DEMOSOFC

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"DEMOnstration of large SOFC system fed with biogas from WWTP"

Deliverable number 2.5

Cost/benefit analysis of the system

Task T2.5: Cost/benefit analysis of the system

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Abstract:

Wastewater treatment is currently a very energy and greenhouse gas intensive process. An important opportunity to reduce both of these quantities is via the use of biogas produced within the treatment process to generate energy.

This deliverable studies the optimal energy and economic performance of the wastewater treatment facility in Collegno (Turin) retrofitted with a solid oxide fuel cell (SOFC) based combined heat and power (CHP) plant. An optimisation framework is formulated and then applied to determine cost, energy and emissions performance of the retrofitted system when compared with conventional alternatives.

Results show that present-day capital costs of SOFC technology mean that it does not quite compete with the conventional alternatives. But if either a modest carbon price of 22 €/t of CO_2 were imposed, or technological learning leads to capital cost reductions of the technology, then SOFC can become competitive in this application.

Keyword list: biogas, SOFC, mathematical, system design, techno-economic analysis, WWTP, optimization.

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1. Purpose of this document

The cost/benefit analysis of the DEMOSOFC plant is carried out using an MILP (mixed integer linear programming) modelling approach to the optimal unit commitment applied to a sub-MW WWTP retrofitted with a biogas-fed SOFC CHP plant. The CHP system operates in parallel with electricity imported from the grid and a supplementary boiler, which can be fuelled with either natural gas or biogas. As such, the annual thermal and electrical loads of the WWTP can be met either using on-site heat and electricity generated from the SOFC-based CHP or exploiting the supplementary boiler and electricity bought from the grid. The model decides the optimal unit commitment on an hourly interval minimising the system operating costs and thus defines which fuel mix fulfils the thermal and electrical loads. Dynamics of SOFCs are modelled imposing minimum up- and down-time as well as ramp rate constraints. Sensitivity analyses are performed on key cost factors and pathways for technological learning on SOFC manufacturing are laid out.

The optimisation approach chosen can give relevant insights into medium scale-CHP commercialisation as an emerging technology, showing potentials and opportunities for improvements both for SOFC manufacturers and end-users. Manufacturers can investigate the impact of design decisions (i.e. scale), operating and technological variables (i.e. thermal and electrical output from SOFCs, minimum up- and down-time, ramp rates) on the commercialisation of their technology; end-users can assess opportunities and risks of adopting the technology in their business. Annual biogas production, thermal and electrical loads on an hourly basis were supplied by the WWTP operating in Collegno, near Torino (Italy) [1].

2. **Problem statement**

The sub-MW CHP system to be installed in the WWTP of Collegno includes 3 biogas-fed SOFC stack modules, a supplementary boiler, a biogas holder and a connection for electricity and natural gas between the system and the grid (see
Figure 1). The anaerobic digester dynamic behaviour has not been modelled, but the hourly biogas flow rate of a real WWTP is an input to the optimisation. The dynamic behaviour of the SOFC-based CHP is captured through minimum up- and down-time, ramp limits, constraints for energy consumption during start-up/shut down, as detailed later in the section Mathematical formulation.
The economic analysis is based on the optimal CHP unit commitment which defines the minimum cost operating strategy.
The problem can be stated as follows. Given:

- the techno-economic characterisation of each single SOFC stack module in terms of
  - capacity
  - piecewise profile for electrical and heat efficiency
  - capital, maintenance and stack replacement costs
  - ramp rates
  - minimum up- and down-times
- the techno-economic characterisation of the clean-up system (i.e. capital and maintenance costs)
- the supplementary integrated boiler capacity
- the supplementary boiler efficiency profile, which is assumed constant despite variations of fuel inlet flow and quality (i.e. natural gas and biogas mixtures)
- the minimum and maximum biogas holder levels
- the annual electricity demand profile of the WWTP on an hourly basis
- the annual thermal demand profile of the WWTP on an hourly basis

The model minimises the total annual costs of the energy provision system which fulfils the WWTP thermal and electrical demand and defines its optimal operating strategy hour-by-hour.
As such, the decision variables are

- the dispatch state of each SOFC module on an hourly basis (which defines number and occurrence of shut downs and start-ups in a year)
- the electrical and thermal output of each SOFC stack module on an hourly basis
- the boiler thermal output on an hourly basis

- the electricity and natural gas bought from the grid and associated CO_2 emissions on an hourly basis
- the biogas flow used in the SOFCs on an hourly basis
- the biogas holder levels on an hourly basis
- the amount of biogas unexploited (i.e. flared) on an hourly basis

Appendix A reports the symbols of the decision variables as reported in the mathematical formulation.

