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REPLACING COAL WITH BIOMASS FUELS IN COMBINED HEAT AND POWER PLANTS IN FINLAND

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ABSTRACT: To meet the renewable energy targets by 2020 in Finland, the use of coal to produce electricity and heat could be partially replaced with renewable biomass fuels. VTT has made a background report for Ministry of Employment and the Economy in which the purpose was to analyse possibilities to replace coal with biomass in combined heat and power plants using pulverised fuel combustion method and to analyse the economic instruments for supporting the use of biomass fuels. In this study it has been estimated that about 4 TWh coal could be replaced annually with biomass fuels until 2015 at the studied plants. In short term more than 0.5 TWh coal could be replaced with wood pellets and later 0.6 TWh with other upgraded biomass fuels such as torrefied biomass by introducing feed-in subsidies. Use of forest chips could be increased by about 2 TWh by adopting investment subsidies for biomass gasifiers utilising new technology. Use of agrobiomass fuels could be increased about 0.5 TWh mainly as a feedstock for gasifiers. It is also estimated that via alternative biomass utilisation options (e.g. new separate multifuel boilers) and other CO_2 reducing means (e.g. new waste-to-energy plants) of the studied energy companies additional 3 TWh coal could be replaced annually within few years. Totally about 10 M€ will be needed for feed-in subsidies when upgraded biomass fuels and agrobiomass will be utilised and about 80 M€ will be needed for investment subsidies until 2015 including investment subsidies to upgraded biomass production. One great challenge is to secure adequate biomass supply for coal fired power plants without reducing biomass use in existing power plants. Also some technical options need more development before commercial utilisation.

Keywords: biomass, co-firing, subsidy

1 INTRODUCTION

Co-firing is defined as simultaneous combustion of different fuels in the same boiler. When biomass is used in co-firing, it represents one interesting alternative for reducing greenhouse gas emissions. Basically one can distinguish three different concepts for co-firing biomass with coal, all of which have already been implemented either on a demonstration or a fully commercial basis, and each with its own particular merits and disadvantages. Direct co-firing is the most straightforward applied, most commonly applied and low-cost of all. Biomass fuel and coal are combusted together in the same furnace, using the same or separate mills and burners depending on the biomass fuel characteristics. In the concept of indirect co-firing, a biomass gasifier can be used to convert solid biomass raw materials into a clean fuel gas form, which can be combusted in the same furnace as coal. This offers the advantages that a wider range of biomass fuels can be used (e.g. difficult to grind) and that the fuel gas can eventually be cleaned and filtered to remove impurities before it is combusted. Finally it is also possible to install a completely separate biomass boiler and increase the steam parameters in the coal power plant steam system. [1]

Globally there has been rapid progress over the past 10 years in the development of the co-utilisation of biomass materials in coal-fired boiler plants. Several plants have been retrofitted for co-firing purposes, while another number of new plants are already being designed for involving biomass co-utilisation with fossil fuels. Tests have been performed with every commercially significant (lignite, subbituminous coal, bituminous coal) fuel type, and with every major category of biomass (herbaceous and woody fuel types generated as residues and energy crops). [1] On European level biomass has been used mainly in fluidised bed and grate boilers, especially in Sweden and Finland. However, biomass is quite rarely combusted with coal or other fossil fuels in those boilers. In Finland the most common biomass used in large scale is wood based, such as bark, saw dust and forest residue. Utilisation of demolition wood has also increased during last years. The other available and used biomass in EU is different agricultural residues (straw, vineyards, olive oil pressing, almond shells and peels etc.) and energy crops, but in Finland the use of agricultural residues is very minimal.

