Hybridization of solar power plants with biogas from anaerobic digestion: A modeled case study

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Simone Pedrazzi, Fabio Masetti, Giulio Allesina, et al.

Hybridization of solar power plants with biogas from anaerobic digestion: a modeled case study

Simone Pedrazzi[1,a)], Fabio Masetti[1], Giulio Allesina[1] and Paolo Tartarini[1]

[1] *University of Modena and Reggio Emilia, Department of Engineering Enzo Ferrari, Via Vivarelli 10, 41125 Modena, Italy.*

[a)] Corresponding author: simone.pedrazzi@unimore.it

Abstract. This work shows the numerical simulation of a hybrid renewable power plant composed of a Concentrated Solar Plant (CSP) with molten salt storage sub-system, a Rankine steam cycle power plant and a biomass anaerobic digester. Biogas produced by the digester is used as fuel in the boiler of the steam cycle coupled with methane. "Greenius" software has been used to simulate the CSP system aimed to satisfy an electrical power demand of the city Messaad, Algeria. Results concerning electrical energy produced, biogas and methane consumption was used with CAPEX and OPEX costs of the plant to calculate the Levelized Cost of the Electrical energy produced (LCoE). Several simulation were done varying the size of the solar field and of the thermal storage in order to find the compromise configuration with an high renewable energy production, a low methane consumption and a low LCOE. Simulations show that the CSP configuration with 2.07 of Solar Multiple (SM) and 9 of Full Load Hour (FLH) result in a low LCOE value (97.32 €/MWh), high annual system efficiency (11.51%), low methane share (8.73%) and low dumped heat ratio (10.22%).

INTRODUCTION

Nowadays the production of energy through the fossil fuel is still the best solution for having energy with a low cost on the market. Still, this brings to several issues related to the sustainability of the processes; this, combined with the growing lack of available fossil sources, must lead us in a next future in which the energy demanding of all countries must be satisfied by using only renewable energy sources [1].

But are these kinds of source both politically and economically feasible? Is the current technology developed enough to be competitive with the fossil energies on the market? The biggest drawback of the renewable energies is the availability of the renewable source itself: wind, sun and biomasses are strongly dependent from the environment and the weather where they are located in [2].

For instance, if we consider the concentrating solar power technology, in which basically the direct solar irradiation is concentrated on solar collectors, reflected on receivers to heat up a thermal conveyor fluid and used afterwards to drive a power block for production of electricity, its major drawback is the fact that it can mostly drive the power block only during sunlight hours; for the rest of the day the energy demand is usually covered by a thermal energy storage system and/or an auxiliary boiler, usually driven with fossil fuel [3].

Another common solution is using a hybrid system, that can combine the advantages of a renewable technology with a fossil one. This is usually the best solution against the hybridization of 2 renewable technologies due to the lower cost of a fossil technology that brings to a lower LCoE, the levelized cost of electricity produced by the whole system [4]. Moreover, although there are several projects ongoing and some experimental plants about fully renewable systems, a hybrid one with both fossil and renewable energy is still the best choice for efficiency [5].

This study aims to analyze a hybrid system between two renewable energies: a concentrating solar power plant supported by a boiler driven by biogas produced through the process of anaerobic digestion. The power plant is designed to fill the electrical demand of a small town, a small methane integration is allowed during the winter season when the solar energy is loo low to supply the electrical load.

The study is based on a larger project called REELCOOP (Renewable Electricity Cooperation), an EU/FP7 funded project aiming to develop renewable electricity generation technologies and promoting cooperation between

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EU Partner Countries and Mediterranean Partner Countries. The project started on the first of September 2013 and it has a duration of 4.5 years [6]. It concerned three projects with different renewable technologies in Turkey, Morocco and Tunisia, and, although the REELCOOP project has formally ended the 28th of February 2018, prototype tests are still ongoing [6].

The main goal of the study is to find the best configuration of the whole hybrid system for covering the energy demand of the town, giving priority of consuming the biomass available and filling the remaining gap through the CSP plant and the natural gas. Therefore, to make a cost-benefit assessment, capital expenditures (CAPEX) and operational expenditures (OPEX) were considered in order to calculate the levelized cost of electricity (LCoE) generated by hybrid plant.

MATERIAL AND METHODS

The plant of the following study has to be set for the city of Messaad, a small town in Algeria, about 360 km south of Algiers and with a population of around 120,000 inhabitants. The daily electrical power demand of the town has been displayed in the Figure 1.

