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A techno-economic comparison between two design configurations for a small scale, biomass-to-energy gasification based system

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ABSTRACT

Biomass has great potential as a clean and renewable feedstock for producing modern energy carriers. This paper focuses on the process of biomass gasification, wherein the synthesis gas is subsequently used to produce electricity. A comparison between the most promising design configurations for the industrial application of gasification based, biomass-to-energy cogenerators in the 100–600 kWe range is presented. Mass and energy balances and material and substance flow analyses drawn for each design solutions are based on the experimental data obtained from a pilot scale bubbling fluidized bed air gasifier, having a feeding capacity of 100 kg/h and operated with a commercially available, natural biomass. Measurements taken during the experimental tests include the syngas complete composition as well as the characterization of the bed material, the entrained fines collected at the cyclone and the purge material from the scrubber. The techno-economic performances of two energy generation devices, a gas engine and an externally-fired gas turbine, have been estimated on the basis of the manufacturer's specifications. The study concludes that the internal combustion engine layout is the solution that currently offers the higher reliability and provides the higher internal rate of return for the investigated range of electrical energy production.

1. Introduction and framework

Biomass is the oldest known source of energy and it is a renewable energy. The possible utilization of the biomass energy content gained a great interest in the last decade, because of its potential to displace a large part of conventional fossil fuel for electricity production. The main reasons lay in the large availability of biomass resources, the progressive depletion of conventional fossil fuels and the potential better air pollution control of the related power generation processes [1–3]. A large amount of energy is in fact potentially available from biomass, since sources that can be used for energy production cover a wide range of materials (wood and wood waste, agricultural crops and their waste by-products, organic fraction of municipal solid waste, residues from agro-industrial and food processes, aquatic plants such as algae and waterweeds). Moreover, the limitate sulphur and greenhouse gas emissions associated with the use of biomass for energy production could respond to the growing pressure for the achievement of a better environmental sustainability of power generation processes.

Despite the widely agreed potential of bioenergy utilization, key problems regarding the use of biomass remain the unsteady availability, related to biomass seasonality and geographical distribution over the territory that often make the logistics (collection, transport and storage operations) complex and expensive [2], as well as the necessity of an energy production which should be not only environmental sustainable but also economic competitive. In other words, biomass has great potential as a renewable and relatively clean feedstock for producing energy carriers, such as electricity and transportation fuels, but in order to compete with fossil energy sources it needs to utilize efficient conversion technologies [4,5].

Biomass can be converted to a wide variety of energy forms (electricity, process heat for industrial facilities, domestic heating, vehicle fuels) by means of a number of thermochemical and biochemical processes [3]. With reference to low-value lignocellulosic biomass, biological conversion processes still faces challenges in low economy and efficiency, even though fermentation and anaerobic digestion are today commercially proven technologies, suitably used to produce ethanol from biomass containing sugar [6–8] and biogas from high-moisture content biomass, such as the organic fraction of MSW [9].

Combustion, pyrolysis and gasification are the three main thermochemical process solutions. Combustion is traditionally used to convert biomass energy into heat and power in the process indus-

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try: the net conversion efficiency is generally low, even if higher values may be obtained in co-combustion in coal-fired power plants [2]. Pyrolysis is the thermal degradation of biomass in a bio-oil, a solid fraction and a high-heating value gas: a wide application is still restricted by difficulties in the efficient processing of bio-oil [3]. Gasification converts biomass in a combustible gas mixture (called producer gas or syngas), mainly made of carbon monoxide, hydrogen and lower content of methane and able to provide a wide range of products, extending from clean fuel gas and electricity to bulk chemicals [10,11].

Different gasification technologies are available today and fluidization is the most promising among all of them, for a series of reasons, among which the possibility to use different fluidizing agents, reactor temperatures and gas residence times, to inject reagents along the reactor height and to operate with or without a specific catalyst [12,13]. The key to achieving economically and environmentally efficient energy recovery from natural and waste biomass gasification is to overcome the problems associated with the formation and release of different contaminants (mainly tars, i.e. high molecular weight hydrocarbons that condensate at ambient temperature, but also heavy metals, halogens and alkaline compounds) that have an environmental and operating negative impact. The syngas cleaning approaches can be classified in treatments inside the gasifier (primary methods), such as adequate selection of main operating parameters, use of a proper bed additive or catalyst, specific gasifier design modifications, and hot gas treatments downstream of the gasifier (secondary methods), such as thermal or catalytic tar cracking and mechanical methods (ceramic, fabric or electrostatic filters, cyclones and wet scrubbers) [14,10,13]. The type and the possible combination of primary and secondary methods are strongly dependent on the nature of biomass fuel and gasification technology as well as on the level of syngas cleaning required by the specific end-use device.

The aim of this study is to evaluate and compare the technical and economic performance of the most promising design configurations for the small scale industrial application of gasification-based biomass-to-energy cogenerators. To this end, a number of tests with a selected natural biomass was carried out in a pilot scale bubbling fluidized bed gasifier (BFBG). The collected experimental data were processed by different analytical tools such as mass and energy balances and material and substance flow analyses, in order to obtain information useful to define design solutions and configurations suitable for different electricity generation devices. The energy conversion devices for the range of electric output of interest, among all those commercially available, are then analyzed and selected. The technical and economic performances of the best two plant configurations are finally described in details and compared.

2. The pilot scale fluidized bed gasifier

The utilized pilot scale bubbling fluidized bed gasifier has the characteristics schematically listed in Table 1. An olivine – a magnesium-iron silicate, $(Mg,Fe_2)SiO_4$ – was selected as material for the fluidized bed on the basis of results of previous investigations carried out on the same pilot-scale BFBG [15] and those reported on the scientific literature [16,17]. All indicated olivine as an interesting candidate to act as a bed catalyst for the tar cracking reactions in biomass gasification, even taking into account its low cost and excellent resistance to attrition in the fluidized bed reactor. The main characteristics of the utilized olivine are reported in Table 2.

In the reported experiments, air was used as reducing agent and always injected at the bed bottom while the fuel was always fed by means of an over-bed feeding system. The fluidizing air stream was heated up to 545 °C by a couple of electric heaters before entering the reactor. The fuel and blast flow rates were mutually adjusted so that, at the fixed fluidizing velocity, the desired equivalence ratio ER was obtained (where ER is defined as the ratio between the oxygen content of air supply and that required for the stoichiometric complete combustion of the fuel effectively fed to the reactor). The cylindrical BFB reactor was heated up to the reaction temperature by the sensible heat of pre-heated blast gases and by a set of three external electrical furnaces. The gas generated in the reactor was sent to the syngas conditioning section composed of a high efficiency cyclone and a wet scrubber (for the removal of tars, residual fly ashes and acid gases) and finally incinerated by a safety flare. An accurate description of the plant and of experimental procedures is provided elsewhere [13,18]. Here it is sufficient to highlight that gas composition, upstream and downstream of the syngas conditioning section, was on-line measured by IR analyzers for the main syngas components (carbon monoxide and dioxide, hydrogen, methane) and by two micro-gas-chromatographs equipped with different columns for the detection of lighter and heavier hydrocarbons as well as of carbon monoxide and dioxide, hydrogen, nitrogen and water. Two different methods of tar evaluation were used: the first conservatively imputes to the tar amount the whole carbon loading which, as a result of a mass balance on atomic species, cannot be attributed either to the produced gas or to the solids collected at the cyclone or present inside the bed; the second method utilizes samples taken at the reactor exit, for about 30 min, by means of four in-series cold traps, and then sent to a gas chromatograph coupled with a mass spectrometer. Data obtained from on-line and off-line gas measurements and those from chemical analyses of solid samples were processed to develop complete mass balances on atomic species and the related energy balance for each run. The flow rate of produced syngas was determined by the “tie component” method

Table 1
Main design and operating features of the utilized pilot scale bubbling fluidized bed gasifier.