To meet the renewable energy targets by 2020 in Finland it is intended that the use of coal to produce electricity and heat (currently around 14 TWh/a) should be partially (7 – 8 TWh/a) replaced with renewable biomass fuels. The work to determine the variable production subsidy and investment subsidies needed to fulfil the target is in progress. VTT has made a background report for Ministry of Employment and the Economy for which VTT analysed all Finnish coal fired combined heat and power plants (7 units) to find out overall possibilities to replace coal with biomass fuels. Owners of coal fired power plants and main biomass fuel procurement companies were interviewed to collect basic data from power plants, possible investment plans, experiences of biomass use and estimates of biomass supply etc. The coal fired condensing power plants were not included in the study. The use of coal in these plants has been around 15 – 40 TWh/a and there lays also major possibilities for emission reduction, but in the context of overall renewable energy the share is less than in CHP-plants.

This paper contains a short description of biomass co-firing technologies that could be used in Finnish coal-fired CHP-plants. The following pages give some indications of the needed equipment, plant operation effects and costs of operation. Also the economic instruments for supporting the use of biomass fuels in Finland will be presented.

2 TECHNOLOGY OPTIONS FOR CO-FIRING IN COAL-FIRED PLANTS

2.1 General

Co-firing biomass with coal in traditional coal-fired boilers represents one combination of renewable and fossil energy utilisation that derives the greatest benefit from both fuel types. It capitalises on the large investment and infrastructure associated with the existing fossil-fuel-based power systems, while requiring only a relatively modest investment to include a fraction of biomass in the fuel. [1]

Increased need for reduction of CO_2 emissions in energy production has resulted in development of different co-firing technologies and demonstration of them in industrial scale. Large number of new and advanced co-firing technologies have been adopted successfully to commercial operation and several new technologies are still in development and demonstration phase.

Co-firing is typically favoured in large scale when supply of large volumes of biomass is difficult to arrange. In practice, it is usual that biomass fuel is not a single fraction but it is a mixture of several bioresidues or fuels. The properties of coal and biomass fuels differ significantly. The typical differences between coal and biomass fuels are moisture content, bulk density, volatiles and often ash (amount and composition). In addition, due to lower calorific value and high moisture content, the energy content (energy density) is typically significantly lower. [2]

Depending on the co-firing technology to be used these properties have different effect on the maximum output and share of biomass fuels. Basically there are three different concepts for co-firing biomass with coal:

- Direct co-firing, where biomass fuel and coal are combusted together in the same furnace.
- Indirect co-firing, where the solid biomass is converted via gasification or pyrolysis into a fuel gas or liquid which is subsequently combusted together with coal in the same furnace.
- Indirect co-firing, with separate biomass boiler and coal fired boiler and integrating steam cycles.

2.2 Direct co-firing

In direct co-firing in PC (pulverised coal) boilers there are basically four options for introducing the biomass. In the **first** option, the pre-processed biomass is mixed with coal upstream of the existing coal feeders. The fuel mixture is fed into the existing coal mills that pulverise coal and biomass together, and distribute it across the existing coal burners, based on the required co-firing rate. This is the simplest option, involving the lowest capital costs, but has a highest risk of interference with the coal firing capability of the boiler unit. Due to the biomass ash properties harmful deposits can build-up on heating surfaces of the boiler reducing output and operational time. Furthermore, different combustion characteristics of coal and biomass may affect the stability and heat transfer characteristics of the flame. Thus, this direct co-firing option is applicable to a limited range of biomass types and at very low biomass-to-coal co-firing ratios.

The **second** option involves separate handling and pulverisation of the biomass, but injection of the pulverised biomass into the existing pulverised fuel pipe-work upstream of the burners or at the burners. This option requires only modifications external to the boiler. One disadvantage would be the requirement of additional equipment around the boiler, which may already be congested. It may also be difficult to control and to maintain the burner operating characteristics over the normal boiler load curve.

The **third** option involves the separate handling and pulverisation of the biomass fuel with combustion through a number of burners located in the lower furnace, dedicated to the burning of the biomass alone. This demands a highest capital cost, but involves the least risk to normal boiler operation as the burners are specifically designed for biomass burning and would not interfere with the coal burners.