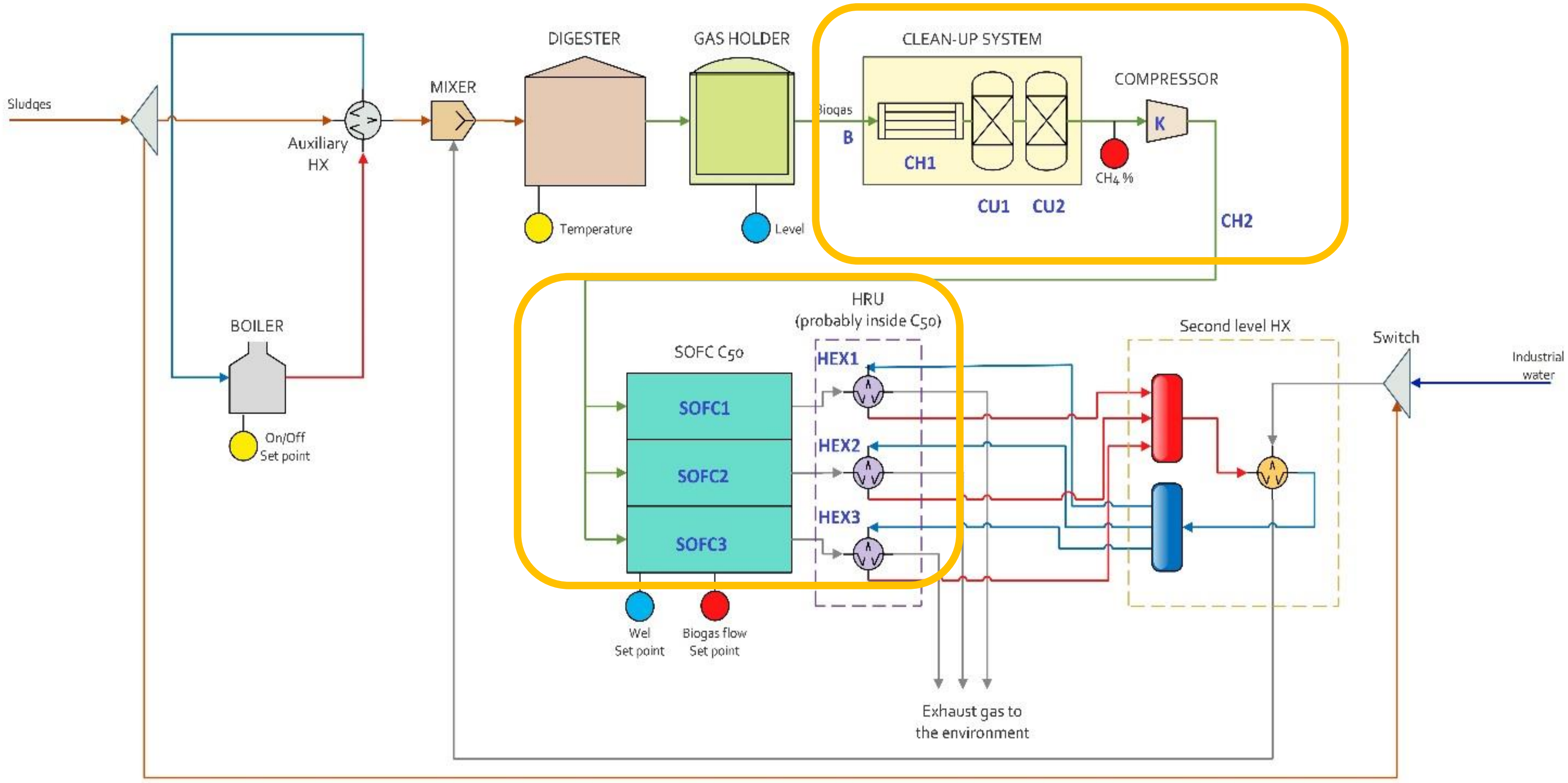


Figure 1: WWTP layout. Orange blocks highlight the equipment included in the investment cost estimation

The SMAT Collegno WWTP [1], located in the Turin area, currently uses biogas to supply a boiler and partially provide the heat required by the plant. According to the retrofitting project, the same biogas after clean-up will be also used to feed the SOFC modules which will work as a sub-MW CHP unit, supplying both heat and power to the system. The WWTP has a capacity corresponding to 180,000 EP. The average electrical and thermal loads are around 640 and 340 kWh in a year. Thermal energy requirement is mainly due to maintaining the digester temperature generally above the 40 °C in order to allow the biological process to succeed.

Biogas composition might vary in a year due to change in quality and quantity of the wastewater treated at the plant. The technoeconomic appraisal is here performed considering a biogas with a lower heating value of 21,501 kJ/m^3. A constant chemical composition of biogas was assumed throughout the year, as reported in *Table 1*: Assumed biogas composition, which meets the quality specifications for supplying an SOFC system.

Table 1: Assumed biogas composition

Compound	Molar fraction
CH_4	0.65
CO	0
CO_2	0.331
H_2	0
H_2O	0.01
O_2	0.002
N_2	0.007

3. **Mathematical formulation**

The MILP model here described extends the optimal unit commitment problem developed by [2] and the economic appraisal proposed by [3] to optimise the operating strategy of a sub-MW CHP system integrated to a WWTP where *n* homogeneous SOFC generators are installed. In the following, the objective function is first presented, then the equations concerning the fulfilment of energy balances, fuel cell and system constraints are outlined. A schematic of the system modelled is proposed in *Figure 2*.

The full list of symbols is reported in Appendix A.

