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Biomass and central receiver system (CRS) hybridization: Integration of syngas/biogas on the atmospheric air volumetric CRS heat recovery steam generatorduct burner

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Abstract

Central receiver systems (CRS) are a promising concentrated solar power (CSP) technology for dis- patchable electricity generation. The CRS levelized cost of electricity (LCOE) is usually increased by low power-block capacity factors or by high thermal storage costs. The economical turnover is still positive for the Portuguese case but depends on the bonus feed-in tariffs. On the other hand, with biomass existing feed-in tariffs and raising prices, the viability of current biomass power plants is at risk. To address these issues, several base case power plants and hybrid biomass/CSP options are analyzed: wood gasification, refuse-derived fuel pellets, biogas from a wastewater anaerobic digester, biogas from a landfill and natural gas.

The solution with lower LCOE was obtained for the hybridization of a 4 MWe CRS using an atmospheric volumetric receiver with biogas from an anaerobic digester using sludge from a wastewater treatment plant (WWTP). Different results would be obtained for the hybrid systems if different CRS technologies are used. The hybrid CRS/anaerobic digester power plant LCOE is 0.15 €/kWh, returning the investment in 13 years (assuming sludge collection and transport without cost) with the best net present value (15 million euro) and internal rate of return of all the hybrid options.

1. Introduction

1.1. Background

A network integration request call (PIP) was released in Portugal in 2009 for the integration of 28.5 MWe from concentrated solar power plants. This call aimed to building several CSP plants using different technologies (parabolic trough, central receiver, linear Fresnel, Stirling dish) in pilot scale from 1.5 up to 4 MWe [1]. Also, a call was released in Portugal for the construction of biomass power plants with an improvement in the feed-in tariff in 2010 [2,3]. These initiatives are part of the 2020 national strategic plan for renewable energies, where Portugal assumed to obtain 31% of the annual energy consumption from renewable sources by 2020 [4].

The Portuguese Algarve region is one of the premium European locations for CSP power plants. In addition to excellent solar re- sources (the solar direct normal irradiation (DNI) can achieve values of 2200 kWh m^{-2} $year^{-1}$ [5-7]), Algarve has great accesses and structures for an easy installation and support of a CSP power plant. Algarve has also significant yearly biomass resources: forest and crop wastes (1244 GWh), municipal solid wastes (425 GWh), biogas from waste-water treatment plants (219 GWh) and residues from agricultural and wood industry (30 GWh) [8]. A large part of these resources are unexplored, despite the premium feed-in tariff set by the Portuguese authorities for the last CSP-PIP call in 2009: 0.273 V/kWh (<5 MWe) or 0.267 V/kWh (>5 MWe) and for the biomass call: 0.109 V/kWh (<5 MWe) or 0.107 V/kWh (>5 MWe) [1,2,9].

1.2. *Volumetric air CRS*

One of the CSP technologies approved for the CSP e PIP call was an atmospheric (open) volumetric central receiving system. The typical optical concentration factor ranges from 200 to 1000 and plant sizes of 10-200 MWe, even though advanced integration schemes and economic sense are claiming for smaller units as well, with over 30 CSP power plants below 10 MWe installed power under construction/operation worldwide [10]. The power plant components can be structured into: i) steam cycle, ii) air cycle and iii) solar field. The solar field is composed by a heliostat field that focuses the solar radiation on the volumetric receiver. Air flows through the receiver, cooling its inner structure, and leaving it at ca. 700 ^{o}C [11]. The use of air as heat transfer fluid (HTF) presents advantages (availability, cost and toxicity) and disadvantages (low energy density and thermal conductivity) and influences the se- lection of the storage technology. In the Jülich commercial power plant a regenerator-type storage is used (passive storage) where air flows through a solid storage medium (e.g. ceramics) loading or unloading the storage by reversing the flow with axial blowers [12]. Afterwards, the hot air exchanges heat with water/steam in a heat recovery steam generator (HRSG) generating steam at 480-540 ^{o}C and 35-140 bar that feeds a steam turbine operating in Rankine cycle [11], Fig. 1.

The pressurization of the heat transfer fluid (using closed volumetric receivers) increases the HTF temperature, and allows using combined cycle power blocks, with enhanced power plant efficiency. Although some conceptual receivers were developed and some prototype power plants are being built [13,14], there are no fully commercial power plants with pressurized receiver configuration and they were not considered for the purpose of this work. The estimated levelized cost of electricity (LCOE) for the construction and operation of a pressurized volumetric CRS could reach grid parity [15], but long term operation is still unproved, while the LCOE of an atmospheric volumetric CRS operating in solar-only mode is still above grid parity [15]. One of the factors responsible for the high LCOE for this technology is the low power plant capacity factor, usually limited by the storage capacity, cost and size limitations.

1.3. *Biomass: gasification syngas and biogas*

Several national projects were approved for the biomass e PIP call, mainly for the construction of power plants using forest waste biomass, municipal solid wastes, and waste-water treatment plants or animal residues biogas. There are several biomass conversion technologies (thermo-chemical, bio-chemical and physical- chemical) that can be designed specifically for each biomass resource. The thermo-chemical conversion processes are mainly applied to woody biomass, energy crops, agricultural or industrial waste in solid state and with low humidity. This is the most conventional approach in commercial electricity generation power plants, e.g. biomass combustion boilers; biomass gasification (still in early commercial stages but have promising performances). However, electricity generation is not the only application; there are plants using gasification to generate a mixture of methanol, syngas, electricity and heat with conversion efficiencies up to 73% [16,17] or using gasification/combustion to supply a municipality with electricity and heat with conversion efficiencies up to 81% [18]. These applications are mainly from woody biomass, i.e. forest residues (with possible positive impact in the forest, mainly regarding wild fire prevention); and agricultural or industry residues (with a positive impact on the local industries, adding value to these by-products).

When biomass has higher water content, or comes from animal or urban residues, the most applied biomass conversion technologies are based on bio-chemical processes such as anaerobic digestion. These digesters are largely applied in recent waste-water treatment plants and landfills with great benefit to the environment and with economical viability of the waste-water treatment plant or landfill. As biomass has low energy density (when compared to fossil fuels), large volumes of biomass are necessary to have a significant generated power. Both biomass power plant conversion technologies (thermo-chemical or bio-chemical) require biomass consumption and collection to be done locally (max. 50-80 km [19]). Otherwise, the collection and transport cost could easily escalate and surpass the biomass cost. The necessity of a large biomass stock at a stable price is one of the biggest problems for the construction and operation of biomass power plants. Another difficulty is the low feed-in tariff set by the Portuguese authorities for the technology.

