

An electricity certificate is income that reduces the need for electricity sales revenue in order to cover the costs of electricity generation. For the calculations, a price of SEK 190/MWh has been set as default. Payments are made over 15 years with the present value being calculated and is distributed in accordance with the annuity method over the useful lifespan.

Readings from electricity generation for electricity certificates can be made based on gross or net electricity, i.e. including or excluding auxiliary power (own use of electricity in power plants). As a simplification of the calculations, readings are assumed to be made based on net electricity generation instead of gross electricity generation, resulting in a decrease in revenue.

7 Comments

In this 2014 edition of “Electricity from new and future plants” cost estimates for the 14 commercial and 3 semi-commercial power sources have been conducted. For several of the power sources, different plant sizes have been evaluated. In total, 28 different cases have been handled. In addition, development trends and rough cost estimates for electricity generation using four different future technologies have been examined in this report.

To make it possible to compare electricity costs in this report with the derived Swedish electricity generation costs for new plants in 2011 [1], the selection of power sources and plant sizes for the most part has remained the same. Certain power sources have disappeared and some have been added. Changes to plant sizes have been adjusted whenever it was warranted because of technological advances etc. For wind power, one instance has been deleted (onshore wind power 1MW) and plant sizes and/or unit sizes have been adjusted in three of the four instances. For photovoltaics, two instances have been added; 5 kW (“roofs for residential dwellings”) and 1,000 kW (“farm”). The Bio-ORC and Photovoltaic power sources were regarded as semi-commercial in 2011, but in 2014 they were considered to be commercial. The selection of power sources and plant sizes has been made in consultation with the project Steering Group. Furthermore, the trends have been described for the different power sources but any forecasts for how electricity costs are expected to develop over the next 20 years have not been presented.

The study also includes the calculations for the electricity generation cost of a gas turbine of the size 150 MW_{net}. This plant has been included in the work to represent an output producer as a regulating power for electricity generation from solar and wind power with very short operating times (100h/year). The justification is to indicate what regulating power could cost with so few hours of operating time in the event Swedish hydroelectric power would not be enough to balance the power demand.

The basis for cost estimates and the calculation model for calculation of electricity generation costs have been developed from scratch in this project. In addition, a new web-based calculation application for calculating electricity generation costs has been developed in the project. The calculation application has been developed for the individual plant owner or the reader who wants to adapt certain conditions or input data, or is interested in conducting more detailed sensitivity analyses than those presented in the report. Examples of input data that may need to be adapted to suit different conditions are interest rates, which vary with the power source, risk assessments and ownership structure.

This report compares the cost of generating electricity in power plants with the cost of generating electricity in co-generation plants. For co-generation plants as well as power plants, the entire cost of generation has been allocated to electricity. The district heat generated is then credited for co-generation plants.

It is crucial to point out that the main purpose of the co-generation plant is to generate district heating and that possible electricity generation depends on how the heat source for the co-generation plant is spread over the year and if the boiler is the base load or peak load in the district heating system. The size of heat crediting has a great significance for electricity generation costs for co-generation plants, and especially when the alpha value is low, such as for: waste-fired co-generation plants, biomass fuel co-generation with ORC technology and smaller bio-fired co-generation plants. For waste-fired plants, in addition to heat crediting, the reception charge also has a great importance on the power generation costs which are the lowest in the report. However, waste plants are not being built to generate electricity in the first hand, but to recover energy from waste and district heating.

Finally, the accuracy of the figures and data presented in this report varies. This is mainly because the experiences from recent investments is unavailable for certain technologies, such as nuclear power and coal condensing power. In addition, there are large differences between the power sources when it comes to the possibility of generalising the preconditions for a typical plant, such as hydroelectric power where the investment cost may vary greatly depending on the geographical conditions. The calculation conditions and results presented in Chapters 4 and 5are generally specified as integers or with a decimal point, regardless of the number of significant digits or the accuracy contained in the figure. This is to provide clarity and make it easier for the reader to follow the calculations.

8 Literature

[1] O. Nyström, P.-A. Nilsson, C. Ekström, A.-M. Wiberg, B. Ridell och D. Vinberg, ”El från nya och framtida anläggningar 2011,” Elforsk, Stockholm, 2011 (Elforsk Rapport 2011:26).

[2] Energimyndigheten, ”Energiläget 2013,” Eskilstuna, 2014 (ET 2013:22).