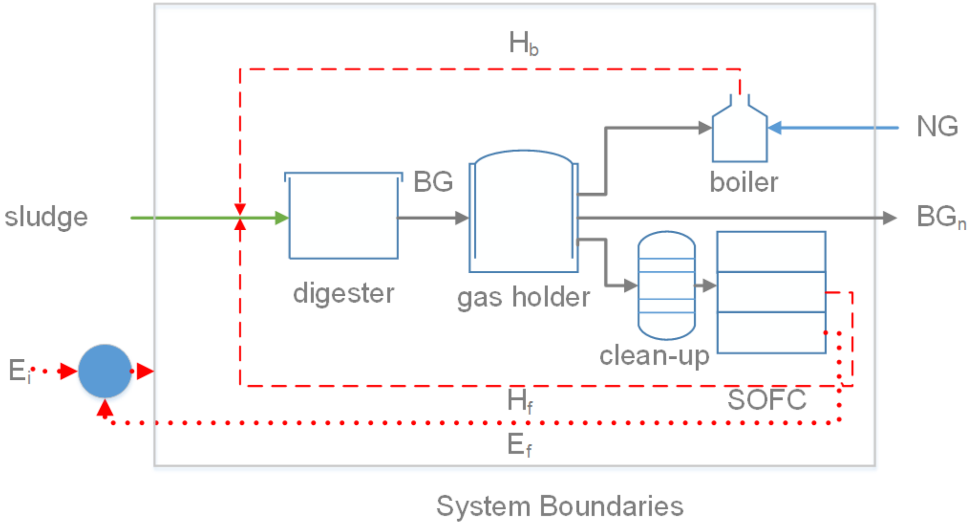


Figure 2: System boundaries of the study and relevant energy flows. BG indicates the biogas produced from anaerobic digestion, BGn is the biogas which remains unexploited, Ef is the electric energy generated from the SOFC, Ei is the electricity bought from the grid, Hb is the thermal energy generated from the boiler, Hf is the thermal energy obtained from heat recovery of the SOFC system.

3.1 Objective function

The model minimises the CHP system total annual costs, *TC*, which consist of the sum of fixed costs and variable operating costs over the total number of hours *t* in a year:

- fixed costs include maintenance costs for SOFC and clean-up systems which are proportional to the stack nameplate capacity ($n \cdot Pnom$) according to the unit maintenance and clean-up costs, *UMC* and *UOC* respectively;
- variable operating costs account for the costs related to the fuel sent to the supplementary thermal unit (NGb_t), electricity bought from the grid (Ei_t) as well as the carbon price *cp* associated to the energy mix carbon intensity (*ge*, *ee*)

$$TC = \sum_{t=1}^{8760} NGb_{\,t} \cdot (gp_t + cp \cdot ge) + Ei_t \cdot (ep_t + cp \cdot ee) + (UMC + UOC) \cdot n \cdot Pnom$$

Equation 1: Total costs definition

3.2 Energy balance

The sub-MW CHP system has to obey the biogas balance in *Equation 2* which reflects the energy flows in Figure 2 System boundaries of the study and relevant energy flows. BG indicates the biogas produced from anaerobic digestion, BGn is the biogas which remains unexploited, Ef is the electric energy generated from the SOFC, Ei is the electricity bought from the grid, Hb is the thermal energy generated from the boiler, Hf is the thermal energy obtained from heat recovery of the SOFC system.The flow of biogas from the anaerobic digester BGi_t at time t, is split among these possible destinations:

- fuelling the boiler (BGb_t),
- fuelling the SOFC f during its regular operation r $X_{t,r,f}/\eta_r^{fel}$, or during start ($BG_{t,f}$) and stop events ($BGD_{t,f}$) [1]
- being flared (BGn_t)
- being stored in the biogas holder (GH_t)

$$\mathrm{BGi}_t - \mathrm{BGb}_t - \sum_{r,f=0}^{r=2,f=3} \frac{\mathrm{X}_{t,r,f}}{\eta_r^{fel}} - \sum_{f=0}^{f=3} BGS_t - BGD_{t,f} + BGn_t = GH_{t+1} - GH_t$$

Equation 2: Biogas balance

Equation 3 concerns the system thermal balance. Accordingly, the on-site heat demand (DTL_t) is met by a combination of useful heat from the committed SOFC units f operating at regime r $X_{t,r,f}/\eta_r^{fel}$, the supplementary boiler where both natural gas (NGb_t) and biogas (BGb_t) can be burned. The supplementary boiler is assumed to operate at the same efficiency η^b with both the fuels.

$$\mathrm{NGb}_t + \mathrm{BGb}_t \cdot \eta^b + \sum_{r,f=0}^{r=2,f=3} \frac{\mathrm{X}_{t,r,f} \cdot \eta_r^{fth}}{\eta_r^{fel}} = \mathrm{DTL}_t$$

Equation 3: Thermal balance

Finally, *Equation 4* guarantees the electricity balance of the system. The on-site electricity demand is made up of:

- the WWTP electrical demand Ed_t,
- the clean-up utility u electrical demand, proportional to the biogas used in the SOFCs $X_{t,r,f}/\eta_r^{fel}$ according to the unit energy consumption UEC_u of utility u
- the electricity absorbed during start-ups $PSS_{t,f}$ and shut-downs $PSD_{t,f}$ of each cell f

As stated in *Equation 4*, at every hour t, the on-site electrical demand is met by a combination of power generated from the SOFC units $X_{t,r,f}$ and electricity from the grid Ei_t.