Despite the positive environmental impact and the valorisation of the residues and resources, the number of successfully implemented projects approved in the Biomass and CSP ‒ PIP calls was low, and currently there are available areas with reasonable solar and biomass resources and with conditions for electricity network integration. CSP hybridization with biomass could solve these problems, maintaining the renewable objective, reducing the high feedstock requirements of a traditional biomass power plant and increasing the capacity factor of a traditional CSP power plant. This hybridization opens a completely new market both for CSP and biomass. CSP-biomass hybrid solutions can be a good solution for decentralized electricity networks and a viable alternative to sup- ply remote populations with electricity and heat.

2. Methodology

2.1. *Simulation tools*

The base cases and hybrid solutions were designed using three software tools: Ebsilon Professional [20] for the air cycle, steam cycle and storage, HFLCAL for the solar field and solar fluxes [21] and Excel for working data and defining the power plant economics. For each time step, Excel gathers the solar field performance from HFLCAL and sends this information to Ebsilon, running the heat transfer fluid and obtaining power block performance. Although larger power plants (10 MWe and 50 MWe) should originate better performance and economical indicators, the immediate objective was to deter- mine the best solution for hybridization of a 4 MWe CRS, responding to the Portuguese PIP call specifications. A set of independent CRS and biomass power plants were designed for comparison and validation purposes (base cases); for comparison purposes, similar power blocks were considered for the base cases. Using the components from these power plants several CRS-biomass hybrid solutions were developed.

2.2. *Base cases*

The process to find the optimal configuration for a 4 MWe atmospheric volumetric CRS power plant depends on several variables and is highly iterative since all variables are interdependent. Several solar-only CRS power plant configurations were optimized [22] and are used as base cases for hybridization

- CRS#1 ‒ solar only power plant (4 MWe) with a 1.25 solar multiple and 2 h storage, design DNI 750 W/m^2 and receiver area of 60.0 m^2 with receiver peak flux of 950 kW/m^2;
- CRS#2 ‒ solar only power plant (4 MWe) with a 1.75 solar multiple and 6 h storage, design DNI 750 W/m^2 and receiver area of 60.0 m^2 with receiver peak flux of 950 kW/m^2;
- CRS#3 ‒ solar only power plant (4 MWe) with a 1.25 solar multiple and 3 h storage, design DNI 750 W/m^2 and receiver area of 60.0 m^2 with additional

10% tolerance in the receiver peak flux;

For Faro (Algarve) conditions, the best solar only power plant configuration is a 1.25 solar multiple, 2 h storage, with a 4 MWe power block operating under Rankine cycle (nominal conditions steam at 480 °C and 80 bar), working under a control strategy that uses the daytime solar power to run the power block storing the excess heat. This stored energy is used to cover solar transients and extend operation until storage is empty [22].

The integration of biomass in the power plant can be done in the air cycle or in the steam cycle. The biomass integration in the steam cycle was analysed in Ref. [23] using a biomass steam boiler. The base case for this power plant was a 4 MWe forest waste burning plant:

- Forest residues burning (FRB) – 24 h/day operation forest waste (NCV = 13.8 MJ/kg) direct burning power plant with a 4 MWe power block operating under Rankine cycle;

The forest residues boiler technology is mature and has good fuel flexibility, but is usually associated with moderate efficiencies and large start-up and response times to compensate typical solar transients (increased dumping in hybrid solutions). A fast response biomass based technology is biomass gasification with gas storage. Several early commercial prototypes had problems with gas cleaning (tar and ash removal), but later biomass gasification power plants have been operating without major breaks [24]. Despite this, fuel flexibility is still an issue, and a constant properties fuel should be selected for viable long term operation. Biomass forest residues are not a resource with constant proprieties and usually have high moisture content, sands and other contaminants. Due to this, alternative biomass resources were considered: wood residues or biomass pellets. The pellets have lower moisture content and are more uniform in terms of proprieties, but present a significant extra cost to the power plant. Wood residues have a lower cost than pellets and a higher net calorific value (NCV) than forest residues.

The Güssing power plant is a successful case for biomass gasification. It is designed to supply Austrian Güssing district with electricity and heat. The Güssing fluidised bed gasifier consists of two zones: a gasification zone and a combustion zone. The gasification zone is fluidised with steam which is generated by waste heat of the process, to produce a nitrogen free syngas. The combustion zone is fluidised with air and delivers the heat for the gasification process via the circulating bed material. The produced gas is cooled, cleaned and used in a gas engine. The heat produced in the process is partly used inside, e.g. for air preheating, steam production, etc., and the rest is delivered to the district heating system. Based on the reported performance [18,25], the Güssing FICFB (fast internal circulating fluidised bed) gasifier concept was modelled and validated. Because the power block of commercial available atmospheric volumetric central receiver systems is composed by an HRSG and a steam turbine, and the objective of this study is the integration of biomass in CRS, the base case considers that the produced syngas is integrated in the HRSG (duct burner) coupled with a steam turbine:

- Pellets gasification (PG) ⊖ gasifier operating with air/steam, a 4 MWe Rankine cycle power block operating 24 h/day using biomass pellets (NCV ⊖ 18.6 MJ/kg);
- Wood residues gasification (WG) ⊖ gasifier operating with air/ steam, a 4 MWe Rankine cycle power block operating 24 h/day using wood residues (NCV ⊖ 16.2 MJ/kg);

A different possibility is to use refuse-derived fuel (RDF) from municipal solid waste pellets (mainly plastics and biodegradable waste). The gasification of these pellets is an interesting solution to solve the environmental impact of municipal solid waste. One of the world references in this technology is the 20 MWe Fukuyama RDF gasification plant [26]. Another reference is the 6.7 MWe Greve in Chianti RDF pellets gasification power plant. However, several operational problems occurred in this power plant, namely with gas cleaning and maintaining gas properties. Based on the Chianti RDF and Gasifier properties, a 4 MWe power plant was considered:

- Refuse-derived fuel gasification (RDF) ⊖ RDF pellets gasifier (NCV ⊖ 17.2 MJ/kg) coupled to a 4 MWe power block operating under Rankine cycle operating 24 h/day;

Locally there is also an interesting potential of biogas generated from a waste water treatment plant (WWT) and landfills. The biogas generated from the landfill has different characteristics compared with the biogas generated by a wastewater anaerobic digester [27]. For both cases the local plants are insufficient to sustain the 24 h annual operation at nominal power (4MWe). For comparison purposes, a biogas waste-water anaerobic digester was considered:

- WWT biogas digester (BD) ⊖ biogas WWT digester (NCV ⊖ 20 MJ/kg) coupled to a 4 MWe power block operating under Rankine cycle operating 24 h/day;
- Landfill biogas (BL) ⊖ landfill biogas (NCV ⊖ 12 MJ/kg) coupled to a 4 MWe power block operating under Rankine cycle operating 24 h/day;

A different approach is to turn household garbage into biofuels and biochemicals. The Edmonton's Waste-to-Biofuels and Chemicals Facility is the first industrial scale waste-to-biofuels facility in the world, annually converting 100 thousand tonnes of municipal solid waste into 38 million litres of biofuels and chemicals [28]. An alternative or supplement to syngas is the natural gas. Natural gas Rankine and combined cycle power blocks are an established technology, but the renewable goal would be lost. A Rankine cycle power plant, using similar power block configurations was considered, substituting the feed from syngas and biogas to natural gas from local low pressure pipelines:

- Natural gas burner (NG) e natural gas burner boiler power plant with a 4 MWe power block operating under Rankine cycle operating 24 h/day using natural gas (NCV e 38 MJ/kg);

The commercial power plants running on natural gas normally use combined cycles scaling from 50 MWe up to several hundred of MWe. The use of combined cycles in a power scale of 4 MWe is not usual as the HRSG and steam turbine would be quite small resulting in higher capital expenditure (CAPEX), without significant increase in power block efficiencies. Thus, it was selected a power plant configuration using a Rankine Cycle.

2.3. *Hybrid solutions*

Using the base case components described before, several hybrid solutions were developed. The objective for biomass integration into a CRS is to support the solar transients and increase the power plant capacity, increase the operation period, analyse the impact of hybridization in the CAPEX, in the generated electricity cost and in the investment return. The integration of the biomass/ biogas/syngas in the air cycle of a CRS can be done in several points,

e.g. via a duct burner in the HRSG, via a combustion chamber of a gas turbine or gas engine. Fuel contaminants are a problem for all types of power systems. Gas turbines are especially sensitive to particulate matter, water and metallic contaminants [29]. Although fuel conditioning and handling systems should be considered for all combustion systems (to minimize fuel quality variations), in general gas turbines operate at higher average pressures and temperatures and are more prone to erosion and corrosion. The integration of a gas turbine would also imply a significant investment (despite the expected efficiency increase) and would imply a significant increase of hybrid fuel consumed (lower solar fraction). Also, the CRS design power (4 MWe) is low for the implementation of commercial combined cycle power blocks and the cost/efficiency gain with an implementation of a micro gas turbine or small gas engine combined with a small steam turbine should be further studied. Comparing the integration options, the integration via an HRSG duct burner is a robust solution, with predicted lower impact due to possible contaminants of the biomass syngas, and reduced investment. These reasons support the selection of syngas/biogas integration via a duct burner in the HRSG, Fig. 2.

Different options can be considered in future studies, e.g. finding the optimal control strategy for the hybrid power plant, utilization of combined cycles, utilization of organic Rankine cycles or power plant optimization for smart power generation - adjusted network demand/supply electricity generation, or utilization of CSP and biomass to generate chemical products such as hydrogen [30]. The largest commercial CSP-biomass power plant worldwide is the Termosolar Borges is Spain [31]. This power plant uses a parabolic trough solar field and biomass boilers to generate 22.5 MWe. This is a hybrid solution that uses mature technologies and has advantages such as using a single heat transfer fluid and lower CAPEX. How- ever, the biomass boilers start-up and transient response is slower when compared to the CRS hybrid biogas/syngas and is less efficient than biomass gasification. For the integration via duct burner in the HRSG (Rankine cycle), different fuels and CRS combinations can be considered for the hybridization, Fig. 3.

The first two design options at Fig. 3 consider a FICFB gasifier integrating the syngas generated in a duct burner of the CRS HRSG. The CAPEX for the Güssing power plant was 10 million euro and uses a combined heat (4.5 MW) and power (2 MW) gas engine [25] e CAPEX per installed electric power of 5000 €/kWe. Different references indicate equipment costs for a CFB gasifier and internal combustion engine ranging from 1850 to 3460 €/kWe [32]. A pressurized fluidized bed gasifier with gas clean up and steam injected gas turbine engine can have a gross conversion efficiency up to 43% [33] and a CAPEX per installed electric power cost of 5325 €/kWe [33].

The model used for equipment and CAPEX estimation was based on Caputo et al. [34], and for the Güssing power plant (2 MWe) resulted in a CAPEX of 5328 €/kWe (+6.6% than the Güssing 2 MWe power plant cost); for a 4 MWe net power plant the equipment cost is 3175 €/kWe and the CAPEX is 4216 €/kWe, Table 1. The operation and maintenance (O&M) costs for the Güssing power plant are 1.3 million € per year [25] (including the biomass cost and ash disposal, 66 €/ton [35]). Ash recycling or disposal costs for Sweden are respectively 55-66 €/ton (recycle) and 11-44 €/ton taxes (Landfill deposit) [36], dependant on distance and quantity; for Portugal, landfill taxes vary between 1 and 6 €/ton [37]. The model used to estimate the ash disposal cost was based on Caputo et al.[34] and defines a cost of 62 €/ton for ash transport and a 24 €/ton cost for ash disposal [34].

One of the major issues of biomass power plants is to have access to a competitive and stable biomass cost. To address this challenge, the power plant is usually located close to the biomass source and the biomass price is set for a long-term contract with different suppliers. There are several indexes, e.g. for the pellets price, depending on the origin and destination of the biomass [38e40], but all recording high volatility in recent years. Also the biomass market is demand oriented and there is a significant in- crease in domestic use of biomass (mainly pellets), which influences the price for the industrial applications. The biomass price for industrial applications in recent years in Germany is 210e250 €/ton [39], while in Austria is 185-220 €/ton [38] and the PIX Pellet Nordic Index varied from 120 to 150 €/ton [40]. Based on national quotations, the best biomass pellets spot price for May 2013, including delivery, was 200 €/ton [41]. A different approach is to use wood, locally collected from forest, and industry residues, as in the case of Güssing power plant, with a lower cost, 24-55 €/ton (0.007-0.016 €/kWh [25]), but also with lower calorific value. This biomass cost is in line with national forest residues cost - 27 €/ton.