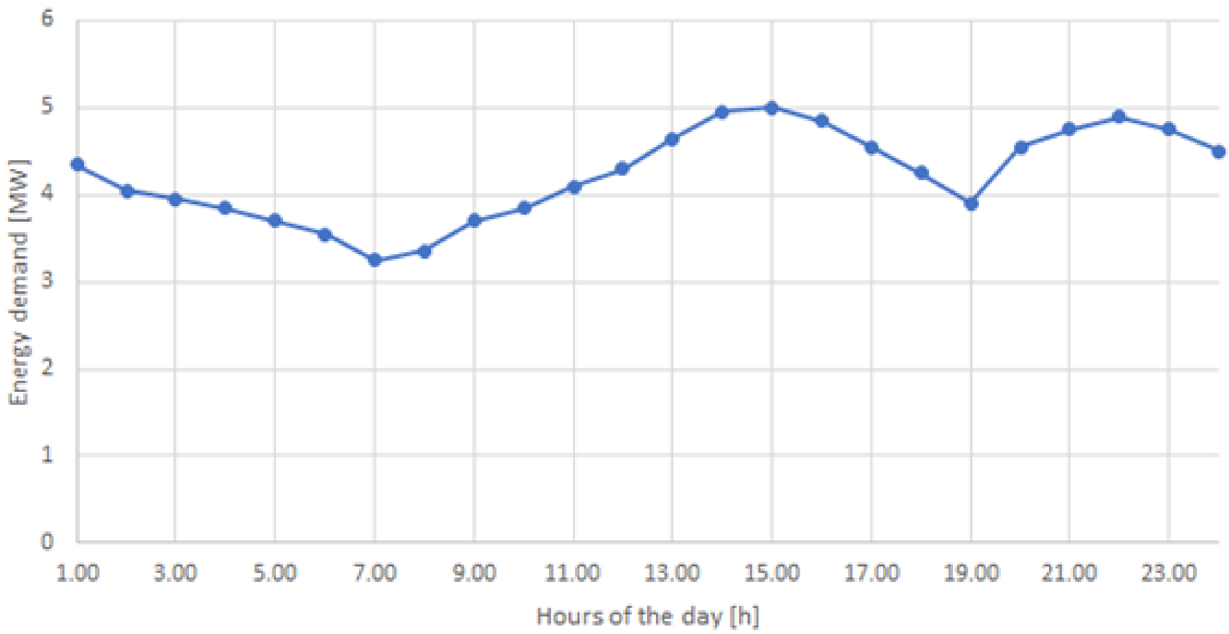

FIGURE 1. Electrical load curve

The maximum electric power demand of 5 MW is requested during the first hours of the afternoon. Afterwards, there is another peak at 22:00 and then the demand keeps decreasing until the 7:00 a.m. The demand must be satisfied by the plant for every day of the year. Moreover, according to the project, the city is able to provide a certain quantity of urban wastes that can be used for producing biogas through the process of anaerobic digestion. More precisely, it is available a daily biogas volume of $V_{biogas} = 68800\ m^3/day$ to fuel the boiler of the plant.

The system is depicted in Figure 2. Parobolic trough collectors (A) are used to heat the solar heat transfert fluid (Therminol VP-1) using solar energy. An heat exchanger (B) trasferts the heat from the solar fluid to the molten salts storage tanks (C,D). Several heat exchangers (E,F,G,H) are used to transfer the heat from the solar fluid to the working fluid of the Rankine cycle. A boiler (I) fuelled with biogas supplies heat to the cycle. If biogas and solar thermal power are not sufficient to run properly the cycle, methane is burned in the boiler to fill the gap. L and M are two turbines that move the alternator (N) needed for electricity production. In the heat exchanger O the working fluid condenses and then it is pumped again in the boiler using a pump. P is the evaporative tower used to cool down the water used for condensate the working fluid.