[1] As detailed in the following, the electrical and thermal performance of the fuel cell have been modelled using two regimes: nominal condition and partial load operation

$$Ei_t + \sum_{r,f=0}^{r=2,f=3} \mathrm{X}_{t,r,f} = Ed_t + \sum_{u,f,r}^{u=NU,f=3,r=2} UEC_u \cdot \frac{\mathrm{X}_{t,r,f}}{\eta_r^{fel}} + \sum_{f=0}^{f=3} \left(PSS_{t,f} + PSD_{t,f}\right)$$

Equation 4: Electrical balance

3.3 Fuel cell constraints

Equation 5 and *Equation 6* define the minimum up- and down-time constraints for the SOFC. The formulation is based on the approach by [2] and constrains the value of the binary variable $\upsilon_{t,f}$ which defines the commitment state of each SOFC *f* at time *t*.

$$\upsilon_{t-1,f} - \upsilon_{t,f} \geq \upsilon_{\tau,f}, \qquad \tau \in upt_t \ t.c. t \geq \ 2$$

Equation 5: Minimum up-time

$$\upsilon_{t-1,f} - \upsilon_{t,f} \geq 1 - \upsilon_{\tau,f}, \qquad \tau \in dot_t \ t.c. t \geq \ 2$$

Equation 6: Minimum down-time

The physical motivation behind these two constraints is to prevent the SOFC thermal cycling and degradation processes. As such, once committed, the cell is forced to remain switched on for a minimum number of hours equal to the minimum up-time (*Equation 5*: Minimum up-time). In a similar fashion, once the cell is switched off, it is constrained to remain at that stage at least for a number of hours equal to the minimum down-time (*Equation 6*: Minimum down-time).

Power ($PSU_{t,f}$, $PSD_{t,f}$) and biogas ($BGS_{t,f}$, $BGD_{t,f}$) respectively consumed during start and stop processes are calculated distributing the average rate of electricity (*PSUabs*, *PSDabs*) and biogas (*BGSabs*, *BGDabs*) absorbed over the entire duration of the start (*Equation 7* and *Equation 9*) and stop (*Equation 8* and *Equation 10*) process. The energy consumed was used to then determine the costs associated with start/stop process of the generator.

$$PSU_{t,f} \geq PSUabs \cdot \left(\upsilon_{t,f} - \upsilon_{t-tup,f}\right), t \geq tup + 1$$

Equation 7: Energy absorbed at start-up

$$PSD_{t,f} \geq PSDabs \ \cdot \left(1 - \upsilon_{t,f}\right)$$

Equation 8: Energy absorbed at shut-down

$$BGS_{t,f} \geq BGSabs \cdot (\upsilon_{t,f} - \upsilon_{t-tup,f}), t \geq tup + 1$$

Equation 9: Biogas absorbed at start-up

$$BGD_{t,f} \geq BGDabs \cdot (1 - \upsilon_{t,f})$$

Equation 10: Biogas absorbed at shut-down

If the SOFC f state is on, the generator can be tuned to work at a specific operating regime which makes minimum the total system cost. The logic condition defined in *Equation 11* links the value of the binary variable for the SOFC state of commitment ($\upsilon_{t,f}$) with the value of the binary variable for the SOFC regime ($\chi_{t,r,f}$). Accordingly, when the SOFC is off, all the $\chi_{t,r,f}$ equal zero; viceversa, when the SOFC is on, only one operating regime can be selected.

$$\sum_{r=0}^{r=2} \chi_{t,r,f} = \upsilon_{t,f}$$

Equation 11: SOFC operation regime selection

Additional constraints are defined to link the SOFC electrical output with the piecewise profile of the efficiency. The electricity output of an SOFC is limited by the SOFC nameplate capacity (*Pnom* in *Equation 12*); each regime also has to operate between a lower (PRL_r) and an upper bound (PRU_r), as stated respectively in *Equation 13* and *Equation 14*. *Equation 13* also sets the presence of a minimum set-point for the SOFC operation, representing a lower bound to the economic and technical feasibility region of the SOFC operation.

$$\sum_{r=0}^{r=2} \mathrm{X}_{t,r,f} \leq \upsilon_{t,f} \cdot Pnom$$

Equation 12: Limit on SOFC capacity

$$\mathrm{X}_{t,r,f} \geq PRL_r \cdot \chi_{t,r,f}$$

Equation 13: Lower limit on SOFC capacity per regime

$$\mathrm{X}_{t,r,f} \leq PRU_r \cdot \chi_{t,r,f}$$

Equation 14: Upper limit on SOFC capacity per regime

The rate at which the SOFC can change its electrical output level is constrained imposing a maximum ramp up rate (*rup* in *Equation 15*). This reduces mechanical stress caused by thermal gradients in the SOFC.

$$rup \geq \left(\mathrm{X}_{t,r,f} - \mathrm{X}_{t-1,r,f}\right), t \geq 2$$

Equation 15: Constraint on rump-up

3.4 System constraints

In a similar way to the nameplate capacity limit imposed to the SOFCs in Equation 12, physical capacity limits are modelled for all the CHP system units: *Equation 16* defines a lower (*GHL*) and an upper (*GHU*) bound to the biogas storage; *Equation 17* sets that the boiler thermal power must not exceed its capacity (*BCap*).