[3] SCB, ”Trädbränsle- och torvpriser Nr 1 2014,” Energimyndigheten, Eskilstuna, 2014.

[4] Energimyndigheten, ”Energimarknadsrapport olja, gas, kol - Vecka 15,” Energimyndigheten, Eskilstuna, 2014.

[5] Energinet.dk, ”Betalinger for transport i gastransmissionsnettet,” 11 februari 2014. [Online]. Available: http://energinet.dk/SiteCollectionDocuments/Danske%20dokumenter/Gas/Prisblad%20pr%20%2011%20%20februar%202014%20DK.pdf. [Used 3 May 2014].

[6] Profu, ”Bränsleutredningar 2013,” 2013. [Online]. Available: http://www.profu.se/pdf/mavg2013.pdf. [Used 28 August 2014].

[7] Dong Energy, ”Naturgaspriser,” 3 Maj 2014. [Online]. Available: http://www.dongenergy.dk/erhverv/energimarked/Pages/naturgaspriser.aspx. [Used 3 May 2014].

[8] Göteborg Energi, ”Naturgasnät - gasnätpriser 2014,” [Online]. Available: http://www.goteborgenergi.se/Foretag/Produkter_och_tjanster/Gas_/Gasnat. [Used 3 May 2014].

[9] World Nuclear Association, ”Economics of Nuclear Power,” Februari 2014. [Online]. Available: http://www.world-nuclear.org/info/Economic-Aspects/Economics-of-Nuclear-Power/. [Used 18 February 2014].

[10] H. Hansson, S.-E. Larsson, O. Nyström, F. Olsson och B. Ridell, ”El från nya anläggningar 2007,” Elforsk, Stockholm, 2007 (Elforsk Rapport 2007:50).

[11] M. Bärring, O. Nyström, P.-A. Nilsson, F. Olsson, M. Egard och P. Jonsson, ”El från nya anläggningar - 2003,” Elforsk, Stockholm, 2003 (Elforsk Rapport 2003:14).

[12] M. Bärring, J.-O. Gustafsson, P.-A. Nilsson, H. Ohlsson och F. Olsson, ”El från nya anläggningar,” Elforsk, Stockholm, 2000 (Elforsk Rapport 2000:01).

[13] Elforsk, ”Elforsk Anläggningskostnadsindex,” 19 Mars 2014. [Online]. Available: http://www.elforsk.se/Global/Vattenkraft/filer/Anlaggningskostnadsindex/VAST-IND_2_2013_diagram_tabell.pdf. [Used 26 June 2014].

[14] B. Karlsson, ”Södras skogsbränsle - GROT-uttag med näringsåterföring,” i *Askdagen, Värmeforsk*, Stockholm, 2014-05-09.

[15] L. Gustavsson, L. N. Truong, A. Dodoo och R. Sathre, ”Effects of environmental taxation on district heat production structures,” i *World Renewable Energy Congress*, Linköping, 2011.

[16] J. Bergström och L.-M. Johansson, ”Jämförelse av livscykelkostnad för värmeproduktionssystem i flerbostadshusområde,” Examensarbete 2005:59, Chalmers tekniska högskola, Göteborg, 2006.

[17] Miljöorganisationernas kärnavfallsgranskning, ”SKB skickar uppskattningar av framtida avfallskostnader till SSM,” 7 Januari 2014. [Online]. Available: http://www.mkg.se/skb-skickar-uppskattningar-av-framtida-avfallskostnader-till-ssm. [Used 6 March 2014].

[18] G. Åhrling, Personal communication, *Fastighetsskatt för elproduktionstekniker, Svensk Energi.* 25 February 2014.

[19] Naturvårdsverket, ”Verksamheter som ingår i EU:s system för handel med utsläppsrätter,” 18 Februari 2014. [Online]. Available: http://www.naturvardsverket.se/Stod-i-miljoarbetet/Vagledningar/Utslappshandel---vagledningar/Utslappshandel-verksamheter-som-ingar/. [Used 25 April 2014].

[20] Naturvårdsverket, ”Naturvårdsverkets och Regerings tolkning av varför rena biobränsleanläggningar kan ingå i handelssystemet,” 15 Februari 2013. [Online]. Available: http://www.naturvardsverket.se/upload/stod-i-miljoarbetet/vagledning/utslappsratter/verksamheter-som-ingar/biomassaanlaggingar.pdf. [Used 25 April 2014].