The **fourth** option involves the use of biomass as a reburn fuel for NO_x emission control. This option involves separate biomass handling and pulverisation, with installation of separate biomass-fired burners at the exit of the furnace. As with the previous option, the capital cost is high, but risk to boiler operation is minimal. [3, 4, 5, 6]

Biopellets (or wood pellets) offer many attractive properties in comparison to untreated biomass. With respect to heating value, grindability, combustion nature, storage, transport and handling, biopellets are in many cases the superior fuel. Large-particle biomass feedstocks are difficult to grind in the existing coal mills due to their tenacious and fibrous nature, but biopellets are already composed of small particles and in a coal mill they are readily disintegrated (crushed) to these original particles. Biomass derived fuel pellets are, however, rather expensive, require storage facilities, and still need modifications in the processing infrastructure of the power plant. Moreover, availability of biomass fuel pellets is limited, as they cannot be produced from a wide variety of biomass feedstock. Thus, new techniques are searched to increase the co-firing rates to higher levels.

Torrefaction is a pre-treatment technology to make biomass more suitable for co-firing applications. Torrefaction refers to thermochemical treatment of biomass at 200 to 300 °C. It is carried out under atmospheric conditions and in the absence of oxygen. In addition, the process is characterised by low particle heating rates (< 50 °C/min). During the process the biomass partly decomposes giving off various types of volatiles. The final product is the remaining solid, which is often referred to as torrefied biomass, or torrefied wood when produced from woody biomass. Biomass is completely dried during torrefaction and after torrefaction the uptake of moisture is very limited. This varies from 1-6% depending on the torrefaction conditions and the treatment of the product afterwards. The improved grindability of biomass after torrefaction may enable higher co-firing rates in the near future. Torrefaction is, however, a technology that is not commercially available yet. Currently only minor co-firing experience exists at industrial scale, thereby it is difficult to evaluate real impacts associated with the operation of boiler equipment. [7]

If not carefully designed, firing biomass fuels in an existing coal fired power plant involves risks of increased plant outages, possible interference with the operation of the burners, the furnace, the boiler convective section, and the environmental control equipment. Results to date indicate that these are all manageable but that they require careful consideration of fuels, boiler operating conditions, and boiler design.

2.3 Indirect co-firing technologies

Indirect co-firing means process concept, which is based on thermal conversion of biomass or waste to gaseous or liquid fuel and co-firing of these converted fuels together with the main fuel. Indirect co-firing has several technical and economic benefits compared to direct co-firing, especially in the case of pulverised coal fired boiler. Until now all industrial scale and commercially operated indirect co-firing applications are based on gasification of biomass and co-firing of product gas in larger scale PC boiler.

However, fast pyrolysis technology and production of pyrolysis oil from biomass is under development and commercialisation and this can offer another route to implement indirect co-firing.

Gasification is a thermal conversion process, which converts solid (or in some specific cases liquid) fuel to combustible gaseous fuel. Typical gasification process is based on partial combustion of the fuel in order to produce heat required to maintain temperature favourable for gasification reactions. Product of gasification processes is gas containing CO, CO_2, H_2, C_xH_y, H_2O and some impurities and in addition nitrogen when air-blown gasification is applied.

Fast pyrolysis is a technology, which thermally converts solid biomass to liquid form. Technically fast pyrolysis process is relatively similar than gasification process but reaction atmosphere does not contain oxygen. Gasification process needs some oxygen but after gasification reactions the product gas is oxygen free. Conversion efficiency from solid biomass to liquid product varies depending on biomass, pyrolysis process, etc. and is typically 40...65 %. The fuel properties of pyrolysis oil are comparable to heavy fuel oil but chemical composition is different. Pyrolysis oil contains significant amount of water, which can be reduced by hot condensation technology. Lower heating value is about 13-18 MJ/kg, which is significantly lower than in mineral oils.