Geometrical parameters	ID: 0.381 m; total height: 5.90 m; reactive zone height: 4.64 m; wall thickness:12.7 mm
Feedstock capacity	100 kg/h
Thermal output	Up to about 500 kW
Typical bed amount	145 kg
Feeding system	Over-bed air-cooled screw feeder
Gasifying agents	Air, oxygen, steam, carbon dioxide
Range of bed temperatures	700–950 °C
Range of fluidizing velocities	0.3–1 m/s
Flue gas treatments	Cyclone, scrubber, flare
Safety equipments	Water seal, safety valves, rupture disks, alarms, nitrogen line for safety inerting

Table 2
Characteristics of the olivine particles utilized as bed material in the pilot scale bubbling fluidized bed gasifier.

Mineral	Mg-Fe silicate
Chemical composition, %	
SiO_2	39–42
MgO	48–50
Fe_2O_3	8–10.5
CaO	<0.4
K_2O	–
TiO_2	–
Al_2O_3, Cr_2O_3, Mg_3O_4	0.8
LOI (*loss of ignition*)	0.20
Size range, μm	200–400
Sauter mean diameter, μm	298
Particle density, kg/m^3	2900
Minimum fluidization velocity (at 850 °C), m/s	0.030
Terminal velocity (at 850 °C), m/s	2.0

Table 3
Chemical characterization of the reference biomass.

Ultimate analysis, % on weight basis	
C (min–max)	45.9 (45.7–46.1)
H (min–max)	5.63 (5.60–5.66)
N (min–max)	0.33 (0.30–0.36)
S (min–max)	0.01
Moisture (min–max)	7 (6.9–7.1)
Ash (min–max)	1.3 (1.2–1.4)
O (by difference)	39.83
C:O ratio	1.15
Proximate analysis, % on weight basis	
Moisture (min–max)	7.0 (6.9–7.1)
Volatile matter (min–max)	72.0 (70–74)
Fixed carbon (min–max)	19.7 (19–20)
Ash (min–max)	1.3 (1.2–1.4)
Chemical analysis, g/100 g	
Cellulose[a]	45.1
Hemicelluloses[b]	19.6
Lignin[c]	22.3
Heating value (by the relationship of Sheng and Azevedo [27])	
HHV, kJ/kg	18,600
LHV, kJ/kg	15,900

[a] As obtained by the value of acid detergent fiber (ADF) less that of acid detergent lignin (ADL).
[b] As obtained by the value of neutral detergent fiber (NDF) less that of acid detergent fiber (ADF).
[c] As obtained by the value of acid detergent lignin (ADL).

Table 4
Operating conditions and performance parameters of the pilot scale gasifier under two values of equivalence ratio.

Operating conditions		
ER (equivalence ratio)	0.23	0.28
AF (air/fuel ratio), kg_{air}/kg_{fuel}	1.26	1.53
Temperature of fluidizing air at gasifier entrance, °C	545	545
Output process data		
Temperature of fluidized bed at thermal steady-state, °C	810	880
Temperature of syngas at gasifier exit, °C	680	740
Q_{syngas}, $m^3{}_N/kg_{fuel}$	1.8	2.1
LHV_{syngas}, $kJ/m^3{}_N$	6800	5900
Specific energy, kWh/kg_{fuel}	3.4	3.4
CGE (cold gas efficiency)	0.77	0.77
Composition of syngas (downstream of cyclone and scrubber), %		
N_2	47.6	50.7
CO_2	16.0	14.0
CO	16.9	17.9
H_2	12.5	12.3
CH_4	5.0	3.9
C_2H_4	1.2	0.8
C_2H_6	0.17	0.04
C_2H_2	0.08	0.08
C_3H_6	0.06	0
C_6H_6	0.26	0.25
C_7H_8	0.10	0.02
C_8H_{10}	0.05	0.01
Syngas contaminants (upstream of cyclone and scrubber)		
Entrained fines, g/kg_{fuel}	26.2	20.9
Entrained carbon fines, $g_C/kg_{C\text{-}fuel}$	43.3	31.2
PAH, $mg/m^3{}_N$	450	2300
HCl, $mg/m^3{}_N$	17	13
H_2S, $mg/m^3{}_N$	0.7	1
NH_3, $mg/m^3{}_N$	14	16

[19] applied to the value of nitrogen content in the dry syngas, as obtained by (on-line and off-line) GC measurements.

3. The configurations of the biomass-to-energy system

The configurations of the gasification based, biomass-to-energy system investigated in this study were defined on the basis of the following design specifications. The plant is designed to be fed with a natural biomass: a commercially available beechwood for domestic heating, having the chemical characteristics reported in Table 3. The process is designed to produce electricity, even though additional thermal energy is available to use in case a demand is present at the installation site. The electrical size range of interest is that of small scale plants, between 100 and 600 kWe. These input data, together with the evidence that fluidized reactors allow a continuous operation, a sufficient flexibility on biomass feedstock and a limited tar content in the syngas [10,11] lead to individuate the atmospheric bubbling fluidized bed air gasification as the conversion process to be adopted.

The design configurations for the industrial application of gasification plants in the range of interest can be sketched as a combination of three sections: syngas production, syngas utilization and syngas or flue gas cleaning. The first defines the syngas that can be produced and then, for fixed biomass fuel and gasification technology, the quantity and quality of this syngas. The utilization section indicates the producer gas that can be utilized in a specific energy conversion device and then, for a given machinery (steam turbine, gas engine, internally or externally-fired gas turbine), its temperature, heating value and cleaning level (i.e. tar and dust content but also that of alkaly and inorganic contaminants). The relative succession of the utilization and cleaning sections depends on the two possible types of biomass-to-energy gasification system that can be adopted: the “power gasification”, where the producer gas is first cleaned then burned, and the “heat gasification”, where the producer gas is first burned then cleaned [11]. Then, for a “power gasifier” the cleaning section must function as an interface between the characteristics of the producer gas and those required by the specific generator set, even though the conditioning of the gas up to the specifications imposed by the generator set is not always economically viable [14,20]. Instead, for a “heat gasifier”, it consists of a possible pre-treatment of the syngas to remove contaminants (such as hydrogen chloride) before it goes into the combustor and, above all, of an air-pollution control (APC) system for flue gas cleaning.