$$GHL \leq GH_t \leq GHU$$

Equation 16: Limit on gas holder capacity

$$BCap \geq (NGb_t + BGb_t) \cdot \eta^b$$

Equation 17: Limit on boiler capacity

Finally, a periodic condition is set to ensure that the CHP operational strategy applies from one year to the next one until the end of the system lifetime. The periodic condition is stated with *Equation 18* where the gas holder level at the beginning of the year has to equal the value at the end of the year.

$$GH_1 = GH_{8760}$$

Equation 18: Periodic condition on gas holder levels

4. **Real-world industrial case study**

A techno-economic assessment was performed for the retrofit of the energy supply system of a sub-MW WWTP operating in Collegno, Italy. The heat supply to the facility currently relies on a gas boiler, while electricity is bought from the grid. The retrofit plan involves the installation of a 3-module SOFC-based CHP system fuelled with biogas. Selected technical characteristics of the current energy supply system (i.e. boiler and gas holder), of best available alternative technologies (i.e. MGT) as well as of the SOFC system, are reported in *Table 1*. *Table 7* provides all the technical characteristics of the planned SOFC installation as provided by the cell manufacturer: lifetime of an SOFC module and SOFC stack, net AC (alternating current) capacity, minimum up/down time, power absorbed and biogas consumed during start-up and down-time events. *Table 7* also reports assumptions on SOFC cost trends which have been based on the methodology proposed by *[4]*.

In the current configuration, a gas holder operates approximately at atmospheric pressure, receives the biogas from the digester and flattens the rate fluctuations before the boiler. According to the WWTP retrofitting project, a biogas clean-up and a 3-module SOFC system will be located in an additional branch of the gas holder downstream.

Table 2: Selected techno-economic performance of boiler and gas holder, which belong to the currently installed configuration for heat supply to the WWTP; of MGT and SOFCs

Boiler technical input	unit	value
Capacity	kW	1,600 (estimated)
Efficiency	%	85 (estimated)
Maintenance costs	% of CAPEX	3 [5]

Gas holder technical input	unit	value
Minimum capacity	kWh	1,791.75 [6]
Minimum capacity	m^3	300 [6]
Maximum capacity	kWh	8,361.5 [6]
Maximum capacity	m^3	1,400 [6]

MGT technical input	unit	value
Capital costs	€/kW	2,261 [7]
Maintenance costs	% of CAPEX	4 [5]
Net AC Power	kW	174.9 [6]
Power-to-heat ratio	%	60 [7]
Electrical efficiency	%	22 [7]

SOFC technical input	unit	value
Capital costs	€/kW	8,303 [4]
Replacement costs	€/kW	1,223 [4]
Maintenance costs	€/kW/yr	72 [4]

SOFC technical input	unit	value
Capital costs	€/kW	8,303 [4]
Replacement costs	€/kW	1,223 [4]
Maintenance costs	€/kW/yr	72 [4]

SOFC nominal condition	unit	value
Stack current	%	50 — 100 [6]
Net AC Power	kW	29.65 — 58.3 [6]
Thermal efficiency	%	27 [6]
Electrical efficiency	%	53.8 [6]

SOFC partial condition	unit	value
Stack current	%	30 —50 [6]
Net AC Power	kW	16.6 — 29.65 [6]
Thermal efficiency	%	31.5 [6]
Electrical efficiency	%	41.2 [6]

Electrical and thermal efficiencies in an SOFC vary with the stack current and, consequently with the rate of biogas used. In order to balance a more realistic description of the cell behaviour while keeping the model linear and computationally tractable, the dynamic profile of the thermal and electrical efficiencies of an SOFC has been modelled using a piecewise linear function having two operating regimes. One regime describes the operating conditions closer to the cell nominal ones: here the cell exhibits the best performance and can exploit up to 100 % of the biogas rate allowed into the system. A second regime characterises the SOFC partial load operations. Relevant features of the two regimes are summarised in *Table 2*.

5. **Results and discussion**

The model has been implemented using the GAMS® software and solved with the CPLEX solver. A typical optimisation run for a 3-module SOFC involves about half a million variables and solves in a few minutes.

Description of the comparative scenarios

In addition to the SOFC-based CHP, a series of scenarios was assessed adapting the original model for optimal CHP dispatch. A framework of comparative studies was built up to help shaping the SOFC technology introduction and deployment strategies. The scenarios are described in the following:

- Scenario A: represents the current configuration of the system which relies on heat generated by the co-fuelled (natural gas and biogas) boiler. The modelling framework presented in section *Mathematical formulation* has been adapted substituting the SOFC-related costs with the boiler-related ones from the objective function, noting that capital costs are not applicable as the boiler belongs to the current configuration of the WWTP; setting to zero the SOFC contribution to heat and power generation as well as the energy for start/stop events in the energy balances (*Equation 2* — *Equation 4*); removing the SOFC operating constraints (*Equation 5* — *Equation 15*).
- Scenario B: considers a hypothetical WWTP retrofit based on the installation of an MGT. This technology was chosen as one of the most notable competing technologies to SOFCs. The MGT system was given a total net AC capacity equal to the one of the CHP system based on SOFCs (174.9 kW) as described in the actual WWTP retrofitting plan. The MGT was modelled as integrated to the WWTP, thus providing it with the generated heat and electricity. The MGT was assumed to operate at 22 % of net electrical efficiency and 60 % of power-to-heat ratio. The unit capital cost assumed was 2,261 € /kW *[7]* while the