Co-firing of biomass with fossil fuels can also be organised by having a separate biomass boiler and fossil fuel fired boiler and integrating steam cycles. For example steam can be generated in a biomass fired boiler and superheated in a coal fired boiler. This type of integration enables very safe way to avoid risks related to deposit formation and corrosion caused by high steam parameters in a biomass fired boiler. [8]

3 EVALUATION OF CO-FIRING COSTS IN FINNISH COAL-FIRED PLANTS

3.1 Studied biomass types and technologies for co-firing

It is possible to replace coal with biomass (typically max. 5 % of the total fuel energy input) by adding **sawdust** (or similar particle size biomass) through existing coal fuel handling and feeding lines without any major investments or increase in the operation costs. By using **pellets** some 15 % share can be utilised with only minor investments in fuel feeding systems (e.g. pellet storage, connection conveyors to coal lines). The biomass in pellets in Finland is typically sawdust or cutter chips, but also other industrial by-product can be used as well as some share of agrobiomass.

With separate **biomass line** (designed especially for specific feedstock) it is possible to utilise dry, fine particle size biomass up to 30 % share of the total fuel input. The biomass line includes fuel reception, chipping/fining, drying and separate feeding lines into specific biomass burners in the boiler. The investment, including the drying stage, is about 10-15 M€ for 70-100 MW capacity. There are significant space requirements at the site, which can limit this technical option the in practise.

As much as 50 % of the total coal consumption could be replaced if the biomass is **gasified** or it is upgraded to **torrefied** biomass or bio-oil. The investment in gasification plant is around 30-40 M€ for 120-150 MW capacity, so the remaining lifetime of the main boiler should be still significant in order to make the investment reasonable. The space requirements at the site are vast. The use of torrefied biomass and bio-oil does not require major investments for the boiler, but the biomass storage is needed within the site (or elsewhere) as well as conveyors to coal feeding systems.

It is possible to transport biomass in gaseous form (methane) by using natural gas network. This biomass based synthetic natural gas can be utilised most cost-efficiently in natural gas fired power plants which can also reduce the operation of coal-fired plants.

3.2 Co-firing possibilities and limitations in practice

In the studied CHP plants the annual use of coal has been about 14 TWh. Possibilities and costs of co-firing investments when replacing coal vary a lot. Also the availability and price of biomass fuels vary much in different municipalities. Roughly it can be estimated that about 500 GWh biomass is available within 150 km radius of the studied plants excluding Helsinki-Espoo-Vantaa area. There is vast biomass potential e.g. in eastern Finland from where biomass could be delivered with rail. 500 km rail or water transport would increase the costs of upgraded biomass about 5 €/MWh. There are many alternative (competitive) routes for biomass utilisation (e.g. multi-fuel boilers, use outside of the ETS-sector, liquid biofuels etc.) which needs to be taken into account when evaluating realistic potential for the co-fired coal plants.

The boiler design has to be taken into account when evaluating the maximum share of biomass to be used in order to avoid significant decrease in boiler operational values (output, efficiency, electricity-to-heat-ratio). The available space and boiler location at the plant site have an effect on the technical options for fuel storage, handling and feeding. Also the biomass transport options (water, rail, road) are dependent on the location of the specific plant.

The use of biomass increases operational costs of the plant through negative effects on the availability of the boiler and increased maintenance work and consumables. Factors, such as, ash deposition, increased corrosion rates of high temperature boiler components, higher in-house power consumption and fly ash utilisation can bring typically some 1-5 % increase on the overall costs of operation.

The feasibility of the investment (and the willingness to invest) is affected by the remaining lifetime of the plant and the annual operating hours. By 2016 SOx, NOx and particulate emission limits will be tightened according to Directive on Industrial Emissions (IE-directive) which means significant investments at several plants. This affects also on the co-firing possibilities at the current plants, e.g. via alternative biomass utilisation options (new multifuel boilers) of the energy companies. Also the merit order of natural gas fired plants over coal fired ones at Helsinki, Espoo and Vantaa and other CO_2 reducing means of the energy companies (e.g. waste-to-energy plants) are significant variables in the matrix.

3.3 Feasibility evaluation for a nominal plant

In order to evaluate the feasibility of different co-firing options in Finnish conditions operation cost calculations were conducted for a nominal plant which represents typical coal-fired CHP-plant in Finland. The plant produces 230 MW district heat and 115 MW electricity. Corresponding fuel input is 400 MW and the annual total fuel consumption 2 TWh (with 5000 h/a). Besides coal, some heavy fuel oil is used in the boiler for start-ups.