The following paragraph investigates the syngas characteristics that can be obtained by a BFBG fired with the design biomass fuel, mainly on the basis of the experimental activity carried out with the described pilot scale gasifier. The energy conversion devices for the range of electric output of interest, among all those commercially available, are then described and selected. The cleaning sections that complete the two most promising plant configurations are finally defined.

3.1. The gasification section

The gasification section has been designed on the basis of an experimental activity carried out on the pilot scale BFBG operated under autothermal conditions, i.e. with the only external heat addition being provided for the pre-heating of the reducing and fluidizing air stream. The reactor was operated with the natural biomass, in a bed of olivine particles fluidized at a velocity of 0.6 m/s, a bed temperature of about 850 °C, an air preheating temperature of 545 °C and with an equivalence ratio ER between 0.2 and 0.3. The performances of the BFBG were measured and recorded only when the chemical composition of the produced syngas and the temperature profile along the reactor reached stedy-state conditions. The obtained results, reported in Table 4 for two values of ER, have been combined with a recently defined environmental assessment tool, the Material Flow Analysis, which is named Substance Flow Analysis when it is referred to a specific chemical species. MFA/SFA is a systematic assessment of the flows and stocks of materials and elements within a system defined in space and time. It connects the sources, the pathways, and the intermediate

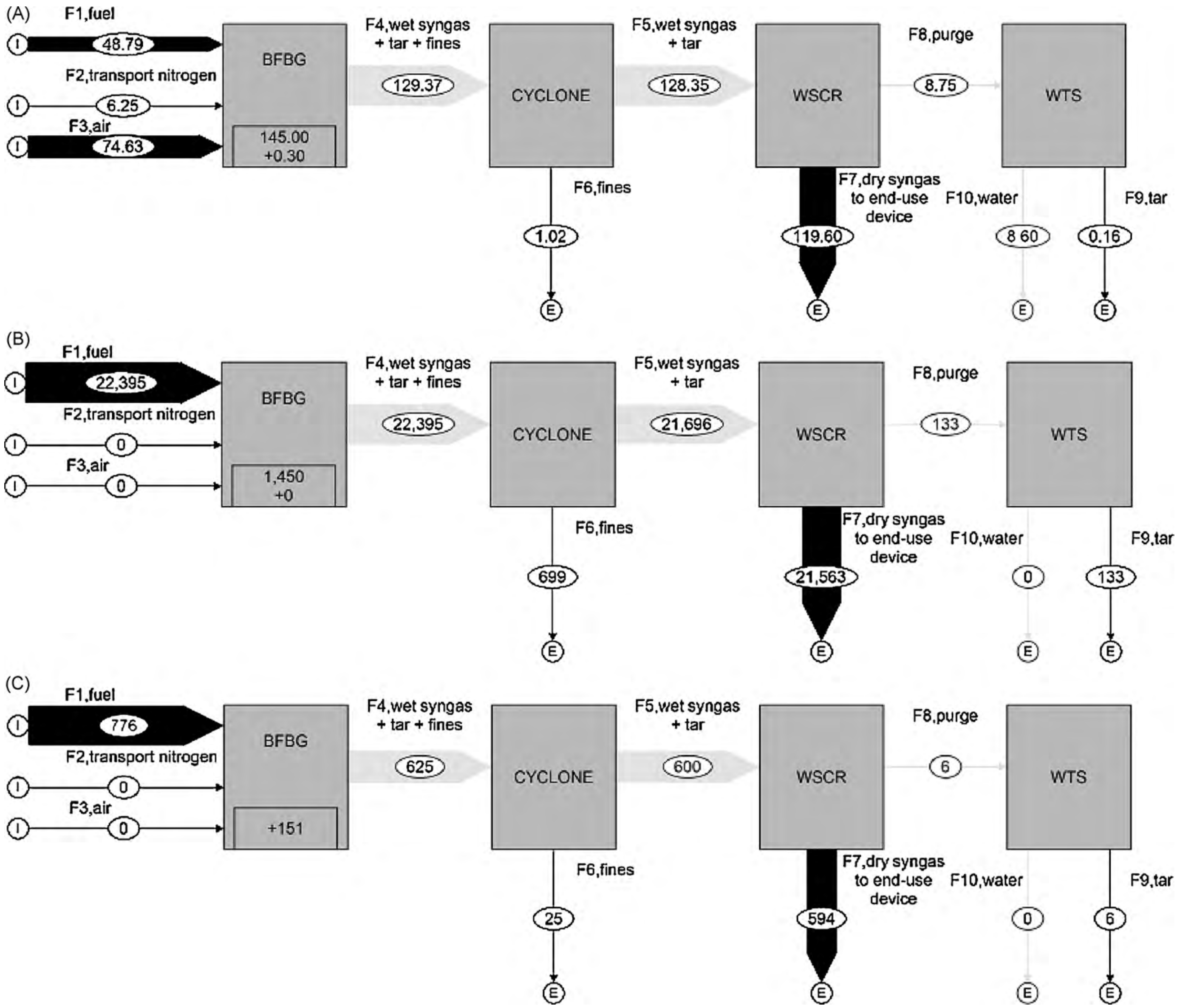

Fig. 1. Layers of mass and energy balances throughout the pilot scale gasifier in its present configuration: (A) total mass (kg/h); (B) carbon element (g/h); (C) feedstock energy (MJ/h).

and final sinks of each species in a specific process [21]. These characteristics make MFA/SFA attractive as a decision support tool, as showed by its utilization in process evaluation of waste treatments and recycling options [22] and in waste management planning [23]. In this study MFA/SFA was used to deeper understand the performance of the pilot scale gasifier and to define and quantitatively assess some design solutions and operating criteria of the biomass gasification system.

The quantified flow diagrams reported in Fig. 1 are the result of the MFA/SFA applied to the main process units (gasifier, cyclone, wet scrubber, water treatment system) of the pilot scale gasification system, when operated at an equivalence ratio of 0.28. Each flow in entrance to or in exit from a specific unit is identified by means of a black arrow if the specific data have been measured or fixed, or by a grey arrow if the data have been obtained by means of MFA/SFA. The layer of total mass flow rate is reported in Fig. 1A. The input flows to the BFBG unit are the stream of biomass fuel, that of a small flow rate of nitrogen utilized to facilitate the fuel injection and that of air used as reducing agent and fluidizing gas. The output flow stream is the obtained syngas, which still contains heavy hydrocarbons, inorganic pollutants and entrained fines. The dirty syngas is sent to the cyclone for dust abatement and then to the wet scrubber for removal of tars and inorganic compounds. The specific production of syngas is equal to 2.45 kg_{syngas}/kg_{fuel} (i.e. 2.1 $m^3{}_{N,syngas}/kg_{fuel}$) while that of elutriated fines is 20.9 g_{fines}/kg_{fuel}. The stock of 145 kg of bed particles is progressively incremented (0.30 kg/h) as a result of opposite effects of elutriation losses and fuel ash accumulation. The experimental activity provides the complete chemical composition of streams leaving the cyclone and the water treatment system. These data have been used for the substance flow analysis of carbon, iron, magnesium and other elements and for the feedstock energy flow analysis, as made in a similar study [24].