Municipal solid waste (MSW) is collected from the municipalities and is, in most cases, disposed in a landfill. The use of this waste means a significant positive wealth and logistic solution. The capital investment of Chianti RDF power plant (6.7 MWe) was 3500 €/kWe [42]. Using the economical model (based on Caputo et al. [34]), the CAPEX for the Chianti RDF power plant is 3235 €/kWe (less 7.6% than the Chianti RDF 6.7 MWe power plant cost); for a 4 MWe net power plant the equipment cost is 3204 €/kWe and the CAPEX is 4260 €/kWe, Table 1. This is a similar CAPEX to the 4 MWe turnkey RDF solution from Chamco [43], which presents a cost of 3977 €/kWe (less 6.6% than the 4 MWe cost model used). In addition, the RDF selection and treatment (eventual pelletizing) represents a cost for the power plant (10-21 €/ton of RDF [44]), depending on the process configuration and MSW composition. Annual O&M costs differ significantly from different references: for similar Termiska Processer power plant technology applied to the Chianti power plant but with larger power (75 MWe) O&M are 21% of the CAPEX, with waste disposal cost included in the O&M cost [42]; for the Chamco solution the O&M are estimated slightly above 13% of CAPEX per year [43]; a different study from Klein [45] pre sents an annual O&M cost for RDF gasification power plants from 9 to 20 % of CAPEX, including a 38 €/ton ash disposal cost. The used O&M costs are 12% of the CAPEX (including a 5% of CAPEX fix O&M cost, a variable O&M cost of 21 €/MWh and a 62 €/ton ash transport and 6 €/ton disposal costs).

In a different perspective, biogas can be recovered from landfilled MSW. The biogas composition and rates are dependent on the composition of the MSW. The Landgem model [46] was used to describe the emissions of biogas from MSW landfills and is based on a first-order decomposition rate equation of the waste mass accepted by the landfill, the methane generation rate (k) and the potential methane generation capacity (Lo). For 30 year operation and using average inventory recovery estimates (k= 0.04 year^{-1}; Lo 100 m^3/ton) the consumption of MSW to generate the necessary biogas to run the 4 MWe power plant is 200 10^3 ton per year (total landfill capacity of 6000x10^3 ton). The average CAPEX for a landfill biogas power plant is 1575-2025 €/kWe [32], with equipment cost ranging from 1010 to 1125 €/kWe [32] and a biogas extraction cost of 0.02 €/ton [32]. The region has two landfills with 1900x10^3 ton and 1800x10^3 ton capacities, which are still insufficient to feed the 4 MWe hybrid power plant; however, the recovery of biogas from landfill and the hybridization with a CRS can be an interesting for countries with good solar resources and large landfills. The same perspective was applied to the biogas from a WWTP digester. About 18.3 L of biogas (on average) can be generated per inhabitant daily [47]. To supply the hybrid 4 MWe power plant, the WWTP should serve a population of over 3 million of inhabitants, although the two largest WWTP in the area serve only 140,000 and 50,000 inhabitants. As the digester retention time should be above 15 days [47] this also implies large digesters and quantities of sludge that are very difficult to collect locally, so additional sludge from a nearby WWTP should be transported to the local with supplementary costs. The predicted CAPEX is dependent on the selected digester/power block technologies but, due to the dimension, is significantly high (2100-4725 €/kWe [32]), with equipment costs of 1240-1725 €/kWe [32]; two possible scenarios were analysed: starting the process with sewage sludge or directly using available biogas with no additional cost. The WWTP biogas generation O&M costs are similar to a conventional biomass power plant (2.1-7% of CAPEX-Fixed; 3.2 V/MWh Variable [32]) but lower than for a landfill power plant (11-20% of CAPEX [32]). The digestate disposal cost can represent a profit for the plant (if sold as fertilizer, with a commercial value of 14 V/ton), or an expense for the plant (if supplied for free to the farmers the power plant has to cover the spreading costs of 10 €/ton, or if disposed the power plant has an estimated cost of 55 €/ton) [48].

Commercial power plants in Portugal using natural gas have higher design power (centralized solutions using combined cycles) or use cogeneration [49]. Despite not being the optimal performance solution for a natural gas power plant, a 4 MWe power plant operating a steam turbine fed by a steam generator with a natural gas burner was considered. A natural gas local network is available and so it is possible to connect the power plant to this gas network. The feed-in tariff for large consumers in Portugal is composed by a fixed daily and monthly cost plus the natural gas consumption (with different prices for the peak and empty hours) [9]. The annual average natural gas price for the 4 MWe power plant base case is presented in Table 1.

Two approaches were used to analyse the economical impact of the power plants: Levelized cost of electricity and cash flows analysis. LCOE were calculated according to equation (1), using *r* of 8% and a 30 year power plant lifetime expectance (*n*).

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{\mathrm{CAPEX}+K_{O\&M}+K_{\mathrm{fuel}}}{(1+\mathrm{r})^{t}}}{\sum_{t=1}^{n} \frac{E_{\mathrm{net}}}{(1+\mathrm{r})^{t}}} \quad (1)$$

The cash flows analysis allows calculating the investment return rate, net present value and payback period. The cash flows analysis considered: a 30% own capital, a 20-year loan with an interest rate of 8%, a 1% annual insurance rate (included in CAPEX), a linear amortization for 20 years, current national profit taxes and a 1% of power degradation. Both economical models (LEC and cash flows) results were subject of a sensitivity analysis to determine the impact of variations in the parameters estimative. All costs have been updated for 2012 euro.

3. Results and discussion

A CRS operating in solar-only mode has several advantages comparing to other renewable energies technologies, but also some limitations. CRS using efficient thermal energy storage (TES) can decouple the power generation from the solar power. Nevertheless, a 24 h/day operation requires an over-sized solar field and receiver as well as large TES devices (in the case of atmospheric air technology this has a high cost and size) which reflects in higher CAPEX and LCOE.

Biomass-only power plants also have the dispatchable electricity generation characteristic and usually operate in 24 h/day mode. The major issues with biomass-only power plants is the biomass collection and transport (limited to the power plant surroundings, otherwise the cost is unsustainable). The biomass plant is in most cases limited by this factor, making impossible to use larger and more efficient power blocks. Biomass price stability and availability is also an issue, as they affect the power plant operational profit mainly because the feed-in tariffs are quite low.

Several solar-only and biomass-only power plant configurations were considered. The Biomass and CRS base case performance and cost are presented in Table 2. To make the results directly comparable, all the power plants use similar nominal steam conditions and power blocks. These power block conditions were optimized considering several power blocks and analyzing their impact on a CRS power plant performance and cost. Using this power block, the optimization of the solar-only CRS was made assuming different solar multiples, thermal storage device capacities and control strategies to analyze the power plant performance and cost impact. Power plant configurations CRS#1 and CRS#2 are two CRS optimized configurations for small and large storage capacities, while CRS#3 has the same configuration of CRS#1 but an amplified peak receiver flux, Table 2.