[21] Energimyndigheten, ”Om elcertifikatsystemet,” 23 Juli 2013. [Online]. Available: https://www.energimyndigheten.se/Foretag/Elcertifikat/Om-elcertifikatsystemet/. [Used 16 April 2014].

[22] Svenska Kraftnät, ”CESAR,” [Online]. Available: http://certifikat.svk.se/WebPartPages/AveragePricePage.aspx. [Used 25 April 2014].

[23] Svenska Kraftnät, ”Prislista för stamnätet 2014,” [Online]. Available: http://www.svk.se/PageFiles/57012/stamn%c3%a4tstariff_2013-09-30.pdf. [Used 2 May 2014].

[24] VGB, ”Component Test Facility for a 700 degrees Power Plant,” [Online]. Available: http://www.vgb.org/en/research_project261.html. [Used 26 February 2014].

[25] Naturvårdsverket, ”BRANSCHFAKTA: Förbränningsanläggningar för energiproduktion inklusive rökgaskondensering (utom avfallsförbränning) - Utgåva 2,” Naturvårdsverket, Stockholm, 2005.

[26] U.S. Energy Information Administration, ”Updated Capital Costs Estimates for Utility Scale Electricity Generating Plants,” U.S. Department of Energy, Washington, 2013.

[27] J. Salvatore, G. Turner, H. Boyle, E. Nekhaev, A. Clerici och S. Ulreich, ”World Energy Perspective,” World Energy Council, London, 2013.

[28] V. Tola och A. Pettinau, ”Power generation plants with carbon capture and storage:A techno-economic comparison between coal combustion

and gasification technologies,” *Applied Energy,* vol. 113, pp. 1461-1474, Januari 2014.

[29] M. Heinrich, ”Pöyry report to DECC: Outlook for new coal-fired power stations in Germany, the Nederlands and Spain,” DECC, Oxford, 2013.

[30] Wikipedia, ”Brayton cycle,” [Online]. Available: http://en.wikipedia.org/wiki/Thermodynamic_cycle#mediaviewer/File:Brayton_cycle.svg. [Used 29 August 2014].

[31] M. Genrup och M. Thern, ”Ny gasturbinteknik 2012-2014,” Elforsk, Stockholm, 2013 (Elforsk Rapport 2013:31).

[32] J. Pikkupeura, Personlig kommunikation, *Project Manager Fingrid Oyj.* 23 April 2014.

[33] Fingrid, ”Fingrid's new reserve power plant inaugurated in Forssa,” 25 Mars 2013. [Online]. Available: http://www.fingrid.fi/en/news/announcements/Pages%2FFingrid%E2%80%99s-new-reserve-power-plant-inaugurated-in-Forssa.aspx. [Used 23 April 2014].

[34] Göteborg Energi, ”Rya Kraftvärmeverk - till glädje för alla som bor och verkar i Göteborg,” [Online]. Available: http://www.goteborgenergi.se/Files/dok/Informationsmaterial/Broschyrer/Information%20om%20Rya%20Kraftv%c3%a4rmeverk.pdf?TS=634009609439388750. [Used 14 May 2014].

[35] Swedegas, ”Gaskvalitet i Sverige,” [Online]. Available: http://www.swedegas.se/gas/gaskvalitet/gaskvalitet_i_sverige. [Used 14 May 2014].

[36] Norges vassdrags- og energidoktorat, ”Kostnader ved produksjon av kraft og varme,” Håndbok Nr 1-07, Norges vassdrags- og energidirektorat, Oslo, 2007.

[37] Knottingley Power, ”FAQs,” [Online]. Available: http://www.knottingleypower.co.uk/faqs. [Used 29 August 2014].

[38] General Electric, ”Aeroderivative Gas Turbines For Industrial Cogen Applications,” April 2012. [Online]. Available: http://icci.com.tr/2012sunumlar/O17_Bulent_Mehmetli.pdf. [Used 29 August 2014].

[39] Vattenfall, ”Så fungerar kärnkraft,” [Online]. Available: http://corporate.vattenfall.se/om-energi/el-och-varmeproduktion/karnkraft/sa-fungerar-karnkraft/. [Used 3 July 2014].