Fig. 1B reports the result of the mass balance applied to the carbon element, i.e. the carbon layer of SFA. It gives the carbon conversion efficiency CCE, defined as the ratio between the mass flow rate of the carbon present in the syngas as CO, CO_2, CH_4 and light hydrocarbons (until C_5H_m) and the mass flow rate of the carbon that enters the reactor with the fuel. The value of 0.96 of CCE is evaluated as the ratio between the mass flow rates of the syngas carbon stream, F7, and fuel carbon stream, F1. CCE is mostly affected by the carbon losses related to the fly ash stream, F6 (for 3.1%) and, for an almost negligible fraction (0.6%), to those of purge stream, F8. The carbon layer finally reports an important state variable of the biomass gasification process, the bed carbon loading W_C, which is the amount of carbon present in the bed as char particles at the steady-state condition [25]. Its value of 1.45 kg is a function of bed temperature and equivalence ratio. Fig. 1C reports the layer of feedstock energy, i.e. the heat of combustion of each input and output streams [26]. The energy flow entering with the biomass fuel has been determined by means of a relationship recently proposed and validated specifically for biomass fuels [27], while the energy flows of exit streams have been evaluated on the basis of the heats of combustion of the specific substances. The resulting difference in feedstock energy, 151 MJ/h, is that "invested" at the steady-state condition to convert the solid biomass in a gaseous fuel. Reported data allow to evaluate the cold gas efficiency CGE, defined as the ratio between the chemical energy of obtained syngas and that of injected fuel: the value of 0.765 is mainly determined by the chemical energy utilized inside the gasifier (19.5%) and, for a smaller part, by the fraction of feedstock energy lost with the entrained fines (3.2%) and with the heavy hydrocarbons of the purge stream from the water treatment system (0.8%).

These results suggest two possible design solutions: the make-up of bed olivine particles and the recycle of entrained fines. In particular, the latter could lead to some advantages. The first is an increase of both CCE and CGE as a consequence of the additional residence time of carbon fines inside the reactor, by taking into account that the reactivity of these fines has been demonstrated to be sufficiently high by a parallel investigation carried out by means of a thermo-gravimetrical balance [24]. The consequent advantage is that there is no necessity for a further treatment or disposal of these fines. Another advantage of fly ash recycle is the reinjection inside the gasifier of large part of escaped inorganic fraction, which could limit the entity of olivine make-up. Fig. 2 reports the results of material and substance flow analyses in the gasifier design solution that includes the recycling of fines into the reactor and shows the increased values of syngas yield, carbon conversion efficiency and cold gas efficiency. These data were finally combined with relationships of fluidization engineering [28] in order to determine the

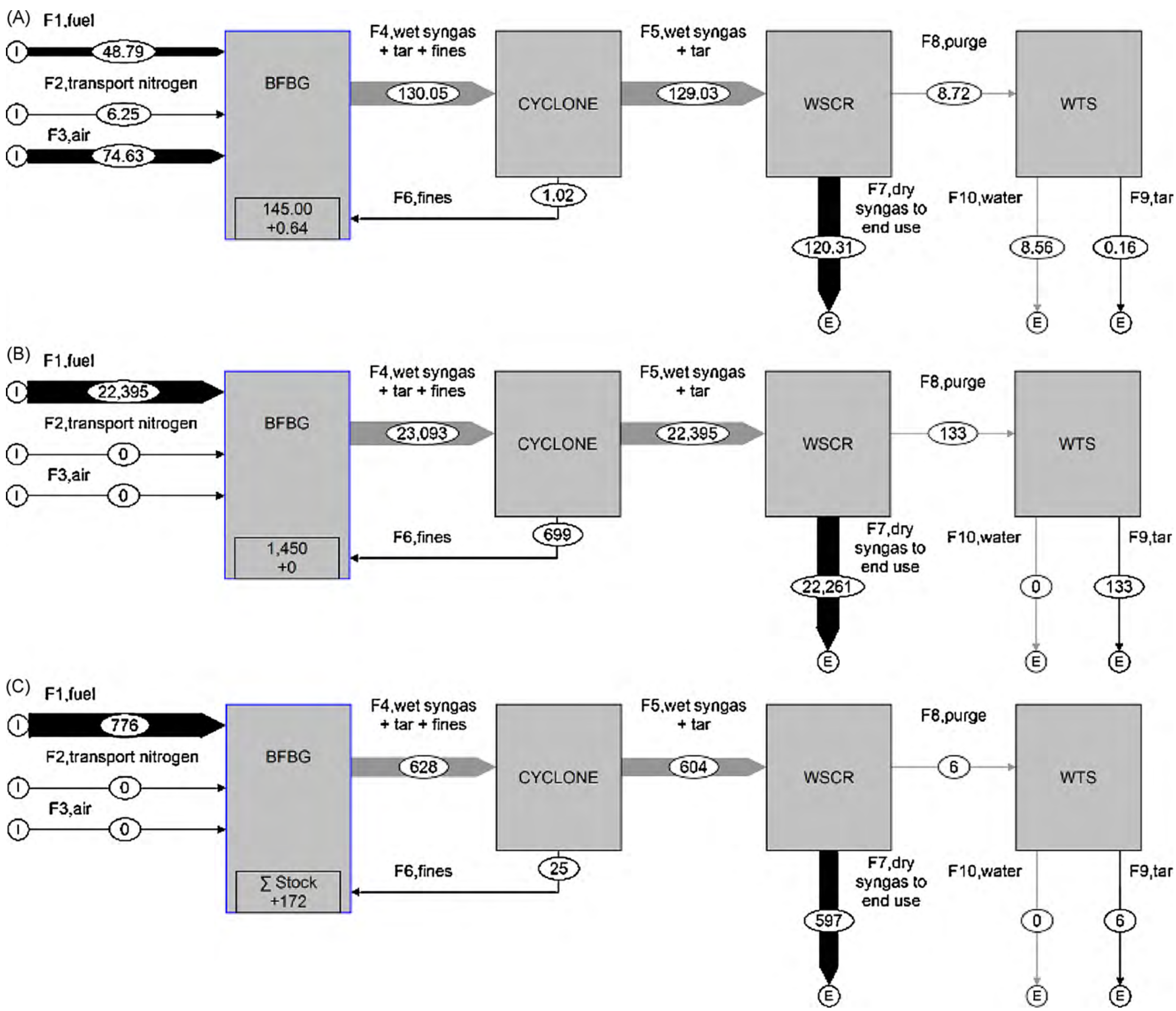

Fig. 2. Layers of mass and energy balances throughout the pilot scale gasifier in the configuration with the recycling of entrained fines: (A) total mass (kg/h); (B) carbon element (g/h); (C) feedstock energy (MJ/h).

Table 5
Advantages and disadvantages of different energy conversion devices for syngas from biomass gasification.