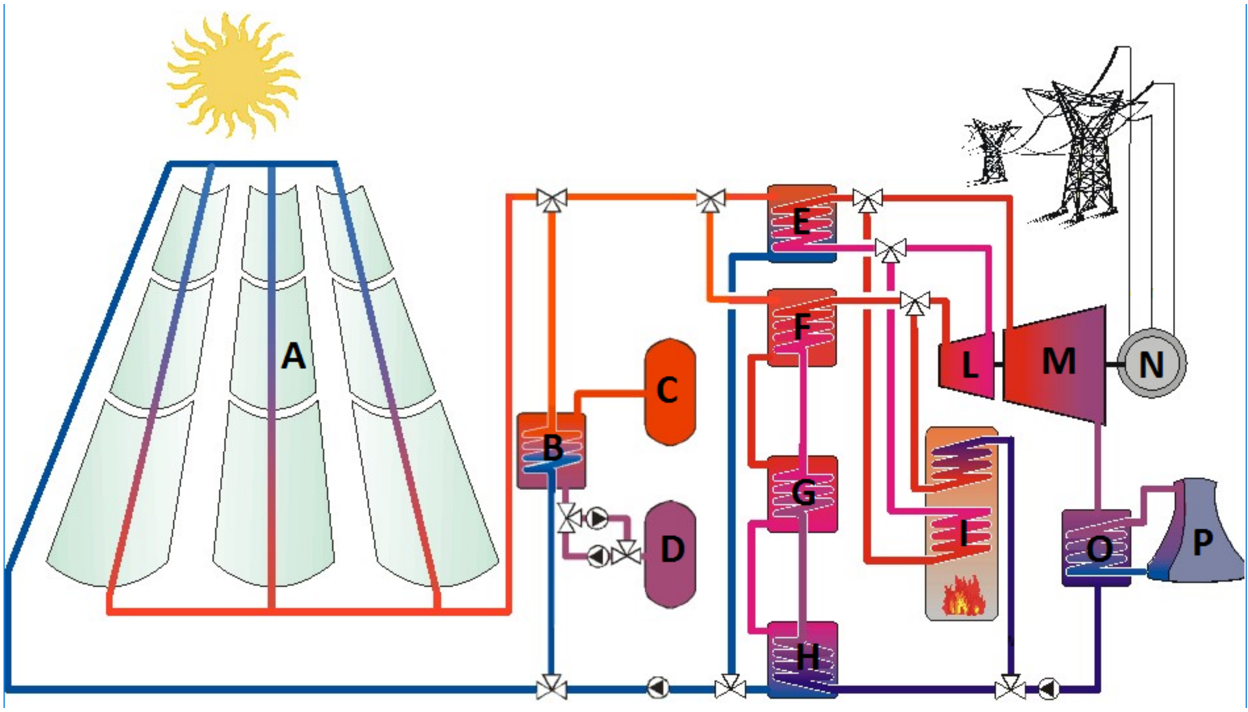

FIGURE 2. CSP system basic layout

For the simulation of the system, the "Greenius" software was used [7]. It is a free software developed by DLR Institute of Solar Research that can provide performance calculation algorithms with hourly resolution for concentrating solar power plant and other solar technologies. It can simulate both technical part, with a fast and reliable prediction of the electricity yield, and economic part of the plant, so it is possible to study the feasibility of the system [7].

Nevertheless, one of the major drawback of the software is that hybrid systems cannot be simulated; also, the boiler is considered only as an auxiliary part of the system, so the solar field has the priority in the production of energy to cover the energy demand. The aim of the project is instead to use as much biogas as possible to cover the demand, and then fill the gap of the total energy demand with the solar field.

To solve this issue, the solar field and the biogas-driven boiler outputs have been studied with the software separately. From the current quantity of biogas, a constant electrical power output of 3.1 MW is obtained. This value is calculated considering the composition biogas 50% of methane and 50% of CO_2 [8] and using Equation 1.

$$P_{biogas} = \frac{V_{biogas}}{3600 * 24} * \rho_{biogas} * LHV_{biogas} * \eta_{boiler} * \eta_{el,PB} \tag{1}$$

where ρ_{biogas} is the biogas density (1.23175 kg/m^3); LHV_{biogas} is the biogas lower heating value (13700 kJ/kg)[8]; η_{boiler} is the efficiency of boiler (85%)[7] and $\eta_{el,PB}$ is the power block efficiency (27.1%)[7].

The simulations are carried out with a new load curve reported in Figure3. The demand is shifted down of 3.1 MW in order to take into account the contribution of biogas fuel. The biogas itself covers about 62% of the peak power of the plant of 5 MW.

The power block is set with a scale factor of 0.38, that means it works with only the 38% of its original nominal power, because the remaining part is driven by the boiler as written above.

Results of the two parts are then put together in a spreadsheet, which also includes the economic evaluation, and compared with other simulations. In fact, while the boiler part is all the same for every simulation, the characteristics of the solar part of the system can change. In fact, 42 annual simulations were done changing 7 sizes of solar field and 6 sizes of thermal energy storage. Every simulation is labelled using respective Solar Multiple (SM) value and Full Load Hours (FLH) value. SM ranges from 1.03 to 4.13 and indicates the fraction between nominal thermal power