maintenance costs were set to 4 % of the investment expenditure *[5]*. The modelling framework presented in section *Mathematical formulation* substituting the SOFC-related costs from the objective function with the maintenance and capital costs related to the MGT; turning the SOFC biogas consumption, contribution to heat and power generation into the corresponding variables for the MGT system as well as removing the energy use for start/stop events from the energy balances (*Equation 2 — Equation 4*); removing the SOFC operating constraints (*Equation 5 — Equation 15*). A capacity constraint was also introduced to limit the maximum generated electricity by the MGT. Differently from SOFCs, the MGT was modelled assuming that both biogas and natural gas could be used as fuels.

- Scenario C: refers to the actual proposal for the WWTP retrofit. As such, it considers the integration of the sub-MW SOFC-based CHP system to the WWTP. It includes 3 biogas-fed SOFC stack modules having a total net AC capacity of 174.9 kW, a supplementary boiler, a biogas holder and a connection for electricity and natural gas of the system to the grid
- Scenario D: stems from scenario C (i.e. the WWTP retrofitting plan based on 3 SOFC modules) and also includes an upgrade in the sludge WWTP handling section, introducing centrifugal thickening before the anaerobic digester. The increased capital investment required for the installation of the necessary equipment units, would be justified by the reduction in the thermal loads as the total suspended solids would rise from 1.91 wt. % to 8 wt. %
- Scenario E: similar to D, but involves the installation of a dynamic sludge thickening rather than a centrifugal one before the anaerobic digester. This technological solution is less capital intensive than D and allows an increase of the total suspended solids up to 5 wt. %.
- Scenario F: models the WWTP retrofitted with the 3-module SOFC-based CHP, but operating in the UK market rather than in the Italian context. As such, the country-specific costs for natural gas and electricity are used.
- Scenario G: models the WWTP retrofitted with the 4-module SOFC-based CHP

The cost metric used to assess the scenarios was the equivalent annual cost and the interest rate was set equal to 2.5 %. All the cases settled in the Italian market (A — E and G) share these economic inputs:

- natural gas price constant throughout the year and equal to 0.06 €/kWh, which is typical for WWTP plants *[6]*
- electricity hourly price profile was based on industrial prices for WWTPs in 2016 as provided by SMAT *[6]*

In the UK-based case study, energy prices were updated as retrieved in *[8]*.

The CO_2 emissions of the WWTP were estimated using the carbon intensity of the energy imported by the system, according to the following assumptions:

- natural gas emission factor, 0.202 $kgCO_2$ per kWh *[9]*
- electricity emission factor, 0.468 $kgCO_2$ per kWh *[10]*

Optimal operational strategies in the modelled scenarios

The modelling framework presented in section *Mathematical formulation* was applied with the relevant changes highlighted in section *Real-world industrial case study* to define the optimal dispatch, operating strategy (i.e. unit commitment, fuel mix), costs and emissions of the energy supply system integrated to the WWTP.

The usage of biogas and of natural gas to supply the WWTP energy demand as obtained from the optimal dispatch model is reported in *Table 3* and *Figure 3* for all the scenarios. It is worth noting that the biogas availability is not sufficient to supply the energy demand of the system and natural gas needs to be bought in all the cases. In scenario (A), due to the highest thermal efficiency in the fuel combustion, the boiler imports less natural gas compared to alternative technologies which do not imply advanced sludge handling (A — C). The MGT (scenario B) has better thermal performance compared to co-generation alternatives and shows by far the largest reliance on imported gas as this is used either in the boiler (591,385 kWh) or in the CHP unit (1,408,238 kWh) in addition to the biogas. The SOFC cases, C and its UK equivalent F, show a high reliance on natural gas to fulfil the thermal load as biogas is preferably used for co-generation rather than pure combustion in the boiler. Cases D and E display low dependence on natural gas as thermal loads are remarkably reduced by the introduction of pre-thickening technologies.