[40] K. Ardron och S. Marshall, ”The physics of the EPR and AP1000,” IOP Nuclear Industry Group, 10 November 2010. [Online]. Available: https://www.youtube.com/watch?v=OZXrnw0Slr8. [Used 18 Februaryi 2014].

[41] World Nuclear Association, ”Advanced Nuclear Power Reactors,” May 2014. [Online]. Available: http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Power-Reactors/Advanced-Nuclear-Power-Reactors/. [Used 27 May 2014].

[42] IAEA, ”PRIS - Power Reactor Information System,” [Online]. Available: http://www.iaea.org/PRIS/home.aspx. [Used 21 May 2014].

[43] U.S. Department of Energy, ”Georgia Power Company (GPC), Oglethorpe Power Corp. (OPC), Municipal Electric Authority og Georgia (MEAG),” 19 February 2014. [Online]. Available: http://energy.gov/lpo/georgia-power-company-gpc-oglethorpe-power-corporation-opc-municipal-0. [Used 1 July 2014].

[44] Utility Week, ”Was Hinkley a good deal?,” 17 Januari 2014. [Online]. Available: http://www.utilityweek.co.uk/news/was-hinkley-a-good-deal/967182#.U7KbcrFvlus. [Used 1 July 2014].

[45] IAEA, ”IAEA Issues Projections for Nuclear Power from 2020 to 2050,” 24 September 2013. [Online]. Available: http://www.iaea.org/newscenter/news/2013/np2020.html. [Used 27 May 2014].

[46] OKG, ”Nyheter och pressmeddelanden: OKG förbereder ansökan om miljöprövning för avställnings- och servicedrift på O1,” 27 Januari 2014. [Online]. Available: http://www.okg.se/sv/Press/Nyheter-och-pressmeddelanden/OKG-forbereder-ansokan-om-miljoprovning-for-avstallnings--och-servicedrift-pa-O1/. [Used 2 April 2014].

[47] World Nuclear Association, ”Nuclear Power in Finland,” Mars 2014. [Online]. Available: http://www.world-nuclear.org/info/Country-Profiles/Countries-A-F/Finland/. [Used 14 April 2014].

[48] W. D. D'haeseleer, ”Synthesis on the Economics of Nuclear Energy,” Europeean Commission, DG Energy, Leuven, 2013.

[49] Department of Energy & Climate Change, ”Electricity Generation Costs 2013,” Crown, London, 2013.

[50] International Atomic Energy Agency, ”Climate Change and Nuclear Power 2013,” IAEA, Wien, 2013.

[51] YLE UUTISET, ”TVO unperturbed by nuclear reactor's spiralling cost estimates,” 13 December 2012. [Online]. Available: http://yle.fi/uutiset/tvo_unperturbed_by_nuclear_reactors_spiralling_cost_estimates/6415992. [Used 18 February 2014].

[52] YLE UUTISET, ”Olkiluoto 3 försenad med minst åtta år,” 9 Januari 2014. [Online]. Available: http://svenska.yle.fi/artikel/2014/01/09/olkiluoto-3-forsenad-med-minst-atta-ar. [Used 18 February 2014.

[53] Department of Energy & Climate Change, ”Initial agreement reached on new nuclear power station at Hinkley,” 21 Oktober 2013. [Online]. Available: https://www.gov.uk/government/news/initial-agreement-reached-on-new-nuclear-power-station-at-hinkley. [Used 27 May 2014].

[54] Georgia Power, ”Plant Vogtle units 3 & 4,” [Online]. Available: http://www.southerncompany.com/what-doing/energy-innovation/nuclear-energy/pdfs/Vogtle-Fact-Sheet.pdf. [Used 18 February 2014].

[55] Göteborg Energi, ”Rya Kraftvärmeverk - en anläggning för framtiden,” Göteborg Energi, [Online]. Available: https://www.goteborgenergi.se/Om_oss/Var_verksamhet/Produktionsanlaggningar/Rya_Kraftvarmeverk. [Used 14 April 2014].

[56] E.ON, ”Mer om Öresundsverket,” [Online]. Available: http://www.eon.se/om-eon/Om-energi/Produktion-av-el-gas-varme-

och-kyla/Kraftvarme/Vara-kraftvarmeverk/Oresundverket/Oresundverket/Mer-om-Oresundsverket/. [Used 14 April 2014].