Energy conversion device	Net electrical efficiency of gasification plant	Main advantages	Main disadvantages
Steam turbine	10–20%	•Turbine components are isolated from combustion products •Long maintenance intervals, high availability •High specific work (kJ/kg yielded for working fluid)	•Expensive •Electrical efficiency is low at small sizes •Partial load decreases efficiency significantly •Plants is extremely large due to space requirements for the condenser and the boiler
Gas turbine	15–25%	•Electrical efficiency is good even at small sizes •Compact assembly •Long maintenance intervals, high availability •Ideal for cogeneration plants (CHP) due to high exhaust temperatures	•Turbine components are exposed to combustion products •Partial load decreases efficiency significantly •Moderately expensive
Externally fired gas turbine	10–20%	•Turbine components are isolated from combustion products •Electrical efficiency is acceptable even at small sizes •Long maintenance intervals, high availability •Ideal for cogeneration plants (CHP) due to high exhaust temperatures	•Expensive •Heat exchanger is exposed to high temperature, aggressive combustion gases •Partial load decreases efficiency
Gas engine	13–28%	•High electrical efficiency also at small sizes •Relatively inexpensive •Durable and reliable •Partial load effects efficiency only marginally	•Engine components are exposed to combustion products •Short and expensive maintenance intervals, low availability

main geometrical parameters of the gasification section. In particular, the reactor diameter was determined, for the fixed nominal plant capacity, on the basis of the cold gas efficiency and equivalence ratio, by keeping fixed the fluidizing velocity and the type and size of bed materials while the reactor height was determined by means of the Zenz and Weil relationship [29] in order to minimize the entrainment of fines from the bubbling bed gasifier.

3.2. The energy generation section

The list of possible devices that can be used to convert the syngas into electricity are schematically listed and compared in Table 5. Each of them has its advantages and disadvantages when coupled with a BFB gasifier.

The steam turbine and boiler combination has its main positive feature in insuring that the expanding fluid is completely isolated from the syngas combustion fumes, therefore avoiding the corrosion, fouling and plugging of the rotating parts. Moreover, due to the change of phase in the working fluid, the specific power of the machinery is extremely high. Commercially available steam turbines in the size range considered for this study, have an extremely low net electrical efficiency [10–20%] and additionally require a large condenser if the steam cycle is to be run in a closed loop configuration [30]. The intensive capital costs and the limited performance of the boiler and steam turbine configuration lead to the exclusion of this solution as a viable one [31].

Another combination that was not further analyzed is that with an internal combustion gas turbine. Although internal combustion gas turbines offer very good net electric efficiency across small size ranges, the direct combustion and expansion of the syngas and its fumes into the turbomachinery poses technical difficulties [31]. In fact, decontaminating the syngas of particulate, tar, alkali and acids to manufacturer's specification if often unfeasible due to incongruent costs of the equipment for the size range of the installation. Conversely, designing for costs can lead to residual contamination that fails to meet manufacturer's specifications which can cause unpredictable shortening of life or major failures of the machinery.

Recently a customization of the basic gas turbine machine has been readied for commercialization that overcomes the main problems associated with internal combustion gas turbines. This configuration is named either externally-fired gas turbine or hot-air gas turbine, since the working fluid is ambient air and the heat addition happens in a gas–gas high temperature exchanger [32]. The separation of the working fluid from the combustion fumes assures that the rotating parts are not deteriorated, fouled or plugged, as for a steam turbine, while the use of the exhaust clean hot air from the turbine outlet as the oxidizing gas in the syngas combustion, assures that high thermodynamic efficiencies are achieved.

The last solution that has been investigated is a syngas optimized high efficiency alternating engine. This type of engine is a proven technology that yields high electrical efficiency but has somewhat stringent requirements on both purity and technical conditions for the syngas supply [33,34]. In the case of the gas engine setup though, the decontamination of the syngas can be achieved with a sufficiently inexpensive equipment, an aspect that renders the solution viable and competitive. In fact, the engine based installation is usually regarded as the standard against which other alternatives have to be compared in terms of electrical and economical efficiency.

As mentioned above, the cleaning section must combine the characteristics of the produced syngas and those required by the specific generator set. On the basis of the preliminary selection process illustrated above, the cleaning section has been designed for the two most promising plant configurations: a "power gasifier" with a gas engine and a "heat gasifier" with an externally-fired gas turbine. The following paragraphs present a detailed analysis and the quantified process flow diagrams (PFDs) of these configurations, on the basis of the mass and energy balances developed for a plant feedstock capacity of 100 kg/h (i.e., about 750 t/y) of the selected biomass fuel, which corresponds to a net electric power output of about 100 kWe.

4. The gas engine configuration

The process flow diagram devised for the gas engine solution is reported in Fig. 3. The configuration is composed of three sections, the gasification, the cleaning and conditioning and the electricity generation sections. In the following paragraphs, the role and main characteristics of the single components of each section are schematically described. It is noteworthy that, while the gasification section has been modelled by using experimental data for the gasifier and ancillary equipments, the successive unit operations (i.e., preheating exchanger, dissipator, chiller, gas engine, exhaust

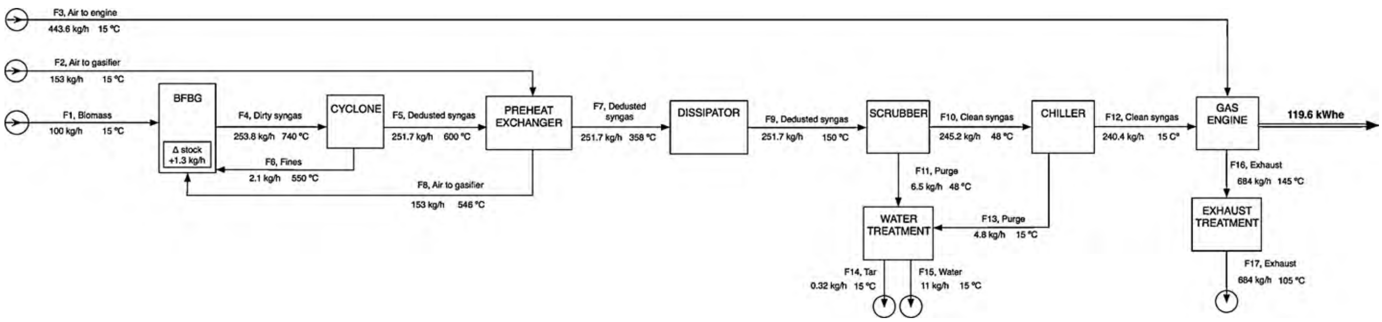

Fig. 3. Quantified process flow diagram for the gas engine configuration.

treatment) have been simulated on the basis of the performance data claimed by manufacturers and of standard mass and energy balances.

4.1. Gasification section

Bubbling fluidized bed reactor: the BFB reactor operates with a bed of olivine particles. *Cyclone*: this centrifugal collector, widely used for the separation and recovery of industrial dusts from process gases, is characterized by a high reliability and low capital and operating costs, due to the low pressure drop and the inexpensive maintenance schedule. The continuous operation mode of the cyclone allows for the devising of a recirculation circuit of the carbonaceous fines that can further increase the conversion efficiency of the fuel carbon and therefore increase the efficiency of the process.