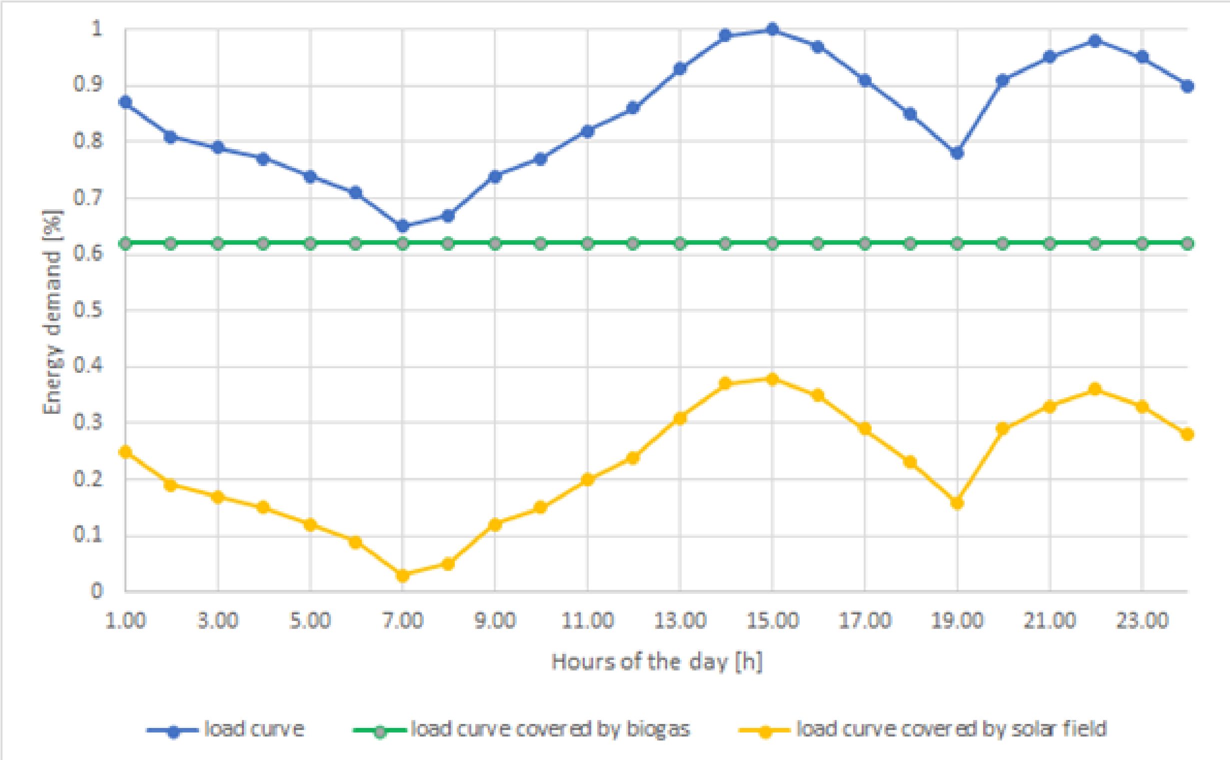

FIGURE 3. Normalized electrical load curve

produced by the solar field and the nominal thermal power of the power block. FLH is a value that ranges from 1 to 15 hours and it is calculated dividing the storage net energy capacity per the nominal thermal power of the power block.

All the simulation are compared to check which is the best configuration. If thermal energy generated by the solar sub-system is not sufficient to satisfy the electrical load, methane is used to cover the gap. The following boundaries are taken into account for the selection of the best solar plant configuration:

1. Methane hybridization < 10%
2. Maximum dumped heat fraction < 15%
3. Overall solar to power efficiency > 15%
4. LCoE < 100 €/MWh

The dumped heat is energy loss during plant running given by an excessive solar energy respect electrical energy demand. The dumped heat increases with solar field dimension or it can decrease with storage capacity rise. Molten salts storage is a thermal reservoir that accumulates energy during the day and releases this energy during night loading the power block. Considering the economics, the most important result is Levelized Cost of Electricy calculated as follow:

$$LCoE = \frac{CAPEX * ANNUITY + OPEX}{E_{el}} \tag{2}$$

$$ANNUITY = \frac{DR * (1 + DR)^T}{(1 + DR)^T - 1} \tag{3}$$

where CAPEX [€] are capital expenditures; OPEX [€] are operational expenditures; E_{el} [MWh] is the annual electrical energy production; DR [%] is the discount rate (fixed to 6% for this project [6]) and T [year] is the plant lifetime (fixed to 25 years).

Results and discussion

Figure 4 shows the trends of the electrical energy produced by the CSP plants versus SM and FLH values. Obviously, electricty production is higher with high value of SM. However the trend is not linear, mostly at high SM value over 2. Configurations with FLH = 9 presents the same electricity production of FLH 15 configurations, therefore the choice of FLH = 9 is the best in terms of economic point of view and energy storage effectiveness.

Figure 5 depicts the share of sources used versus the SM parameter in the configuration with FLH = 9. Biomass value is almost constant at 70% because the biogas production is not affected by the SM. Solar share increases and methane integration decreases with the SM value. The configuration that respect the boundaries listed in the previous paragraph is that one with SM = 2.07. This configuration has a dumped heat fraction of 10.22 %, a methane hybridization (methane share) of 8.73%, a solar share of 20.73%, a biomass share of 70.53 %, a capacity factor of 47.59% defined as the ratio between average power production and power block peak power.

Concerning the LCoE, Figure 6 reports the trends of LCoE Versus FLH and with several SM configuration. Again the FLH 9 configuration is the more convenient for every SM values. The configuration that satisfy the goal of the project is that one with SM = 2.07 and FLH = 9. The most important technical details regarding this configuration are reported in Table 1. Simulation results concerning the whole system and sub-components are also reported in Table 1. Another important result is the overall electrical efficiency of the system of 11.5% similar to the value obtained in [4].