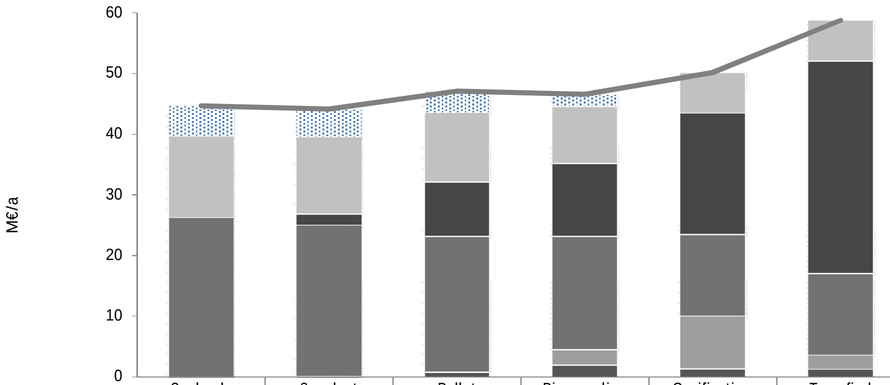
The calculations were conducted with coal and emission allowance prices of early 2011 (coal 13 €/MWh, CO_2 15 €/t) and with IEA World Energy Outlook's New policy scenario for 2020 (coal 10 €/MWh, CO_2 30 €/t). In both cases the taxation for coal was in 2011 level (12.98 €/MWh_{heat}) and share of free emission allowances 50 %. [9]

Major investments are needed in gasification, biomass line and torrefied biomass co-firing options. The investments used in the study are estimates of typical average costs, but there are great variations from plant-to-plant depending on the site specific conditions. The capital costs are calculated with 8 % interest rate and 12 year economic life.

Biomass shares in studied co-firing cases were: sawdust 5 %, pellets 15 %, biomass line 30 %, gasified biomass 50 % and torrefied biomass 50 %. In the gasification case the syn gas in this study is produced from forest residues and the feedstock for biomass line is also forest residue based.

The biomass prices (delivered to the site) in both scenarios were: sawdust 18 €/MWh, forest residues 20 €/MWh, pellets 30 €/MWh and torrefied biomass 35 €/MWh. The difference in costs of logistics and the availability of different fuels are also very site-specific in practice. The variation in biomass prices can be up to 5–10 €/MWh. There lays many uncertainties with the price of torrefied biomass and bio-oil since the first production plants are still under construction or development in Europe.

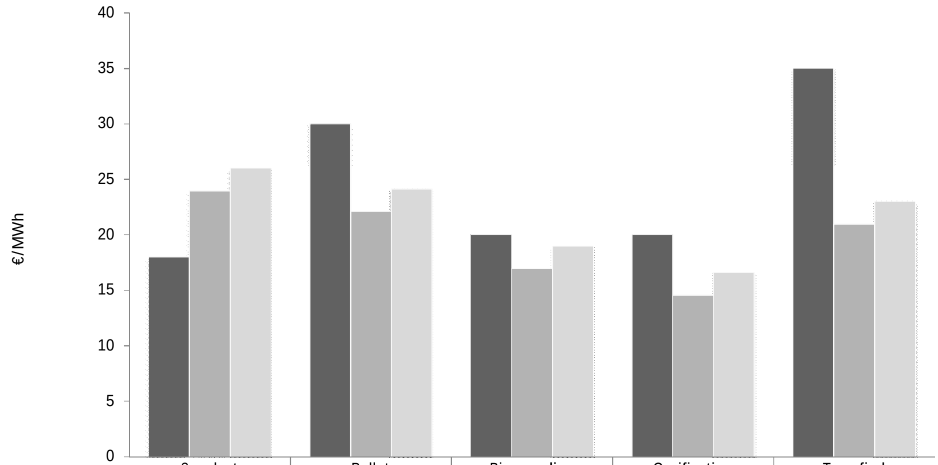
The costs of nominal plant operation in different co-firing options with early 2011 (coal 13 €/MWh, CO_2 15 €/t) prices are presented in figure 1 in comparison with the normal operation (coal only). The greatest increase on costs originates form biomass purchase and also the capital costs in gasifier-case are significant. With IEA 2020 prices (coal 10 €/MWh, CO_2 30 €/t) the overall situation is not significantly changed, however, the competitiveness of biomass in increased in every case. The presented variable operating costs due to biomass take into account biomass handling and feeding, loss in the availability of the boiler, plants in-house electricity consumption, fly-ash utilisation etc.