4.2. Conditioning and cleaning section

Air preheating heat exchanger: it is a standard shell-and-tube exchanger that transfers the sensible heat from the hot syngas to the inlet gasification air so that the former is aptly cooled before being scrubbed and the latter is brought to the nominal temperature. The preheater is located downstream of the cyclone so as to reduce fouling and abrasion onto its hot side. *Dissipator*: it is an additional, inexpensive and low-maintenance heat exchanger required to bring the syngas temperature down to that compatible with the downstream scrubber inlet design point. *Scrubber*: it is the key component of the cleaning section, since it must guarantee the achievement of the final contaminants concentrations (residual dust, tar, acids and alkali compounds) required by the gas engine. Its cost is low but it necessitates a small water treatment unit or a connection to a water treatment plant. The component also separates small water particles that are entrained in the syngas stream to prevent their migration into downstream components. *Chiller and demister*: this component further cools the syngas below its dew point to reach the values of 25 °C and 60% of relative humidity, typically required by the engine inlet specification.

4.3. Electricity generation section

Gas engine: it is an internal combustion reciprocating piston engine, specifically optimized for syngas combustion rotating at 1500 rpm and directly coupled to an alternator. *Exhaust gas treatment section*: it is the engine exhaust stack, completed with a de-NOx catalytic system.

5. The externally-fired gas turbine design solution

The process flow diagram devised for the externally-fired gas turbine solution is reported in Fig. 4. The configuration is composed again of three sections, the gasification, the combustion and heat recovery with flue gas cleaning and the electricity generation sections. In the following, the role and main characteristics of the single components are schematically described. Also for this configuration, the gasification section has been modelled by using experimental data for the gasifier and ancillary equipments while the successive unit operations have been simulated on the basis of the performance data claimed by manufacturers and of standard mass and energy balances.

5.1. Gasification section

Bubbling fluidized bed reactor: it is the same type of BFB reactor adopted in the gas engine solution. *Cyclone*: this centrifugal collector too is identical to that of the gas engine solution and also in this case the recirculation of the fines is attainable.

5.2. Combustion and heat recovery section

Syngas combustor: it is a burner furnace where the syngas is combusted to yield hot flue gases to be sent to the high temperature gas exchanger. The placement of the combustor downstream of the cyclone avoids having to design a burner for particle laden gases which would make it more expensive and require higher maintenance. *Gasification air preheater*: it is a shell-and-tube heat exchanger that transfers heat from the flue gas stream from the

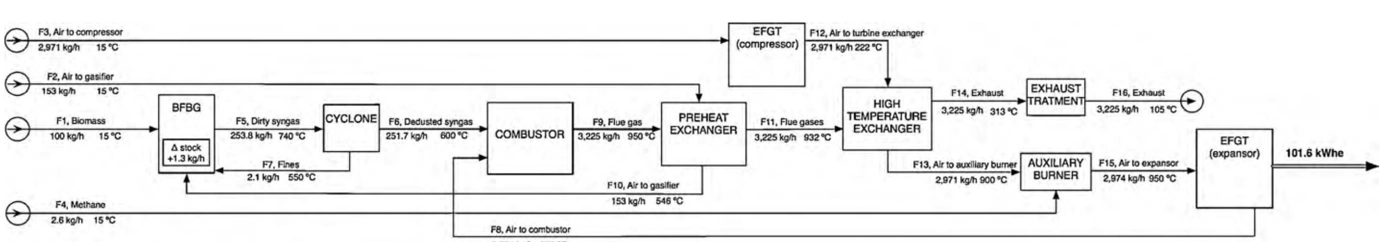

Fig. 4. Quantified process flow diagram for the externally-fired gas turbine configuration.

furnace to the inlet gasification air stream. This stage is also useful to lower the flue gases temperature in order to protect the flanged connection of the downstream high temperature heat exchanger. *High temperature heat exchanger* (*HTHE*): it is the crucial and key component of the proposed configuration [32]. It is a recuperative type heat exchanger that has the furnace hot flue gases on the hot side and the compressed air coming from the compressor stage of the turbine on the cold side. *Air pollution control*: it is the stack where flue gases from the furnace are sent before being released. It must be equipped with adequate devices for air pollution control, such as a de-NOx system.

5.3. Electricity generation section

Externally-fired gas turbine: it is a custom modified gas turbine where the combustion chamber has been replaced by an external exchanger for heat addition before the compressed ambient air expands into the turbine wheel. The addition of the high temperature exchanger replaces the traditional combustion chamber. *Auxiliary burner*: it is an in-line burner where a small flow rate of high LHV fuel (such as methane) is utilized to raise the air temperature up to the design setpoint of the turbine expander.

6. The costs and revenues extimation model

The economic model used in this study is based on the estimation of standard accounting items such as total plant costs, operating costs, taxation and direct revenues from the sale of the generated energy. All monetary values have been subject to time-value of money adjustment, i.e. future costs and revenues have been discounted to their present worth based on a fixed discount rate of 5% per year. This is needed to compare investment options that might generate costs and revenues in different time points along their expected life. Adopted models for total plant costs, operating costs and revenues [35] utilize manufacturer's information, average industry standard and the current incentive scheme available in Italy. Each item is detailed hereinafter.

6.1. Total plant costs

Total plant costs are the sum of equipment costs (i.e. the purchase cost of the equipment), direct costs (i.e. the costs associated with site preparation and assembly of components) and indirect costs (i.e. all costs associated with logistics and engineering). For each of the two configurations, equipment costs have been compiled on the basis of the manufacturer's quotes for the bill of materials associated with each layout and direct and indirect figures have been calculated by empirical factors applied to the cost of the equipment, based on a method first proposed by Lang [36,37]. For the size range under consideration, it was unpractical to base the estimation on available literature that has typically been accumulated for large to very large plants [38,39]; a comparison with existing installations that use equivalent technology is also difficult, because very few are operating in the investigated range. Equipment costs quotes have been gathered for a size in the middle of investigated range and then scaled to estimate the costs for the extremes of the size range. Direct and indirect costs have been calculated on the basis of the appropriate equipment costs, keeping the multiplying Lang factor constant across the range and equal to 1.5. Annual amortization of total plant costs has been calculated as a constant rate of 6.7% that corresponds to an expected plant life of 15 years. This value of the working life of the plant has been assumed on the basis of the following considerations: (i) the life of the energy generation device is the value that dictates the life of the whole plant, it being generally the most expensive piece of equipment; (ii) a proper maintenance program can reasonably extend the life of such devices to 15 years, as confirmed by manufacturers; (iii) it seems reasonable to assume a life non inferior to the available incentivized period. The scaling factor utilized for the equipment costs is based on a power law applied to estimates for the reference installation size obtained directly from manufacturers. An exponent of 0.6 was used, in accordance to basic literature [35,40] and recent works in the field [41].