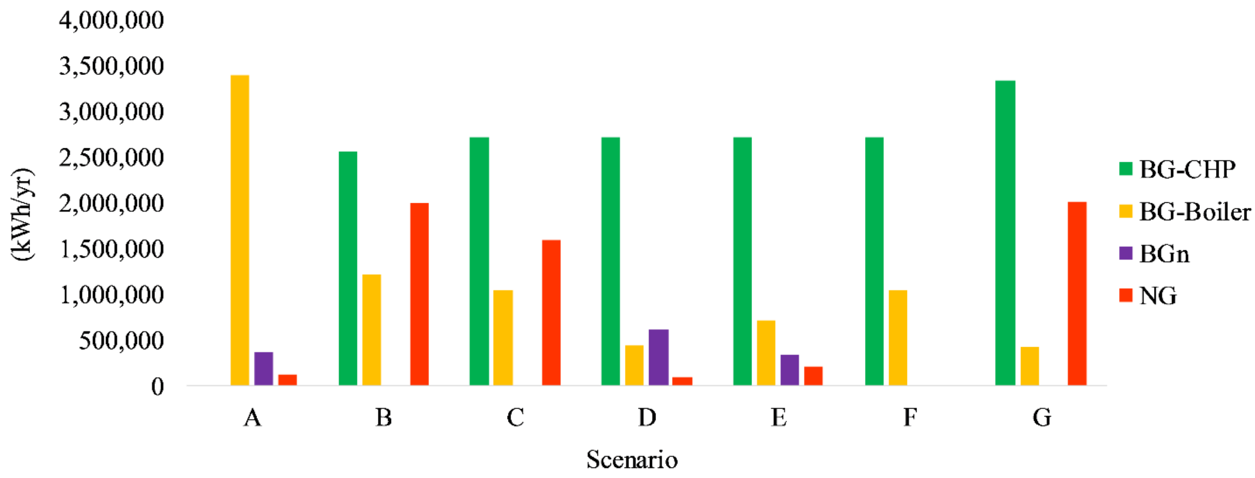
In all the SOFC-related scenarios, the optimal operating strategy which corresponds to the minimum system cost defines a full-year operation with no stop events. In every hour of operation, the biogas flow available is optimally distributed among storage, SOFCs and boiler. The hour-by-hour profiles of heat and electricity generations for scenario C over a year are provided in *Appendix C: hourly profiles of major variables*.

Comparing the heat and electricity trends with the biogas flow as produced by the digester, also reported in *Appendix C: hourly profiles of major variables*, it appears that, although in summer (between 5,000 – 6,000 hours of operation) the inlet biogas is low, it is all fed into the SOFCs. In the same time window, the boiler burns natural gas only.

Table 3: Optimal commitment strategy: biogas flows (kWh/yr) into the CHP system (BG-CHP), to the boiler (BG-Boiler), to flaring (BGn) and natural gas import (NG) in scenarios A, B, C, D, E, F, G for a year of operation

Scenario	BG-CHP (kWh/yr)	BG-Boiler (kWh/yr)	BGn (kWh/yr)	NG (kWh/yr)
A	0	3,394,545	371,604	120,273
B	2,551,132	1,215,469	0	1,999,623
C	2,716,624	1,049,746	0	1,591,278
D	2,716,158	434,131	612,033	90,322
E	2,716,337	710,448	337,270	212,267
F	2,716,624	1,049,746	0	1,591,27
G	3,335,887	429,411	0	2,011,174

The overall energy and environmental performance of the system in terms of electricity, thermal balance and CO_2 emissions of the plant are present in *Table 4* for the proposed case studies. According to results shown in *Table 4*, in scenario B almost half of the thermal load is met with the CHP system (thermal self-sufficiency equal to 48.6 %), while the electrical self-sufficiency only goes up to 15.5 %. In scenarios C and F the thermal self-sufficiency rate is 24.9 %, while the electrical self-sufficiency rate is 25.6 %. With the installation of one additional cell (scenario G), the electric ratio would increase up to 31.3 % while the thermal self-sufficiency up to 30.6 %.



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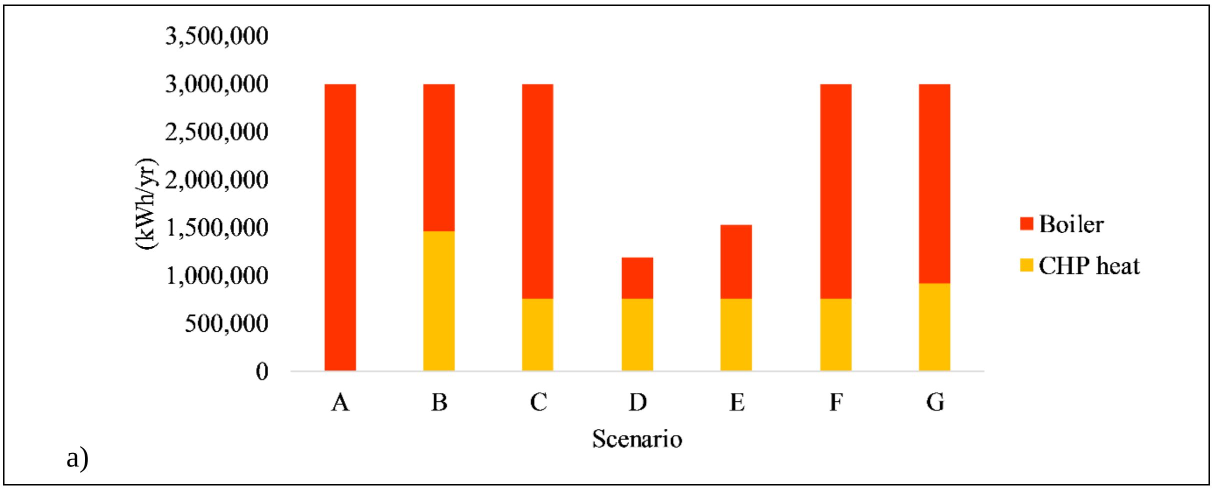
A dramatic improvement of the overall system performance is obtained when advanced technologies are used for sludge handling. The ratio between the on-site generated thermal energy and the thermal load increases up to 62.5 % and 48.6 % in cases D and E; the ratio between generated electricity generated and the demand remains equal to 26.5 %. The advantage of pre-thickening systems is to reduce the water content of sludge so that less pre-heating thermal duty is required prior to feeding the sludge to the digester. In the analysed WWTP (i.e. scenario C and F), the sludge is currently pre-thickened only by gravity settles that yield a total suspended solid (TSS) of about 1.9 wt. %. By means of centrifugal pre-thickening and dynamic pre-thickening the TSS increases to 6 — 8 and 4 — 7 wt. %, respectively. TSS values above 8 % wt. of TSS are not really feasible as sludge agitation inside the digester becomes problematic.