	Coal only	Sawdust	Pellet	Biomass line	Gasification	Torrefied
CO2-allowances	5.1	4.5	3.5	2.0	0.0	0.0
Taxation for fossil heat	13.4	12.8	11.4	9.4	6.7	6.7
Biomass purchase	0	1.8	9.0	12.0	20.0	35.0
Coal purchase	26.2	24.9	22.3	18.7	13.5	13.5
BIO: capital costs	0	0.0	0.1	2.5	8.7	2.4
BIO: variable extra costs	0	0.1	0.7	2.0	1.3	1.2
Total (M€/a)	44.7	44.1	47.1	46.5	50.1	58.7

Figure 1. Annual operating costs of the studied nominal plant (M€/a) in the reference-case (coal only) and in different co-firing cases. Biomass share in co-firing cases: sawdust 5 %, pellets 15 %, biomass line 30 %, gasified biomass 50 % and torrefied biomass 50 %. Coal price was 13 €/MWh and CO_2-emission allowance 15 €/t (early 2011-scenario).

The results of the feasibility analysis can be presented also as break-point prices for different biomass fuels, see figure 2. This is defined as price that leads to equal annual operating costs compared to pure coal-fired case. With early 2011 price-scenario the plant could pay 24 €/MWh for sawdust (coal replacement share 5 %), 22 €/MWh for pellets (15 % share), 17 €/MWh for biomass fed through separate feeding line (max 30 % share), 15 €/MWh for gasified biomass (max 50 % share) and 21 €/MWh for torrefied biomass (max 50 % share). With the IEA 2020 price-scenario the break-point biomass price is some 2 €/MWh higher on average. The results show that the plant's ability to pay is lower than current prices of biomass, with the exception of sawdust (in 5 % share) so in general subsidy instruments are needed to promote the use of biomass in coal-fired CHP-plants.



	Sawdust	Pellet	Biomass line	Gasification	Torrefied
Default price	18	30	20	20	35
Early 2011	24.0	22.1	16.9	14.6	21.0
Energy Outlook 2020	26.0	24.2	19.0	16.6	23.0

Figure 2. Break-point prices (€/MWh) of different biomass fuels, defined as price where the annual operating costs compared to pure coal-fired case are equal. Default price: the price of biomass used in the study. Early 2011: plant's ability to pay when coal price is 13 €/MWh and CO_2 is 15 €/t. Energy Outlook 2020: plant's ability to pay when coal price is 10 €/MWh and CO_2 is 30 €/t.

4. SUBSIDY EVALUATION

In this study two alternative subsidy elements have been considered - feed-in subsidy for biomass based electricity from CHP-production and investment subsidy for new biomass technology.

To support the use of forest residues new subsidy has been taken into action in Finland during spring 2011 (based on law 1396/2010). The subsidy is for forest residues based electricity and it is dependent on the price of emission allowances so that the level is 18€/MWh with 10 €/t CO_2-price and decreases linearly to zero level with 23 €/t CO_2-price. With this current subsidy the studied coal-biomass co-firing cases manage poorly. With early 2011-price scenario for coal and CO_2 it only enables the use of forest residues in the case of biomass line, see figure 3. Higher subsidy is needed to make gasification and the use of pellets and torrefied biomass feasible. With IEA 2020 -price scenario for coal and CO_2 all co-firing cases are unfeasible. It is estimated that if agrobiomass would also get the current subsidy it would become important fuel especially for coal-fired plants.