6.2. Operating costs

The operating costs are the sum of the following items: maintenance, consumables and utility, waste streams disposal, labor and biomass cost. Maintenance costs (including running and extraordinary repairs) have been calculated as a percentage of equipment costs, with percentage values different for static equipment, the engine and the turbine. Consumables and utilities costs have been calculated for the reference installation size and then linearly scaled. Labor costs have been determined at the recurring wage for a single shift of a single worker (i.e. one man-year) because these plants are capable of operating unmanned. The disposal cost of the waste streams amounts to the product of the mass flow rate of waste by a fixed disposal fee of 120 €/t. The biomass fuel cost has been assumed to be equal to 20 €/t even though a range of variation 0–40 €/t has been then taken in consideration. All costs have been calculated in today's money and then discounted according to the year in which they occur.

6.3. Revenues

It has been conservatively assumed that revenues only come from the sale of the electrical energy produced. For this study, the Italian incentive scheme has been adopted as the basis for the energy compensation estimation. Then, an all-inclusive feed-in tariff of 0.28 €/kWhe delivered to the grid has been used even though a range of variation 0.21–0.35 €/kWhe has been then taken in consideration. The all-inclusive tariff encompasses compensation for the electrical energy sold and all the incentives associated with production of electricity from renewable resources and is valid for a period of 15 years. Access to the all-inclusive feed-in tariff, therefore excludes the attribution of renewable obligation certificates (green credits, or green certificates) or other incentives under current Italian legislation.

6.4. Taxes

Taxation has been set to 27.5% according to the current national fiscal imposition in Italy. No local taxation coefficient has been applied since no specific localization has been foreseen for the plant.

7. Technical and economical comparison

Although the two alternative plant configurations are based on identical gasification sections, they nonetheless differ in their energetic and environmental performance. Comparing the two plants on the basis on one aspect of their performance alone, e.g. their overall energy conversion efficiency, might be reductive since this would overlook other equally important aspects of the operation of power generation systems, such as their environmental burden, maintenance costs and ease of conduction. A broader comparison between the two biomass-to-energy configurations is traced in Table 6 while the economic comparison is visualized by Figs. 5 and 6. On one hand, the gas engine solution offers higher global efficiency (about 27%) due to the performance of the generator set and a lower capital cost (Fig. 5A), but has a generally lower availability (7680 h/y) and higher maintenance costs

Table 6
Synthesis of technical and economic performances for the two biomass-to-energy configurations, with reference to a nominal plant capacity of 200 kWe.

	Gas engine	Externally-fired gas turbine
Total energy conversion efficiency, %	27.1	23.0
Specific biomass conversion rate, $kWhe/kg_{fuel}$	1.20	1.02
Waste export, kg/kg_{fuel}	Gas: 6.64 Liquid: 0.11 Solid: –	Gas: 32.25 Liquid: – Solid[a]: 0.01
Exhaust gas temperature, °C	145	313
Total plant costs, €/kWe	6000	7600
Operating costs, (€/y)/kWe	940	690
Internal rate of return (IRR), %	13.2	13.0

[a] This value takes into account the sorbent utilized before the High Temperature Heat Exchanger but not the residues from APC unit.

(Fig. 5B). Moreover, it requires a suitable treatment unit for the waste water from the scrubber purge that is contaminated by tars, particulate and inorganics. On the other hand, the externally-fired gas turbine solution has a less efficient process (about 23%) due to the intrinsic thermodynamic limits and, for a less extent, to some losses inherent to the heat exchanger steps it embeds and has also a higher initial investment costs (Fig. 5A). The EFGT has a higher annual availability (7920 h/y), a lower maintenance costs and must dispose a solid waste stream (coming from APC unit) instead of a liquid one (coming from the wet scrubber unit), even though the advantage of the lack of an onerous water treatment system is balanced by the disadvantage of a very larger mass of flue gases to be treated at the stack (Figs. 3 and 4). Moreover, the EFGT configuration is more affected by the biomass cost due to the lower specific biomass conversion rate (Table 6), which results in larger fuel feed rates.

The different temperature and flow rate between the flue gas streams of the two alternative configurations are key elements in the evaluation of their cogenerative potential. The higher temperature and flow rate yielded by the EFGT configuration is apt to be used as a heat source for steam generation or bottoming Rankine cycle (Integrated Gasification Combined Cycle, IGCC), both valid ways to extract the residual available energy in the flue gases. On the other hand, the gas engine configuration has lower flow rates and lower temperatures, therefore it might not lend itself to be used viably as an energy source.

The graphs in Fig. 5A show that for all investigated sizes the GE solution has always total plant costs lower than the EFGT alternative and that both installations benefit of a power scale effect in the cost function. Anyway, a decrease in cost is expected for future EFGT installations due to economy attainable by the “*n*th plant effect” [39]: this aspect leaves a margin for the EFGT to become cost competitive with the GE in the near future. Fig. 5B illustrates the gap in the operating costs between the two alternatives that is mainly due to the different maintenance costs of the rotating equipment. Fig. 6A illustrates the influence of the GE’s operating burden on the generated cash flow: despite having a 17.8% higher annual electricity yield (as can be deduced from Table 6), GE’s cash flow is always lower than the EFGT one. Anyway, the EFGT’s lower operating costs cannot compensate for the higher capital costs and the graph in Fig. 6B shows how the internal rate of return (IRR) is always favourable to the GE alternative for nominal plant capacities equal or larger than 200 kWe. This is indicated even by the payback time values, which for the GE and EFGT configurations, respectively, result equal to 4 years and 5 years at a nominal plant capacity of 400 kWe and to 3 years and 4 years at a nominal plant capacity of 600 kWe. A closer examination of the graphs in Fig. 6B

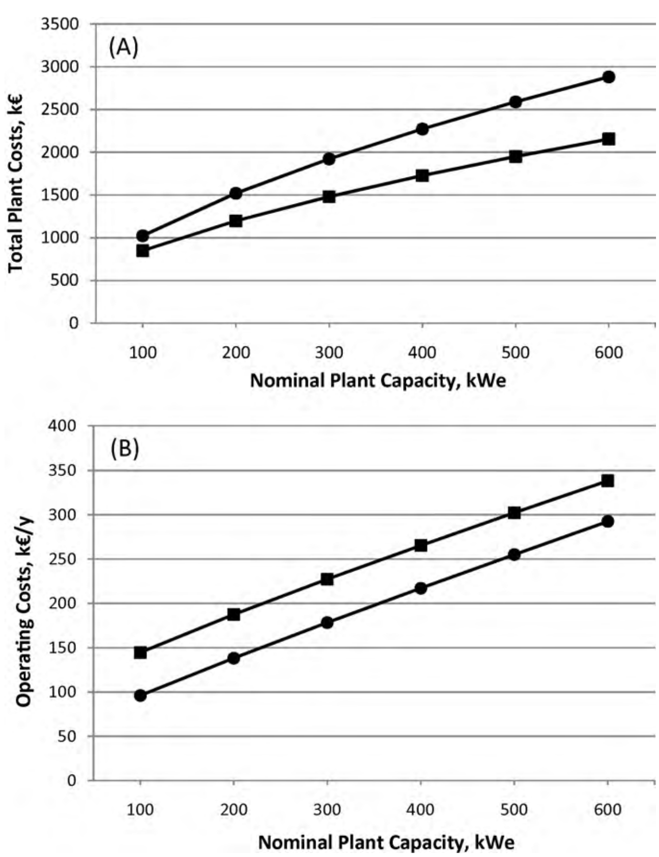

Fig. 5. Comparison of total and operating costs of the two biomass-to-energy design configurations, for a biomass fuel cost equal to 20 €/t. Squares: gas engine. Circles: externally-fired gas turbine.