[57] K.-E. Brink, J.-O. Gustafsson, K. Johansson, B. Leckner, H. Miettinen, J. Olofsson, S.-G. Sundqvist och L. Thedén, ”Avancerade ångdata för biobränsleeldade ångprocesser, rapport KME-01,,” Konsortiet för Materialteknik för termiska Energiprocesser, ett samarbetsprojekt mellan Sycon Energikonsult, Stockholm Energi, Kvaerner Pulping, ABB STAL och Chalmers Tekniska Högskola, 1999.

[58] J. Valtatie, Personal communication, *Produktchef, MW Power Oy.* 25 March 2014.

[59] A. Olsson, ”Miljöavgift på utsläpp av kväveoxider från energiproduktion år 2012 - resultat och statistik,” Naturvårdsverket, 2013.

[60] Ö. Jesper Baaring, ”Värme- & kraftföreningen,” 2013. [Online]. Available: http://www.vok.nu/panndagarna-2013/. [Used 4 April 2014].

[61] P. Morén, ”E.ON - The P15-project, Händelö,” 09 maj 2012. [Online]. Available: http://lahtistreams-com-bin.directo.fi/@Bin/506abd678def81946608754b8fca414e/1407827383/application/pdf/169743/13_Moren.pdf. [Used 12 August 2014].

[62] GE Energy, ”Jenbacher type 3,” [Online]. Available: http://www.ge-energy.com/content/multimedia/_files/downloads/ETS_E_T3_12_screen.pdf. [Used 1 May 2014].

[63] S. Merše, B. P. Visocnik, F. Riddoch, S. Craenen, P. Gardiner, T. Rotheray, N. Butterworth, C. Theofylaktos, M. Reijalt och A. Fontana, ”Cogeneration Case Studies Handbook,” Institut Jožef Stefan, Ljubljana, 2011.

[64] Environmental Protection Agency, ”Technology Characterization: Reciprocating Engines,” Environmental Protection Agency, Washington DC, 2008.

[65] M. Lanz och P. Börjesson, ”Förslag till sektorsövergripande biogasstrategi, Bilaga 1 Kostnader och potential för biogas i Sverige,” Energimyndigheten, 2010.

[66] Novergy, ”Products and Technology,” [Online]. Available: http://www.novergy.com.ph/orc.php. [Used 27 June 2014].

[67] B. Kjellström, ”Kostnad för el från småskalig kraftvärme,” Värmeforsk, Stockholm, 2012 (Värmeforsk Rapport 2012:37).

[68] B. Goldschmidt, ”ORC-fallstudier - elproduktion i biobränsleeldat värmeverk eller från spillvärme i massabruk,” Värmeforsk, Stockholm, 2009 (Värmeforsk Rapport 2011:23).

[69] Global Wind Energy Council, ”Global Wind Statistics 2013,” Global Wind Energy Council, Bryssel, 2014.

[70] Global Wind Energy Council, ”Market Forecast for 2014-2018,” Bryssel, 2014.

[71] The European Wind Energy Association, ”Wind in power - 2013 European statistic,” The European Wind Energy Association, 2014.

[72] Energimyndigheten, ”Pressmeddelanden: Minskad utbyggnadstakt för vindkraften,” 18 Juni 2014. [Online]. Available: http://www.energimyndigheten.se/Press/Pressmeddelanden/Minskad-utbyggnadstakt-for-vindkraften/. [Used 23 June 2014].

[73] Svensk Vindenergi, ”Vindkraftsstatistik och prognos, Kvartal 2,” 2014.

[74] Svensk Vindenergi, ”Vindkraftsstatistik Kvartal 1 2014,” 2014.

[75] A. Björck, ”Vindkraft - Teknik- och marknadsutveckling - Delrapport till samorndingsrådet för smarta elnät, preliminär version,” Samordningsrådet för smarta elnät, 2013.

[76] Vindforsk, ”Slutrapport för perioden 2009-2012,” Elforsk, Stockholm, 2013.

[77] European Wind Energy Association, ”The European offshore wind industry - key trends and statistics 2012,” European Wind Energy Association, 2013.

[78] EWEA, ”Upwind - Design limits and solutions for very large wind turbines,” EWEA, Bryssel, 2011.

[79] International Energy Agency, ”Technology Roadmap - Wind Energy, 2013 edition,” IEA, Paris, 2013.

[80] Navigant Research, ”World Market Update 2012,” Navigant Consulting Inc, Boulder, 2013.