The steam turbine nominal operating conditions were consider to be similar for all options and the power plant was considered to have an availability of 90% [50] for a 24 h/day operation and 96% for solar-only operation. Different biomass sources were considered for the optimization of the biomass-only plant: forest residues, biomass pellets, wood residues, refuse derivate fuel pellets (RDF), biogas from a waste water treatment plant (WWTP) and biogas from a landfill. Forest residues biomass was used to feed a combustion boiler; biomass pellets, wood residues and RDF were used to feed a gasifier and generate syngas; it was also considered the generation of biogas from landfill and WWTP and to use natural gas form the network, respectively with the compositions presented in Table 3.

Natural gas has the highest NCV, while the WWTP biogas has a composition closest to natural gas but with higher CO_2 concentration and lower NCV. The syngas composition from gasification depends on the biomass source and technology used; steam gasification can originate streams with high concentrations of H_2 and low concentrations of N_2, whereas atmospheric air gasification originate streams with lower concentrations of H_2 and more N_2, which lowers the calorific value of this syngas.

The hybrid solar/biomass power plant capacity factor is larger when compared to a solar-only power plant, having the possibility of 24 h/day operation and 100% renewable goal for power on demand option. The biomass consumption is reduced for a similar design power, or for similar biomass annual feeds, larger and more efficient power blocks can be used; furthermore, the hybrid power plant can have a feed-in tariff higher than the biomass-only power plant.

Hybrid CSP biomass power plants can be an interesting solution centralized electricity generation and for off-grid locations. The social impact of a power plant with these hybrid characteristics is also interesting because the resources can be collected and trans- formed locally, contributing to the local economy, with creation and fixation of jobs. The hybrid power plant can also use a large range of biomass sources in the form of biogas or syngas to be integrated in a duct burner updraft of the HRSG. Duct burners are quite efficient and can be designed for a large range of fuels, satisfying emission limits. However, the reliability of these components can be an issue, both in terms of maintenance requirements and component failure, in particular for high temperature values of the burner body, which may cause significant thermal stresses and even cracks or permanent deformations. Moreover, the syngas metal contaminants (e.g. Co and Ni) should be controlled because they can endanger the duct burner system (including all piping) operation, e.g. by decomposition in the supply manifold, as well as in the injection nozzles causing a long-term destruction of the pipe due to the local con- centration of thermal stresses; or causing the injection nozzles occlusion, which requires monthly stops of the plant for maintenance [51]. The fuel quality control is therefore a vital aspect for the power plant viable operation.

For all hybrid power plants, a gasometer was considered to store the generated syngas or biogas, so it is available to provide energy to cover the solar transients and extend operation. The gasometer also allows the digester/gasifier to be operated without significant transients. Although gas storage is not mandatory, the circulating fluidized-bed gasifier have high thermal inertia, and intermittent

Operation of the gasifier is not recommended [52], so gas storage acts as a buffer to the gasifier operation. The same principles apply to the anaerobic digester system and the landfill. In commercial solutions, also a natural gas backup is recommended to support eventual maintenance or lacks of biogas/syngas.

The complementarity of both technologies increases the power plant capacity factor and improves operational performance, as the duct burner has quick response times, and maintains the HRSG temperature controlled so steam is fed consistently to the turbine. Performance and cost analysis data for the CRS and biomass integration via a duct burner in the HRSG (Rankine cycle) are shown in Table 4.

The hybrid solutions using wood pellets (PG#CRS) have the highest LCOE, mainly due to the pellets high cost and despite the lower consumption. The producer gas generated from wood pellets has higher NCV when compared with the same gasifier technology using wood residues (WG#CRS), but the overall feedstock to electricity efficiency is not significantly increased. WG#CRS option has an favourable LCOE of 0.17 V/kWh, which is 0.06 V/kWh lower than the solar-only optimized power plant (CRS#1) but, for this scale, the LCOE is slightly higher than the forest residues biomass boiler integration in the steam cycle of the CRS. The gasification conversion efficiency is higher but, due to the higher wood residues cost than the forest residues biomass and the higher CAPEX, the LCOE for WG#CRS#3 is higher than FRB#CRS#3.

The pelletized RDF has lower cost (only selection and pelletizing costs were assumed) and can feed an air gasifier power plant with similar CAPEX to the wood residues steam/air gasifier power plant. The generated RDF syngas has lower NCV and implies larger maintenance, so the power plant LCOE is higher. If we analyse the cash flow for the first year of RDF#CRS#1 operation, the power plant expense is over 2.7 million euro and generates a profit of 2.1 million euro (if the generated electricity is sold at 0.148 €/kWh), resulting in the operational loss of 0.6 million euro. In case the waste used to feed the power plant was transported and dumped into a landfill without reuse this would imply an annual cost of over 2 million of euro (33x103 ton). This means the municipality got a investment reduction, for MSW disposal, of almost 1.4 million of euro (the difference from operating the power plant plus the expense cut with garbage dumping) that is the biggest advantage of using RDF for gasification.

The WWTP anaerobic digester base case option is designed for large cities with centralized sewage collection systems. If the WWTP has capacity to supply a power block with $22x10^3$ ton per year of biogas the LCOE would be low (0.08 €/kWh). If it is necessary to collect sewage sludge from several smaller WWTP into a centralised digester, additional costs will apply; for example, if required to transport 30% from a nearby WWTP (within 30 km distance), an additional CAPEX of 3.2 million euro is estimated. This investment is related to the acquisition of transportation trucks and build a loading/discharging area with additional annual O&M costs of 1.1 euro per m^3 of sludge, based on US EPA [53]; this would increase the LCOE of the BD base case power plant from 0.08 €/kWh to 0.11 €/kWh. In a different scenario, if the biogas is already available at no cost (e.g. biogas from large livestock with already implemented manure collection systems, like dairy or pig farms) the CAPEX would be lower and the LCOE would be even lower (0.06 €/kWh for the base case). However, for dairy/pig farms or WWTPs, this is a very large plant and for this scale (in most cases) it is necessary to transport sludge from other plants (with additional cost). The hybridization with CSP can reduce the biogas consumption but with significant increases in the LCOE (40e70%). However, as for each technology a specific feed in tariff is obtained, to fully analyse the impact of the hybridization into the economical balance of the power plant a detailed cash flow was carried out for the base cases (Table 5) and hybrid options (Table 6).

The economical analysis is affected by suppliers' quotations and the references selected for the considered options and should be used only as an indicative of the impact of the different technologies in CRS hybridization. The Portuguese feed in tariff is set for each project by the national authorities, using a calculation formula [54] set for renewable electricity generation, and its adaptability for hybrid power plants is yet not defined; so, a weighted average from the energy generated from CSP and biomass was used. The impact of national taxes and inflation during the power plant life cycle is significant and can reduce the investment interest.