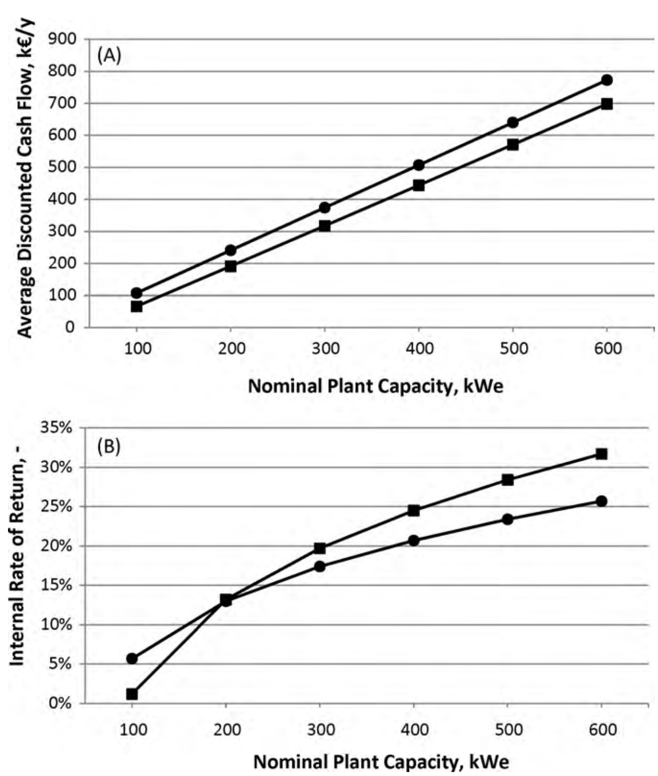

Fig. 6. Comparison of the financial performance indexes of the two biomass-to-energy configurations, for a biomass fuel cost equal to 20 €/t. Squares: gas engine. Circles: externally-fired gas turbine.

Table 7
Sensitivities of output variables to changes of individual input variables for the two biomass-to-energy configurations.

	Input variable	Base case	Variation	OC, k€/y	S_{OC}	ADCF, k€/y	S_{ADCF}	IRR, %	S_{IRR}
Gas engine			100	145		66		1.2	
	Nominal plant capacity, kWe	200		187	144	192	1.31	13.2	1.40
			300	227		318		19.7	
			0.74	189		191		13.1	
	CGE	0.77		187	−0.15	192	0.11	13.2	0.19
			0.80	186		193		13.3	
			0	162		209		15.0	
	Biomass cost, €/t	20		187	0.14	192	−0.09	13.2	−0.14
			40	213		174		11.3	
			0.21	187		118		4.6	
	Feed-in tariff, €/kWhe	0.28		187	–	192	1.53	13.2	2.41
			0.35	187		265		20.5	
Externally fired GT				97		107		5.6	
	Nominal plant capacity, kWe	200	100	138	0.58	241	1.11	13.0	0.92
			300	177		375		17.5	
			0.74	140		240		12.9	
	CGE	0.77		138	−0.24	241	0.11	13.0	0.20
			0.80	137		242		13.1	
			0	107		263		14.8	
	Biomass cost, €/t	20		138	0.22	241	−0.09	13.0	−0.14
			40	169		220		11.2	
			0.21	138		165		6.2	
	Feed-in tariff, €/kWhe	0.28		138	–	241	1.26	13.0	1.98
			0.35	138		317		19.1	

also shows how both plants become financially attractive only for a nominal plant capacity larger than 200 kWe.

The study was further pursued to determine sensitivities of relevant output variables to changes in plant capacity, operating and economic variables. To this end, the standard procedure for linearized sensitivity [35] has been used and applied at a "base case" assumed to be that of configurations reported in Figs. 3 and 4, for a nominal plant capacity of 200 kWe. Each input variable has been then changed in a fixed range of variation with respect to the base case. The sensitivity of generic output variable z was evaluated as:

$$S_z = \frac{(z^- - z^+)/z_b}{(v^- - v^+)/v_b}$$

where subscript b indicates the base case value. Superscripts − and + indicate, for the generic input variable v, the left and right extremes of assumed range of variation, whereas for the output variable z they indicate the values that it assumes for these extremes. The selected input variables were: the nominal plant capacity, whose range of variation has been assumed to be ±100 kWe with respect to the base case; the cold gas efficiency (CGE) that can be utilized as a state variable that synthesizes the gasifier performance: its range of variation has been determined on the basis of present and previous investigations [24] as well as of literature data [10,14]; the biomass fuel cost, whose range of variation has been determined on the basis of information from the European market [42]; and the incentive tariff, whose range of variation has been assumed to be ±25% of the Italian tariff. The output variables chosen to characterize the performance of the two proposed configurations were: the operating costs (OC), the average discounted cash flow (ADCF) and the internal rate of return (IRR). Values of input and output variables are reported in Table 7: an analysis of these data indicates the crucial role of the all-inclusive feed-in tariff on the main economical parameters (ADCF, IRR), with very high values of the sensitivity. This highlights that the absence of an adequate incentivization policy may undermine the economic sustainability of the biomass-to-energy plant, in particular for small size plants. These have worse economical performances, as visualized by curves in Fig. 6 and data in Table 7. The sensitivity related to the biomass cost appears less important, even though the expected large effect on the operating costs results in estimated values of the IRR that are remarkably different in the extremes of the assumed range of variation. As expected, the gasifier performance has a not relevant role in the assumed range of variation of cold gas efficiency, since the extremes of the interval (0.74 and 0.80) however represent very good reactor performances.

8. Concluding remarks

The industrial application of gasification based, biomass-to-energy cogenerators in the 100–600 kWe range has been investigated. The techno-economic performances of two promising design configurations, which implement a gas engine and an externally-fired gas turbine respectively, have been evaluated.

Mass and energy balances and material and substance flow analyses drawn for each design solutions were based on the experimental data obtained from a pilot scale bubbling fluidized bed air gasifier. The economic comparison has been carried out on the basis of the estimation of standard accounting items such as total plant costs, operating costs, taxation and direct revenues from the sale of the generated energy, all evaluated in the Italian context.

The results indicate that the internal combustion engine layout is the solution that currently offers the higher reliability and provides the higher internal rate of return for the investigated range of electrical energy production. Such conclusion does not take into account a cost decrease expected for future EFGT intallations due to economy attainable at the "nth installation", which leaves a margin for the EFGT to become cost competitive with the GE in the near future. Moreover, not one alternative is always preferable over the other: the choice has to account for site specific variables such as the presence of a heat demand and the costs of waste streams treatment and disposal.

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