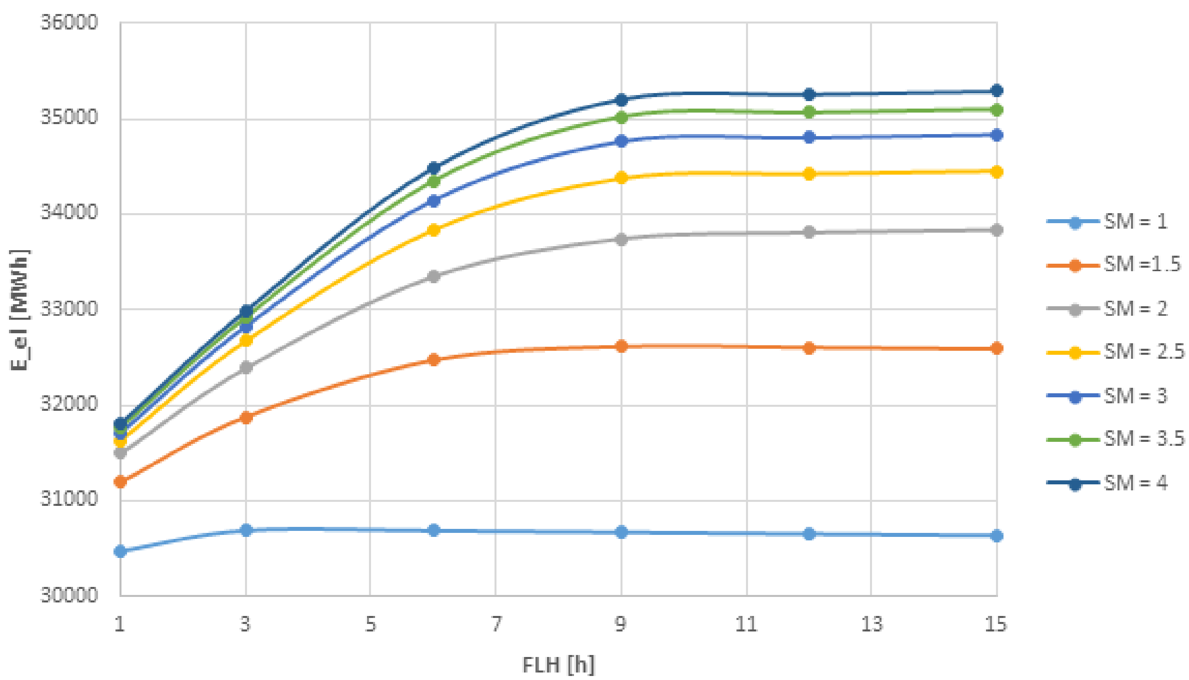

FIGURE 4. Annual electricity produced by the CSP Vs. FLH and SM

Figure 7 depicts the Greenius software interface where the results obtained from the simulation of the 8th of July are reported. This is the day with the higher daily irradiation, in fact solar share is higher compared to annual average solar share. 110.08 MW of solar thermal energy is used by the PB, however the total solar thermal energy is 170 MWh and 60 MWh are dumped heat lost in atmosphere.

Figure 8 shows CAPEX and annual OPEX costs of the plant. Total investment cost is about 28.5 M€and specific investment cost per unit of nominal power is 5.7 M€$/MW_{el}$. SF is the most expensive sub-system (32% of the CAPEX) followed by the AD (32% of the CAPEX) and by the PB (14% of the CAPEX). Regarding OPEX cost, AD is the most expensive sub-system (36% of the OPEX) followed by the PB (25% of the OPEX) and by the Boiler (20% of the OPEX including methane cost). Calculated LCoE of this configuration is 97.32 €$/MWh_{el}$, a good results compared to literature data [4].