If the variable feed-in subsidy for forest residues would be increased for coal-fired CHP-plants only it would place other Finnish forest residue utilising plants in unequal position. Because the studied coal-fired CHP-plants are located near other plants willing to use forest residues higher subsidy for coal plants would direct biomass away from these other plants. Thus, the higher subsidy for coal plants is difficult to justify.

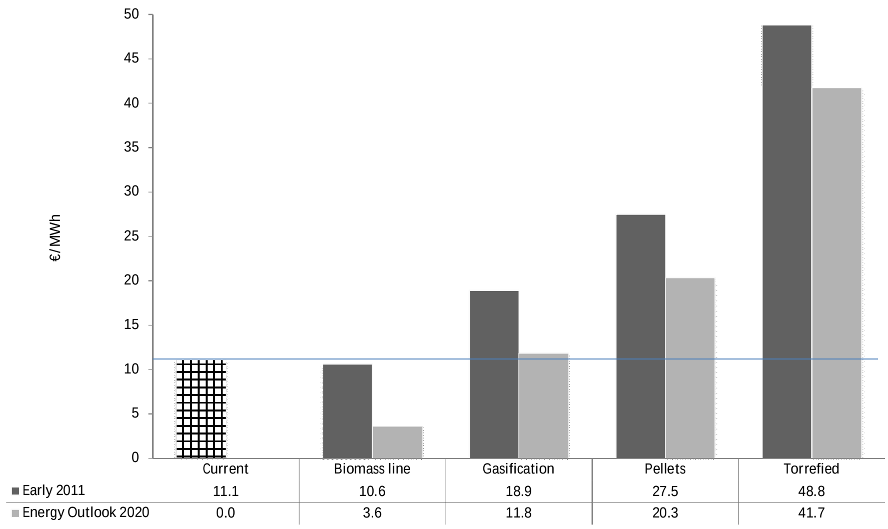


Figure 3. The current variable feed-in subsidy for forest residue based electricity compared to the needed biomass feed-in subsidy in different co-firing options with early 2011- and IEA 2020 -price scenarios for coal and CO_2. Biomass share in different co-firing cases: biomass line 30 %, gasified biomass 50 %, pellets 15 % and torrefied biomass 50 %.

The competitiveness of biomass can be increased also via investment subsidies. In this case only biomass line and gasification co-firing options are presented because of their high investment need, see figure 4. Also torrefied biomass requires investments at the plant, but due to the lack of its commercial operation experience it was neglected in this approach. With studied input parameters the needed investment subsidy for gasification plant is in the range of 40 % of the total investment. For the biomass line no subsidy is needed with early 2011 price scenario, but with IEA 2020 scenario the level of investment subsidy would be over 30 %.

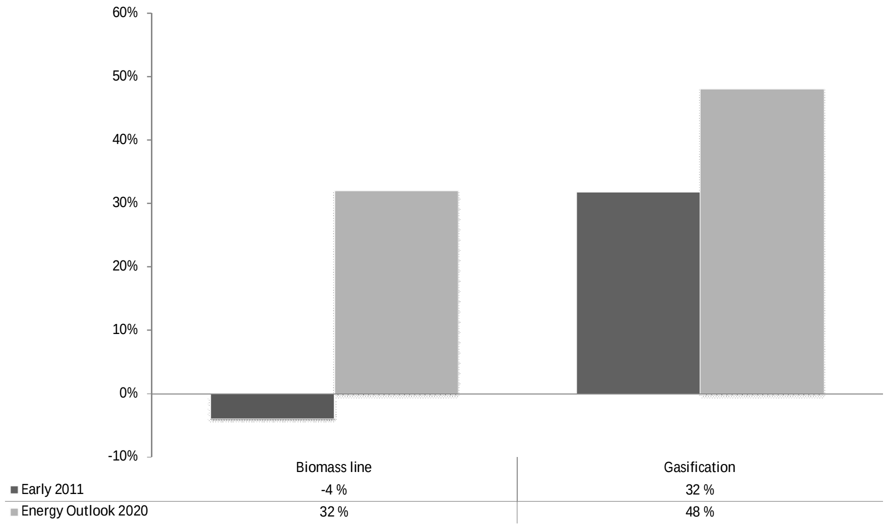


Figure 4. The needed investment subsidy of the total investment for biomass line and gasification co-firing options with early 2011- and IEA 2020 -price scenarios for coal and CO_2.