The base cases for gasification (wood pellets, wood residues and RDF) do not originate positive investments due to the low feed-in tariff and high CAPEX. The CRS hybridization with biomass wood residues gasification improves the life-time cash flow of the power plant, reducing biomass consumption by over 11 thousand tons per year compared to the base case. The hybrid power plant is economically viable to operate under the Portuguese scenario, despite having a low attractiveness, with an IRR of 5.5% and an NPV of 3.3 million euro (WG#CRS#1). A hybrid power plant (WG#CRS#2) with higher solar share decreases the biomass consumption by 16 thousand ton per year but, the investment is less attractive because the payback period is higher and the IRR is reduced below the assumed inflation. A forest residues biomass boiler can be integrated in the steam cycle of a CRS with an LCOE of 0.144 €/kWh, IRR of 6.8%, NPV of 7.9 with a payback of 21 years [23]. If waste transport and disposal is necessary, the LCOE of this power plant would increase to 0.16 €/kWh, the IRR and NPV reduce to 4.4% and 0.8, respectively, and the investment will have a payback of 28 years. The forest residues steam boiler integration in a CRS would be less profitable than the gasification of biomass and syngas integration in a duct burner of a CRS HRSG. The selection of a biomass type with stable properties is important to avoid operational problems; biomass gasification technology is more complex and still less mature than a biomass boiler, and in the case of biomass gasification, lower quality/homogeneity biomass can origin instabilities to the process and higher maintenance costs. Despite that, biomass pellets gasification does not origin a positive cash flow, considering the Portuguese feed in tariff.

MSW is a problem in many countries due to a lack of structures for collection and disposal/reuse. The economical valorisation of MSW, by generating electricity, can provide funds to help the amortization of MSW collection and storage costs. Also a structural effort to reuse and recycle the MSW is essential in these countries (with priority over energy from waste) to reduce the total waste disposed in landfills. The LCOE for RDF gasification is higher than to generate biogas from a landfill; the main reason for this is that, for the deposit in the landfill case, the main equipment costs are the gas extraction, processing and power block (landfill construction and maintenance was not considered); while for the RDF gasification it is necessary to acquire more expensive equipments for triage and pelletizing of the MSW, gasification, gas processing and power block. The Portuguese landfills have a special tariff for the biogas, which makes the investment more attractive than RDF gasification. The investment in a base case RDF gasification or hybrid with CRS, with the actual feed-in tariffs, has negative economic contours and is only possible in a perspective to reduce the waste disposal costs and the dimension of otherwise necessary landfills. The biogas from recovery from landfills has high costs and maintenances and, for the actual base case feed-in tariff, the power plant operation generates losses, despite being a very large landfill (only possible in a few locations worldwide); from this perspective, the hybridization with a CRS can reduce the biogas consumption by 14 thousand ton per year from the base case (BL#CRS#1) and as the feed-in tariff would increase, the investment would be favourable with an IRR of 7.4% and a payback period of 20 years.

The use of sludge to feed an anaerobic digester generates a high NCV biogas from sludge (without transport cost) and beneficiates from the highest (biomass based) feed-in tariff. However, as in the case of the landfill biogas, the necessary WWTP biogas to feed the 4 MWe power plant (base case) implies a large WWTP only possible in a few locations worldwide; alternatively, it would be necessary to collect sludge from different WWTP into a centralized anaerobic digester, with additional costs. Hybridization with CSP can allow a WWTP downsizing, keeping the LCOE at 0.15 €/kWh, with an IRR of 11% an NPV of 15 million euro and a payback period of 13 years.

Natural gas could also be used to fire the duct burner and it is the solution with lower CAPEX. Nevertheless, due to the cost of the fuel, lower conversion efficiency than a standard combined cycle plant, and national taxes (it would represent almost 70% of the operational expenses e ND#CRS#1) and the low market electricity feed- in tariff it is unviable to hybridize the CRS fully with natural gas. However, in several countries (and only in a small percentage) it is possible to use natural gas to start up and support small solar transients without reducing the bonus electricity tariff. This could be an appealing solution (if it is also allowed by national authorities) because natural gas can also be used to co-fire all the hybrid solutions and be a safeguard in the case of lack of biogas/syngas supply.

4. Conclusions

Hybrid biomass and CSP power plants are interesting option for future dispatchable renewable electricity generation. CRS major problems are the moderate capacity factors or high TES costs, while the biomass major problems are the necessity to build a large biomass collection structure, the volatility of the biomass price and the low feed-in tariffs. The hybridization of these technologies increases the power plant capacity factors (when compared to a solar only CRS) and reduces the biomass consumption (when compared to a biomass only power plant) still generating a dispatchable electricity flow with positive economical indicators.

The LCOE for the CRS base case is 0.23 €/kWh and the best base case LCOE is the WWTP anaerobic digester with 0.08 €/kWh. For biomass integration into the air cycle of a CRS, the lower LCOE options are the hybridization of a 4 MWe CRS using an atmospheric volumetric receiver with biogas from a WWTP or with natural gas (LCOE of 0.15 €/kWh), with landfill gas (LCOE of 0.16 €/kWh) or with wood residues gasification (LCOE of 0.17 €/kWh). Different results would be obtained for the hybrid systems if different CRS technologies are used. Because the Portuguese bonus feed-in tariff is calculated for each renewable energy technology, some of these power plant configurations have negative economical turnovers. The hybrid power plant investment with best payback period is the hybridization with an anaerobic digester, using sludge from a waste-water treatment plant. This power plant returns the investment in 13 years (sludge collection and transport assumed without cost), presenting also the best net present value (15 million euro). However, for the 4 MWe scale, WWTP or landfill biogas would only be possible close to large cities (few limit cases) with centralized plants capable of generating sufficient quantities of sludge or MSW. A different biomass CRS hybridization technology (which can be applied in a larger number of cases) that presents favourable LCOE is the gasifier working on wood residues (WG#CRS#1 - LCOE of 0.17 €/kWh), which can reduce the biomass consumption by 11,000 tons per year compared to the base case, making biomass gasification economically viable to operate under the Portuguese scenario, despite having a low attractiveness, with an IRR of 5.5% and an NPV of 3.3 million euro.