[81] S. Jacobsson, F. Dolff och K. Karltorp, ”Bidrag till en handlingsplan för havsbaserad vindkraft i Sverige,” Rapport nr 2013:11, Avdelningen för miljösystemanalys, Instutitionen för energi och miljö, Chalmers Tekniska högskola, Göteborg, 2013.

[82] Energy on numbers, ”Capacity factors at Danish offshore wind farms,” 21 Januari 2014. [Online]. Available: http://energynumbers.info/capacity-factors-at-danish-offshore-wind-farms. [Used 26 February 2014].

[83] LORC, ”Horns Rev 2 Offshore Wind Farm,” [Online]. Available: http://www.lorc.dk/offshore-wind-farms-map/horns-rev-2. [Used 24 June 2014].

[84] Å. Jenssen, F. Krönert, J. Wolst och B. Tennbakk, ”Offshore wind farms as joint projects,” THEMA report 2013-12, Thema Consulting Group, Oslo, 2013.

[85] H. Malmberg, ”Havsbaserad vindkraft i Östersjön - Inventering av frågeställningar och analys av förutsättningar för lönsamhet,” 2012.

[86] The International Renewable Energy Agency, ”Renewable Power Generation Costs in 2012,” IRENA, Bonn, 2012.

[87] B. Stridh och L. Hedström, ”Solceller – Snabbguide och anbudsformulär,” Elforsk, Stockholm, 2011 (Elforsk Rapport 2011:27).

[88] B. Stridh, Personal communication, *Solenergiexpert, ABB.* 7 May 2014.

[89] C. Kost, J. Mayer, J. Thomsen, N. Harmann, C. Senkpiel, S. Philipps, S. Nold, S. Lude, N. Saad och T. Schlegl, ”Levelized cost of electricity renewable energy technologies,” Fraunhoferinstitut For Solar Energy systems I S E, Freiburg, 2013.

[90] B. Stridh, S. Yard, D. Larrson och B. Karlsson, ”Production cost of PV electricity in Sweden,” ABB Corporate Research, Mälardalen University, Lund University, Direct Energy, Västerås, 2013.

[91] B. Ricardo, Personlig kommunikation, *Forskare vid Energi och ByggnadsDesign.* 11 januari 2014.

[92] Elforsk, ”SolElprogrammet - Energiberäkningar,” [Online]. Available: http://www.solelprogrammet.se/projekteringsverktyg/energiberakningar/. [Used 16 May 2014].

[93] Euronom AB, ”Världsmästare på solpaneler,” [Online]. Available: http://www.euronom.se/269_SUN_POWER__Solpaneler. [Used 28 March 2014].

[94] NREL National Center for Photovoltaics, ”Best Research-Cell Efficiencies,” 07 mars 2014. [Online]. Available: http://www.nrel.gov/ncpv/images/efficiency_chart.jpg. [Used 7 March 2014].

[95] Y. D. Goswam, F. Kreith och J. F. Kreider, Principles of Solar Engineering, New York: Taylor & Francis Group, 2000.

[96] J. Lindahl, ”National Survey Report of PV Power Applications in Sweden 2013,” International Energy Agency, Uppsala, 2014.

[97] A. Jäger-Waldau, ”PV Status Report 2013,” European Commission, DG Joint Research Centre, Institute for Energy and Transport, Renewable Energy Unit, Italiy, 2013.

[98] B. Burger, ”Fraunhofer Institute for Solar Energy Systems ISE,” 9 januari 2014. [Online]. Available: http://www.ise.fraunhofer.de/en/downloads-englisch/pdf-files-englisch/news/electricity-production-from-solar-and-wind-in-germany-in-2013.pdf. [Used 7 March 2014].

[99] P. Mints, ”April Fools, Magical Thinking, and PV Manufacturer Shipment Announcements,” Renewable Energy World.com, 2014.

[100] J. Paradis, ”Lönsam solel? Faktorer för en lyckad implementering av solceller,” Västra Götalandsregionen, 2012.

[101] Solibro, ”Cigs Solar Module SL2,” 2014. [Online]. Available: http://www.directenergy.se/dokument/datablad/Datasheet_SL2_G1.4_EN_2012_09_27.pdf. [Used 28 March 2014].