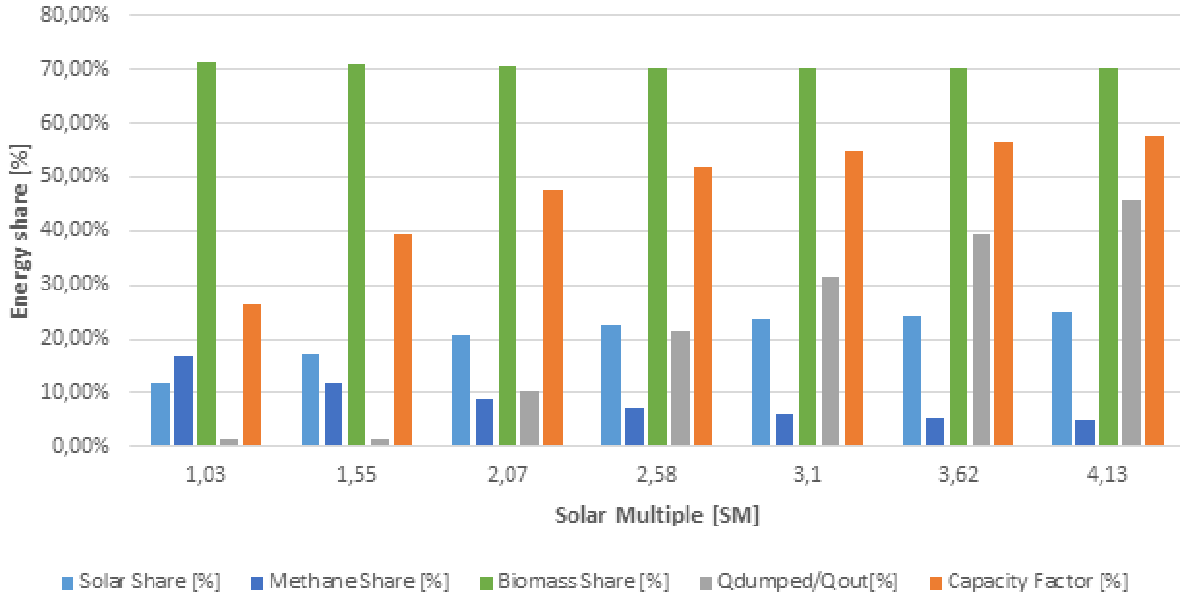

FIGURE 5. Energy shares with FLH 9 configuration Vs. SM

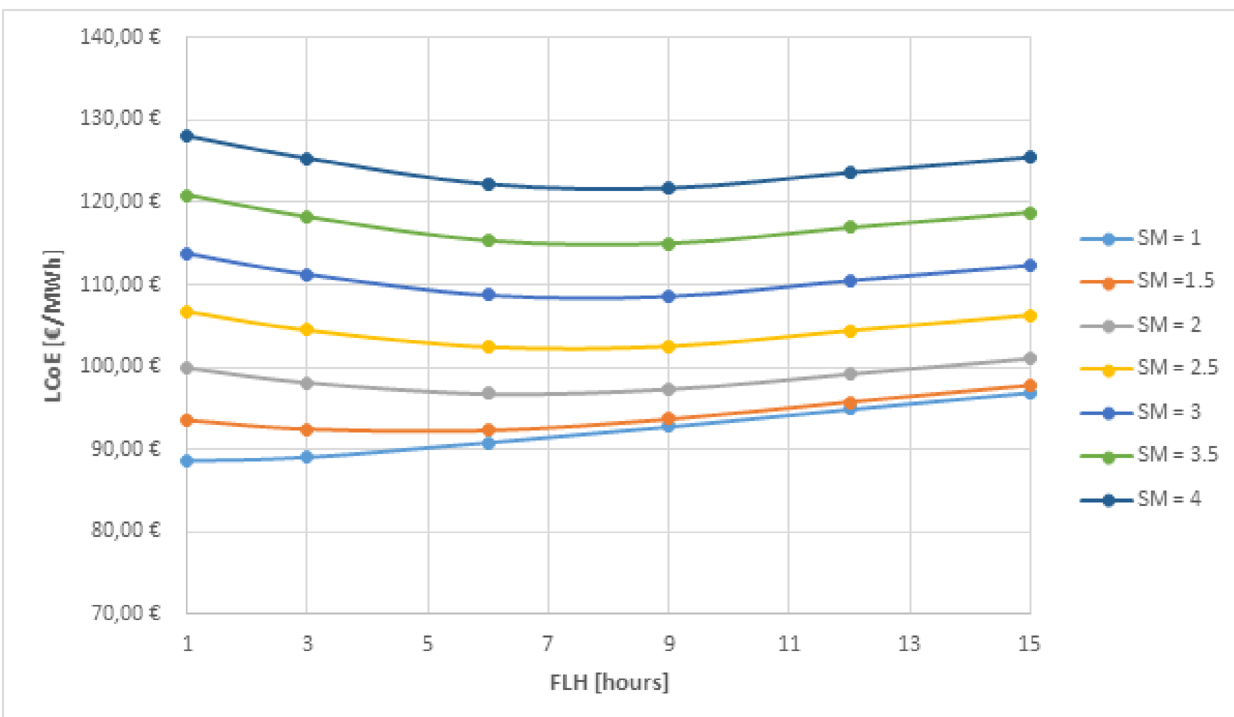

FIGURE 6. Energy shares with FLH 9 configuration Vs. SM

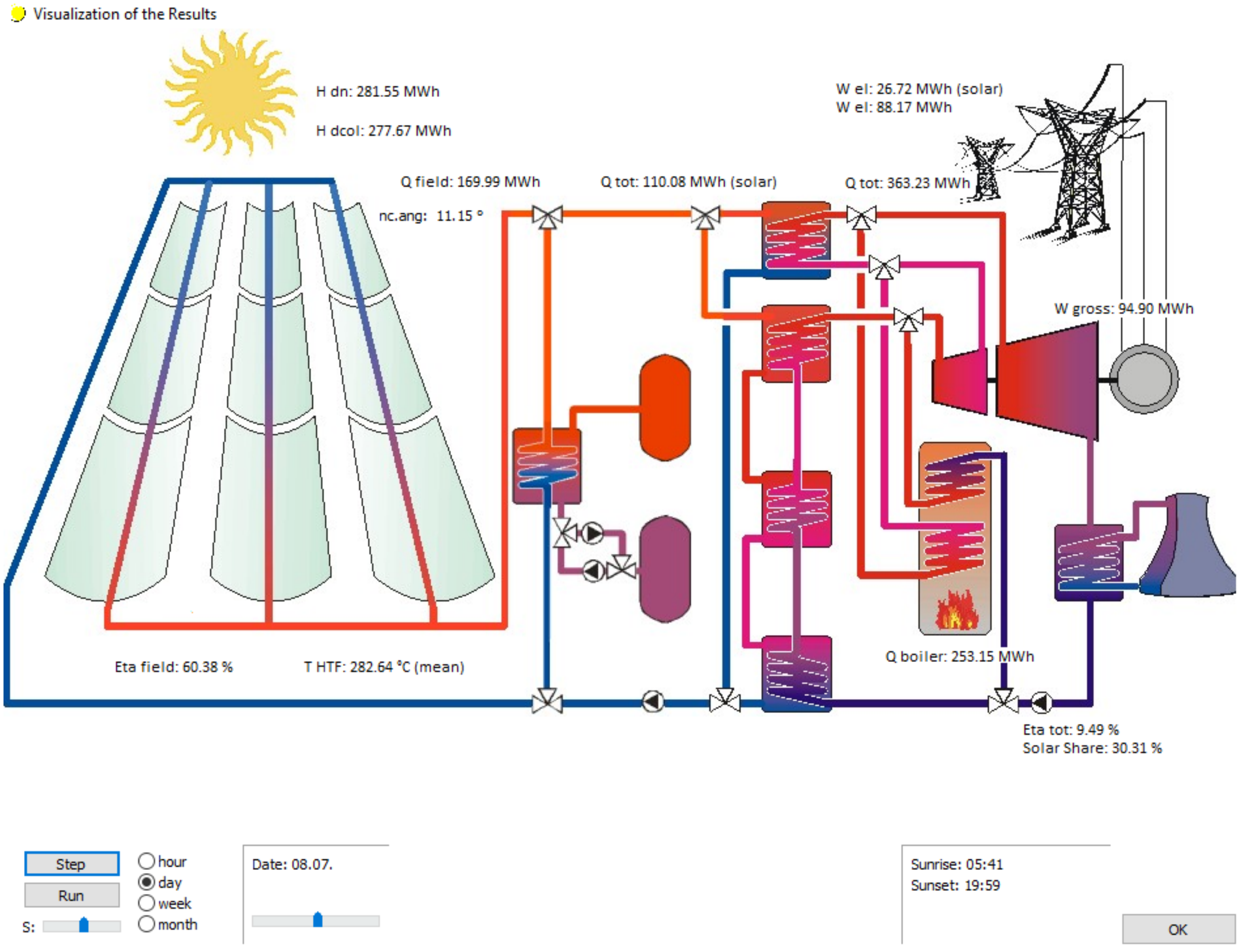