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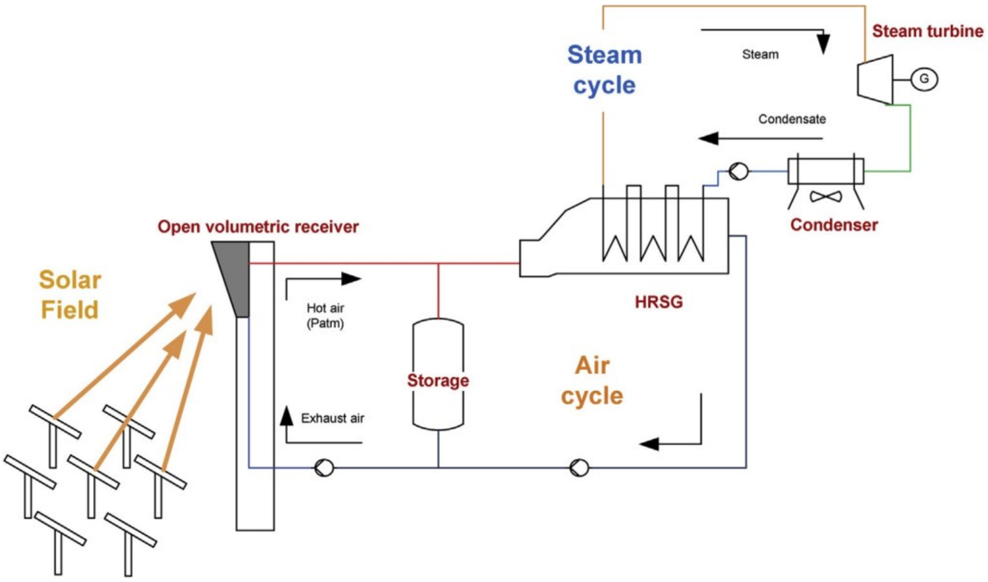

Fig. 1. Atmospheric volumetric CRS power plant configuration.

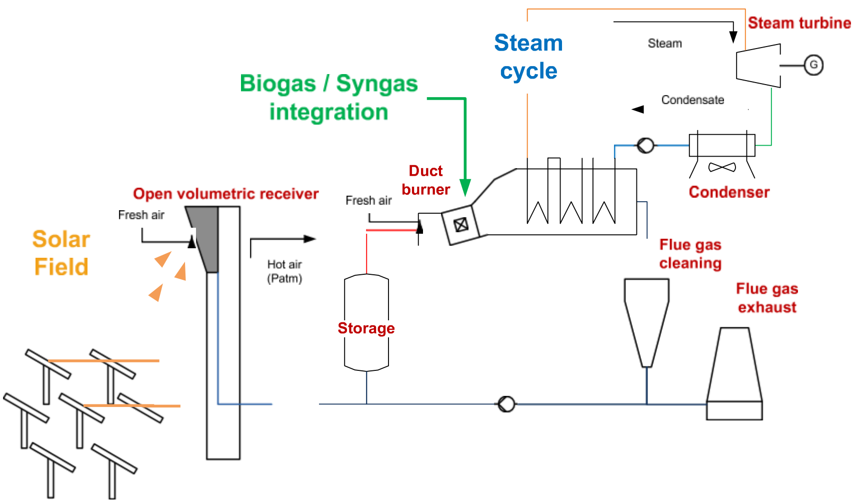

Fig. 2. Integration of biomass on CRS power plant air cycle, on a duct burner in the HRSG.

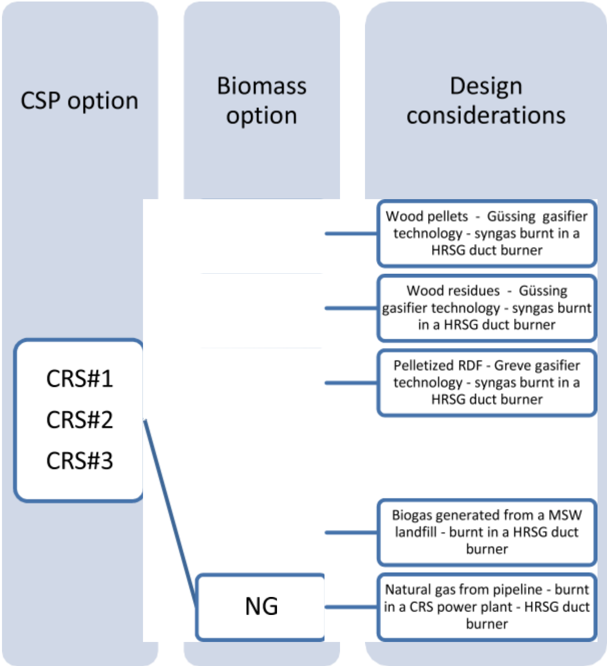

Fig. 3. Hybridization options for the considered CRSs.

Table 1

Cost considerations for the base cases.

Plant designation	CAPEX reference					
	Biomass cost (€/ton)	Equipment Cost (€/kW)	Power plant CAPEX (€/kW)	O&M costs		Waste disposal cost (€/ton)
				Fixed (% of CAPEX)	Variable (€/MWh)[c]	
CRS#1	n/a	3800	4800	3%	3	n/a
FRB	26	2800	3400	5%	3	86
PG	200	3175	4216	5%	3	86
WG	40	3175	4216	5%	3	86
RDF	15	3204	4260	5%	21	68
BD	n/a	1240–1725	3790[a] sludge 2685[a] biogas	5%	3.2	10
BL	0.03*	1010	1845[b]	15%	n.a.	n/a
NG	248	780	920	10%	3	n/a

n/a – not applicable; n.a. – not available; * – €/m^3.

[a] Average equipment cost and CAPEX based on a case study for a 1 MWe internal combustion engine, using biogas from anaerobic digester using sludge provided to the power plant without collection and transport cost. Sludge disposal cost not included.

[b] Average equipment cost and CAPEX based on a case study for a 5 MWe internal combustion engine, using biogas from landfill. Biogas collection equipment not included (cost of collection considered under biomass cost).

[c] Not including waste disposal.

Table 2
Biomass and CRS base case performance and cost.