[102] Uppsalahem, ”Frodeparken,” 2013. [Online]. Available: https://www.uppsalahem.se/PageFiles/5089/fakta-frode.pdf. [Used 30 April 2014].

[103] Absolicon, ”Värme och el till närvärmenät,” 07 mars 2014. [Online]. Available: http://www.absolicon.se/case/baverglantan-smedjebacken/. [Used 4 March 2014].

[104] Absolicon, ”Härnösands Energipark,” [Online]. Available: http://www.absolicon.se/wp-content/uploads/2012/05/energi_park_absolicon.pdf. [Used 13 March 2014].

[105] J. Paradis, personal communication, *Drift och underhåll av solcellsanläggningar, Energibanken.* 20 March 2014.

[106] D. H. K. Sven-Ingvar Petersson, personal communication, *Drift och underhåll för solcellsanläggningar.* 6 March 2014.

[107] K. Bengtsson, Personlig kommunikation, *Drift och underhåll solcellsanläggningar, Euronom.* 25 March 2014.

[108] Energimyndigheten, ”Stöd till solceller,” 29 januari 2014. [Online]. Available: https://www.energimyndigheten.se/Hushall/Aktuella-bidrag-och-stod-du-kan-soka/Stod-till-solceller/. [Use 7 March 2014].

[109] A. Borg och N. Ekstrand, ”Skattereduktion för mikroproduktion av förnybar el,” Finansdepartementet, Stockholm, 2014.

[110] Opcon Energy Systems, ”Opcons ORC-system i Opcon Powerbox,” [Online]. Available: http://www.opcon.se/web/Opcons_ORC-system_1_1.aspx. [Used 1 September 2014].

[111] E.ON, ”Hur ser ett värmeföretag på småskalig kraftvärme,” 21 Februari 2013. [Online]. Available: https://www.yumpu.com/sv/document/view/24081091/7-eon-hur-ser-ett-varmefaretag-pa-smaskalig-kraftvarmepdf. [Used 26 June 2014].

[112] L. Waldheim och E. K. Larsson, ”Inventering av framtidens el-och värmeproduktionstekniker, Delrapport Förgasning med gasturbin/motor för kraftvärme,” Elforsk, Stockholm, 2008 (Elforsk Rapport 2008:78).

[113] C. Breitholtz, ”The biomass gasification plant to Vaskiluodon Voima in Vaasa and two more ongoing gasification projects,” i *SolanderSymposium*, 2011.

[114] RICARDO-AEA, ”Case Study 1 - Lahti Gasification Facility, Finland,” Zero Waste South Australia, 2013.

[115] C. Breitholtz, Personlig kommunikation, *Utvecklingsingenjör, Valmet.* 19 februari 2014.

[116] Energinet.dk, ”Technology data for energy plants,” Energistyrelsen, Danmark, 2012.

[117] React Energy, ”Newry Biomass Limited,” 2014. [Online]. Available: http://www.reactenergyplc.com/projects/32-newry-biomass-4mw-chp-northern-ireland. [Used 6 May 2014].

[118] Zeropoint Cleantech, ”Zeropoint Cleantech News,” 6 augusti 2012. [Online]. Available: http://www.zeropointcleantech.com/news. [Used 6 May 2014]].

[119] T. Henderson, ”Proposal for planning permit, Energyforlondon.org,” 27 juli 2010. [Online]. Available: http://www.energyforlondon.org/wp-content/uploads/2013/03/Kedco-Biomass-Planning-Report.pdf. [Used 6 May 2014]].

[120] Babcock & Wilcox Völund, ”Gasification of wood chips,” [Online]. Available: http://www.volund.dk/en/Biomass_energy/Technologies/~/media/Downloads/Brochures%20-%20BIO/Biomass%20gasification%20plants.ashx. [Used 6 May 2014]].

[121] J. Rusanova, ”Technological Alternatives or Use of Wood Fuel in Combined Heat and Power Production,” *Environmental and Climate Technologies,* vol. 12, pp. 10-14, 2013.

[122] IVL Svenska Miljöinstitutet, ”Förutsättningar för avskiljning och lagring av koldioxid (CCS) i Sverige,” Rapport B1969, IVL Svenska Miljöinstitutet, Stockholm, 2011.

[123] Global CCS Institute, ”The Global Status of CCS - February 2014,” Global CCS Institute, 2014.