FIGURE 7. Greenius simulation interface whit 8th July results

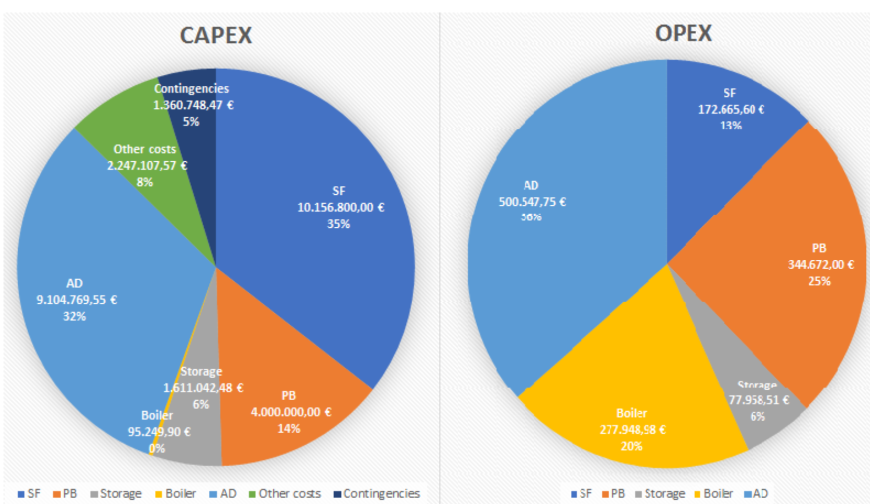

FIGURE 8. CAPEX and annual OPEX of the SM=2.07 FLH=9 CSP plant configuration

TABLE 1. CSP hybrid system technical details [7] and annual simulation results given by Greenius