Plant designation	Solar multiple	Storage	Feedstock	Biomass consumption (Ton/year)	Generated electricity (GWh/year)	Solar fraction	Feedstock to electricity efficiency (net)	LCOE[e] (€/kWh)
CRS#1	1.25	2 h	CSP only	0	11.6[a]	100%	10%	0.23
CRS#2	1.75	6 h	CSP only	0	16.1[a]	100%	9.5%	0.24
CRS#3	1.25	3 h	CSP only	0	12.3[a]	100%	11%	0.23
FRB [24]	–	–	Forest residues	32×10^3	31.6[b]	0%	26%	0.11
PG	–	–	Biomass pellets	29×10^3	32.0[b]	0%	23%[c]	0.26
WG	–	–	Wood residues	32×10^3	32.0[b]	0%	23%	0.12
RDF	–	–	RDF	35×10^3	31.9[b]	0%	19%[c]	0.14
BD	–	–	Biogas WWTP	22×10^3	32.4[b]	0%	26%[d]	0.08
BL	–	–	Biogas landfill	37×10^3	32.4[b]	0%	26%[d]	0.10
NG	–	–	Natural gas	12×10^3	32.4[b]	0%	26%[d]	0.13

[a] 96% plant availability.
[b] 90% plant availability.
[c] Pelletizing process efficiency not considered.
[d] Biogas/natural gas generation and/or transport process not considered.
[e] For a 30 year life time, annual 8% dept interest rate and 1% annual insurance costs [15].

Table 3

Biogas and Syngas calculated compositions.

Syngas composition	Technology					
	Steam/air gasifier		Air GASIFIER	Digester [27]		Network [27]
	Biomass pellets	Wood residues	RDF pellets	Landfill	WWTP	Natural gas
H_2 (% volume)	44	39	8.6	0	0	–
CO (% volume)	25	25	8.9	0	0	–
CO_2 (% volume)	18	20	16	40	37	1
H_2O (% volume)	Residual	Residual	10	Residual	Residual	–
CH_4 (% volume)	10	12	11.4	45	63	81
C_{2+} (% volume)	Included in CH_4	Included in CH_4	Included in CH_4	0	0	4
H_2S (ppm)	22	25	48	<100	<1000	–
O_2 (% volume)	–	–	–	1	0	–
NH_3 (ppm)	128	324	–	5	<100	–
N_2 (% volume)	3	4	46	15	0.2	14
H_2/CO Ratio	1.8	1.7	0.98	–	–	–
Tars, ash (g/Nm^3)	3	36	130	Residual	Residual	–
NCV (MJ/Nm^3)	13	12	7.4	16	23	31.6
NCV (MJ/kg)	16	14	5.5	12	20	38

Table 4

CRS and biomass hybrid power plants performance and cost.

Plant designation	CAPEX (millions of euro)	Hybrid fuel consumption (ton/year)	Generated electricity (GWh/year)[a]	Solar fraction	Feedstock to electricity efficiency (net)	LCOE[b] (€/kWh)
FRB#CRS#3	33	24×10^3	31.7	34%	16%	0.16
PG#CRS#1	36	18×10^3	32.6	37%	17%	0.25
PG#CRS#2	46	14×10^3	32.2	50%	14%	0.27
PG#CRS#3	37	18×10^3	32.4	39%	17%	0.26
WG#CRS#1	36	20×10^3	32.6	37%	17%	0.17
WG#CRS#2	46	16×10^3	32.2	50%	14%	0.20
WG#CRS#3	37	19×10^3	32.4	39%	17%	0.17
RDF#CRS#1	36	23×10^3	32.4	35%	15%	0.18
RDF#CRS#2	46	19×10^3	32.2	48%	13%	0.22
RDF#CRS#3	37	23×10^3	32.2	37%	15%	0.19
BD#CRS#1	37	14×10^3	32.5	37%	18%	0.15
BD#CRS#2	47	11×10^3	32.2	50%	15%	0.19
BD#CRS#3	38	14×10^3	32.4	39%	18%	0.15
BL#CRS#1	28	23×10^3	32.6	37%	18%	0.16
BL#CRS#2	38	18×10^3	32.2	50%	15%	0.19
BL#CRS#3	29	23×10^3	32.4	39%	18%	0.16
NG#CRS#1	24	7.4×10^3	32.6	37%	18%	0.15
NG#CRS#2	35	5.9×10^3	32.3	50%	15%	0.18
NG#CRS#3	26	7.2×10^3	32.4	39%	18%	0.16

[a] 90% plant availability.

[b] For a 30 year life time, annual 8% dept interest rate and 1% annual insurance costs [15].

Table 5
Economical analysis for base cases.

Plant designation	Majority resource	Feed-in tariff (€/kWh)	IRR (%)[b]	NPV (million euro)		Payback period (years)	
				With taxes and inflation[c]	Without taxes or inflation	With taxes and inflation[c]	Without taxes or inflation
CRS#1	CSP	0.273	9.9	7.9	30	14	10
CRS#2	CSP	0.273	9.2	11	42	16	11
CRS#3	CSP	0.273	10	8.6	32	14	10
FRB	Forest biomass	0.109	4.5	0.5	9.4	27	20
PG	Wood Pellets	0.109	N/A	−84	N/A	N/A	N/A
WG	Wood residues	0.109	N/A	−7.2	N/A	N/A	N/A
RDF	MSW RDF	0.074	N/A	−31	N/A	N/A	N/A
BD	Wastewater sludge	0.117	18	14	41	6	4
BL	MSW	0.104	N/A	−2.1	N/A	N/A	N/A
NG	Natural gas	0.05[a]	N/A	−43	N/A	N/A	N/A

[a] MIBEL market price, average estimation.
[b] Considering national taxes from 2012 but without inflation.
[c] Considering an average 4% annual inflation and national taxes from 2012.

Table 6

Economical analysis for hybrid options.

Plant designation	Majority resource	Feed-in tariff (€/kWh)	IRR (%)[c]	NPV (million euro)		Payback period (years)	
				With taxes and inflation[d]	Without taxes or inflation	With taxes and inflation[d]	Without taxes or inflation
FRB#CRS#3	Forest biomass	0.152[a]	4.4	0.8	21	28	20
WG#CRS#1	Wood residues	0.170[b]	5.5	3.3	27	24	18
WG#CRS#2	CSP	0.191[b]	3.4	−1.8	23	N/A	21
WG#CRS#3	Wood residues	0.173[b]	5.2	2.8	27	25	18
BD#CRS#1	Wastewater sludge	0.175[b]	11	15	53	13	9
BD#CRS#2	CSP	0.195[b]	6.4	6.9	42	22	16
BD#CRS#3	Wastewater sludge	0.178[b]	10	14	51	14	10
BL#CRS#1	MSW	0.167[b]	7.4	5.3	25	20	14
BL#CRS#2	CSP	0.189[b]	3.9	0	21	30	20
BL#CRS#3	MSW	0.170[b]	6.9	4.7	25	21	15

[a] Calculated by national renewable electricity generation tariff formula, considering the solar and biomass boilers power.
[b] Calculated from base cases tariff using an weighted average from the energy generated from CSP and biomass.
[c] Considering national taxes from 2012 but without inflation.
[d] Considering an average 4% annual inflation and national taxes from 2012.