The site-specific more detailed studies revealed the fact that the technical possibilities to replace coal and costs of co-firing vary a lot. When high investment is required high annual utilisation level and high output are beneficial. The lowest variations in the subsidy need are with plants that use upgraded biomass where the main extra costs are fuel-derived.

5 CONCLUSIONS

According to this study there is not enough biomass available at such prices that would enable significant coal replacements in coal-fired CHP-plants. If the variable feed-in subsidy for forest residues would be increased for coal-fired CHP-plants only it would place other Finnish forest residue utilising plants in unequal position. Thus, the higher subsidy for coal plants is difficult to justify.

Investment subsidies for biomass lines and gasification would commit the plants to use high shares (up to 50 %) of versatile biomass resources. If agrobiomass would also get the current feed-in subsidy it would become important fuel especially for coal-fired plants.

In plants where there’s not enough space available for biomass systems the use of upgraded biomass products is still possible. The production of upgraded biomass products could be carried out at locations where biomass is available. It is suggested that some sort of investment subsidy at least for the first production plants of torrefied biomass, bio-oil, and synthetic biogas should be granted to make the start at the markets feasible.

New feed-in subsidy for upgraded biomass products could be at higher level than current subsidy for forest residues in order to encourage the use. Annual minimum level of biomass use (e.g. more than 150 GWh) should be included as requisite to make coal replacement level more significant and to create more predictable market volume to the fuel producers. The prices of emission allowances and coal are crucial and they need to be taken into account when defining the level of feed-in subsidy for upgraded biomass products.

In the following table (table 1) the summary of possibilities for coal replacement at studied CHP-plants are presented together with the needed subsidies. These are evaluated until 2015 with early 2011 prices for coal and CO_2. By means of the proposed actions the use of coal could be reduced by 2,8–4,1 TWh annually within few years which could reduce the CO_2 emissions in the ETS-sector by 1,4 Mtn/a at maximum. It is also estimated that via alternative biomass utilisation options (new separate multifuel boilers) and other CO_2 reducing means (e.g. waste-to-energy plants) of the energy companies additional 3 TWh coal could be replaced annually within few years.

Table 1. The summary of possibilities for coal replacement at studied CHP-plants with needed investment and feed-in subsidies.

Action	Coal replacement possibility within few years TWh/a	Needed subsidy with early 2011 coal & CO_2 prices	Total sudsidy (M€/a, M€)
Use of sawdust, low-cost fuel batches	0.2	-	-
Promotion of pellet use: feed-in tariff based on CO_2 and coal prices	0.5 – 0.8	27.5 €/ $MWh_{e,\ CHP}$	4 – 6 M€/a
Promotion of agrobiomass use: feed-in tariff based on CO_2 price	0.5	11 €/ $MWh_{e,\ CHP}$	1.5 M€/a
Investment subsidy a) New technology gasifiers *OR* b) (alternative: new technology biomass line)	2 (1)	40 % of the investment *OR* (40% of the investment)	total 40 M€ *OR* (total 20 M€)
Promotion of torrefied biomass/bio-oil/similar use: a) Investment subsidy for new upgraded biomass production plant demonstrations *AND* b) Feed-in tariff based on CO_2 and coal prices	0.6	40 % of the investment *AND* 27.5 €/ $MWh_{e,\ CHP}$	total 40 M€ *AND* 5 M€/a
Total renewable fuels - renewable energy (end use)	2.8 – 4.1 2.4 – 3.5		Production subsidy 10.5 – 12.5 M€/a Investment subsidy max. 80 M€

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