COLLECTORS			
Collector model	-	SL4600	-
Absorber model	-	Huiyin70 2015	-
Collector lenght	l	120	m
Aperture width	a	4.6	m
Effective mirror area	A_{coil}	529	m^2
Nominal optical efficiency	eta_{OPT}	77.10	%
SOLAR FIELD (SF)			
Land use	A_{tot}	2581372	m^2
Direct Normal Irradiance	DNI	800	W/m^2
Annual Direct Normal Irradiance	DNI_{year}	2629.93	kWh/(m^2 anno)
Nominal Thermal Output	P_{th}	13.459	MW_{th}
Number of loops	N_{loops}	12	-
Number of collectors per loop	$N_{coll,loops}$	4	-
Collectors effective area	$A_{sf,eff}$	25392	m^2
Solar Multiple	SM	2.07	-
SF Inlet Temperature	T_{in}	204	^oC
SF Outlet Temperature	T_{out}	305	^oC
SF mean Temperature	T_{mean}	255	^oC
Heat Transfert Fluid	HTF	Therminol VP-1	-
Annual heat generated by the solar field	$Q_{out,field}$	30248.082	MWh_{th}
Specific thermal field output	$Q_{field,spec}$	1.191	MWh_{th}/M^2
Mean annual SF efficiency	η_{th}	45.30	%
DNI multiplied by time step and total collector area	H_{dn}	66779.183	MWh
Annual Dumped solar heat	$Q_{dumped,load}$	3091.233	MW_{th}
Dumped solar heat and SF Output ratio	$Q_{dumped,load}/Q_{out,field}$	10.22	%
STORAGE			
Net capacity	V_{stor}	58626	kWh
Full Load Hours	FLH	9	hours
Fluid Mass	m_{stor}	1861.61	tons
Maximal charging	P_charge	6.514	MW_{th}
Maximal discharging	$P_discharge$	6.514	MW_{th}
Rel. losses in 24h	$Q_{stor,loss}$	1	%
Input Temperature difference	ΔT_{in}	11	^oC
Output Temperature difference	ΔT_{out}	11	^oC
Pumping parasitics	W_{par}	0.003	W_{el}/W_{th}
Minimal content	V_{min}	5862.6	kWh_{th}
BOILER			
Boiler nominal thermal power	P_{boil}	10600	kW_{th}
Biogas Lower Heating Value	LHV_{biogas}	13700	kJ/kg
Methane Lower Heating Value	$LHV_{methane}$	43500	kJ/kg
Mean annual boiler effiiency	η_{boiler}	85	%
Heat input	$Q_{boiler,in}$	122167	$MWht_{th}$
Annual heat generated	Q_{boiler}	103842	MWt_{th}
Annual biogas consumption	$m_{biogas,year}$	28565.049	tons
Average biogas consumption	m_{biogas}	3260.85	kg/h
Annual methane consumption	$m_{methane,year}$	1114.090	tons
POWER BLOCK (PB)			
Model	-	SIEMENS - BIOSOL 5 MW	-
PB Nominal Thermal Power	$P_{th,PB}$	17.143	MW_{th}
PB Nominal Electrical Power	$\eta_{el,PB}$	29.20	%
PB Nominal Heat Output	$Q_{th,PB}$	12137.244	MW_{th}
Nominal Power to Heat ratio	$P_{el}/Q_{th,PB}$	41.24	%
TOTAL SYSTEM			
Annual useful heat from SF and boiler	$Q_{SF} + Q_{boiler} - Q_{dump}$	130999	MW_{th}
Annual electrical energy generation	P_{el}	37084	MWh_{el}
Mean annual PB efficiency	$\eta_{el,PB}$	28.3	%
Mean annual CSP system electrical efficiency	$\eta_{tot,SF+BIOGAS}$	11.51	%
Capacity factor	C	47.59	%
Solar share	f_{solar}	20.73	%
Biomass share	$f_{biomass}$	70.53	%
Methane share	$f_{methane}$	8.73	%

CONCLUSIONS

A case study regarding the hybridization of concentrated solar power plant with biogas from urban waste anaerobic digestion was simulated considering an electrical load curve and meteorogical data of a small algerian city. Renewable sources are not sufficient to self sustain the electrical demand in the winter season where a small hybridization using methane was used. Several configurations of the CSP plant with thermal storage were simulated in order to satisfy the boundaries condition of the project. The power plant with SM=2.07 and FLH=9 showed the best compromise in terms of solar share (20.73%); biogas share (70.53%) and dumped solar heat fraction (10.22%). The economical analysis performed on this configuration showed a reasonable value of LCoE equal to 97.32 €/MWh_{el}.

ACKNOWLEDGMENTS

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