[124] SaskPower, ”Boundary Dam Integrated Carbon Capture and Storage Demonstration Project,” April 2012. [Online]. Available: http://www.saskpower.com/wp-content/uploads/clean_coal_information_sheet.pdf. [Used 20 March 2014].

[125] SaskPower, ”Update on SaskPower's Carbon Capture Test Facility,” 13 Juni 2014. [Online]. Available: https://www.youtube.com/watch?v=B8Wp88qQQSI&feature=youtu.be. [Used 1 July 2014].

[126] Zero Emissions Platform, ”The Costs of CO2 Capture, Transport and Storage,” European Technology Platform for Zero Emission Fossil Fuel Power Plants, 2011.

[127] E. Wetterlund, K. Pettersson och S. Harvey, ”INTEGRATING BIOMASS GASIFICATION WITH PULP AND PAPER PRODUCTION – SYSTEMS ANALYSIS OF ECONOMIC PERFORMANCE AND CO2 EMISSIONS,” i *22nd International Conference on Efficiency, Cost, Optimization Simulation and Environmental Impact of Energy Systems*, Foz do Iguaçu, 2009.

[128] P. Holmberg, M. Andersson, B. Bolund och K. Strandanger, ”Wave Power,” Elforsk, Stockholm, 2011 (Elforsk Rapport 2011:02).

[129] Framtidens Energi, ”Premiär för Sveriges första stora vågkraftspark,” 31 Januari 2014. [Online]. Available: http://framtidensenergi.net/foretagspresentation/premiar-for-sveriges-forsta-stora-vagkraftspark/. [Used 3 February 2014].

[130] Seabased, ”Bildarkiv,” [Online]. Available: http://seabased.com/sv/nyhetsrum/bildarkiv. [Used 1 September 2014].

[131] IPCC, ”Renewable Energy Sources and Climate Change Mitigation,” Cambridge University Press, New York, 2012.

[132] Seabased AB, ”Vågkraft i Sotenäs,” [Online]. Available: http://www.seabased.com/sv/projekt/sotenaes. [Used 18 February 2014].

[133] Energinyheter.se, ”Första vågkraftsverken nu i havet,” 3 Juli 2014. [Online]. Available: http://www.energinyheter.se/2014/07/f-rsta-v-gkraftverken-nu-i-havet. [Used 4 July 2014].

[134] Energinyheter.se, ”Världens största vågkraftspark påbörjad,” 2 Juli 2014. [Online]. Available: http://www.energinyheter.se/2014/07/v-rldens-st-rsta-v-gkraftspark-p-b-rjad. [Used 4 July 2014].

[135] Pelamis Wave Power, ”About Pelamis Wave Power,” [Online]. Available: http://www.pelamiswave.com/about-us. [Used 18 February 2014].

[136] Ernst & Young, ”Cost of and financial support for wave, tidal stream and tidal range generation in the UK,” DECC, 2010.

[137] Johansson, Billy, ”Webbsänt möte om den maritima strategin,” 19 Februari 2014. [Online]. Available: http://www.regeringen.se/pub/road/Classic/article/19/jsp/Render.jsp?a=234259&x=xml&filmId=0&popup=true&seek=22. [Used 24 March 2014].

[138] Strategic Initiative for Ocean Energy, ”Ocean Energy: Cost of Energy and Cost Reduction Opportunities,” 2013.

[139] Carbon Trust, ”Why it's time to get serious about wave power,” 22 Oktober 2012. [Online]. Available: http://www.carbontrust.com/news/2012/10/why-its-time-to-get-serious-about-wave-power. [Used 18 February 2014].

[140] Skatteverket, ”Skatteverkets allmänna råd om riktvärdeangivelser och grunderna för taxeringen och värdesättningen av elproduktionsenheter vid 2013 års allmänna fastighetstaxering,” 31 Augusti 2012. [Online]. Available: http://www.skatteverket.se/rattsinformation/reglerochstallningstaganden/allmannarad/2012/allmannarad2012/skva201209.5.71004e4c133e23bf6db8000104742.html. [Used 25 February 2014].

ELFORSK

SVENSKA ELFÖRETAGENS FORSKNINGS- OCH UTVECKLINGS - ELFORSK - AB

Elforsk AB, 101 53 Stockholm. Besöksadress: Olof Palmes Gata 31
Telefon: 08-677 25 30, Telefax: 08-677 25 35
www.elforsk.se