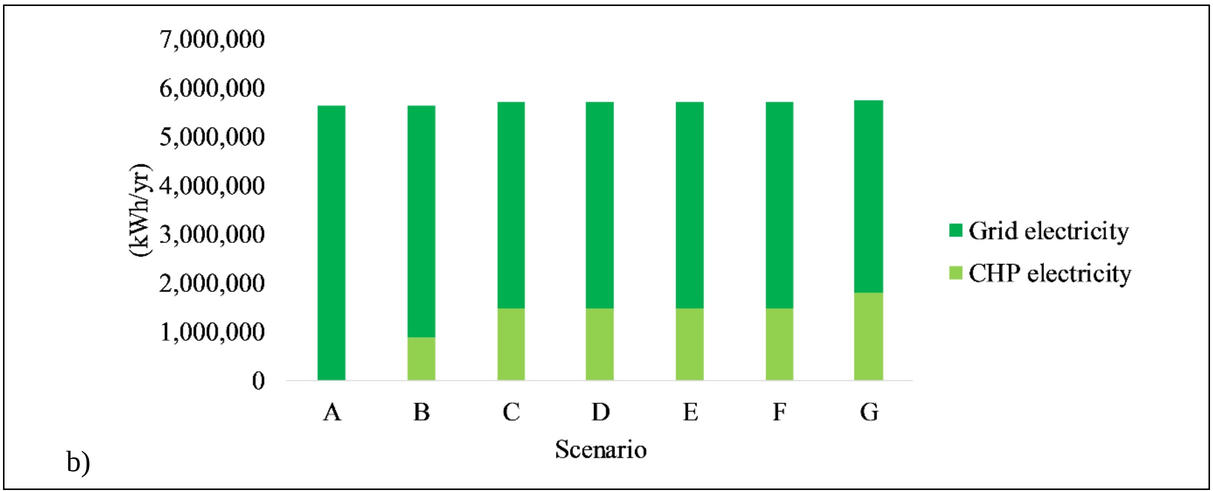


Figure 4. Optimal commitment strategy: share of thermal energy production from CHP system and boiler (Figure 4a) and share of electrical energy production from CHP and grid (Figure 4b),

The equivalent annual cost for the system used in the techno-economic assessment, was calculated as follows. It includes the equivalent annual cost due to initial capital investment as well as future replacement of equipment units, fixed operating and maintenance (O&M) costs due to energy supply and clean-up (where present) system maintenance, running operating costs due to fuel consumption and carbon cost. Fuel costs include all the expenses due to the energy imported into the system; as such they account for both natural gas and electricity bought by the WWTP.

Table 4: Optimal commitment strategy: thermal energy produced from the CHP system (CHP heat, kWh/yr), thermal load of the WWTP (Th. load, kWh/yr), emissions from the WWTP (kgCO_2/yr), electricity bought from the grid (Grid electricity, kWh/yr) and electricity demand (El. Demand, kWh/yr) in scenarios A, B, C, D, E, F, G for a year of operation.}

Case	**CHP heat (kWh/yr)**	**Th. Load (kWh/yr)**	**Emissions (kgCO_2/yr)**	**CHP electricity (kWh/yr)**	**Grid electricity (kWh/yr)**	**El. Demand (kWh/yr)**
A	0	2,987,595	2,662,732	0	5,637,685	5,637,685
B	1,451,769	2,987,595	2,634,704	871,062	4,766,623	5,637,685
C	742,725	2,987,595	2,307,905	1,461,544	4,244,588	5,706,132
D	742,598	1,188,383	2,006,443	1,461,293	4,244,828	5,706,121
E	742,646	1,526,954	2,094,083	1,461,544	4,244,588	5,706,132
F	742,725	2,987,595	2,337,617	1,461,389	4,244,736	5,706,125
G	913,098	2,987,595	2,245,437	1,791,494	3,929,871	5,721,365

Table 5 and *Figure 5* collect the results of the techno-economic appraisal assuming a carbon neutral policy with no carbon price in force. *Table 5* shows that scenarios C — F and G display the lowest operating costs. It is apparent that SOFCs can relieve the WWTP running operating costs due to fuel consumption (i.e. natural gas and electricity bought from the grid). However, fixed costs due to maintenance of both SOFCs and the clean-up system are higher compared to alternative technologies. Capital costs still represent a barrier to commercialisation as important as the need for replacing the stack. It worth noting that scenario F displays a more profitable business case than its Italian equivalent (scenario C), being characterised by lower energy costs, with 11 % and 40 % of reduction on electricity and natural gas prices[2].

Costs associated to start/stop events are always zero except for scenario G, where cells are constrained by the low biogas availability in summer.

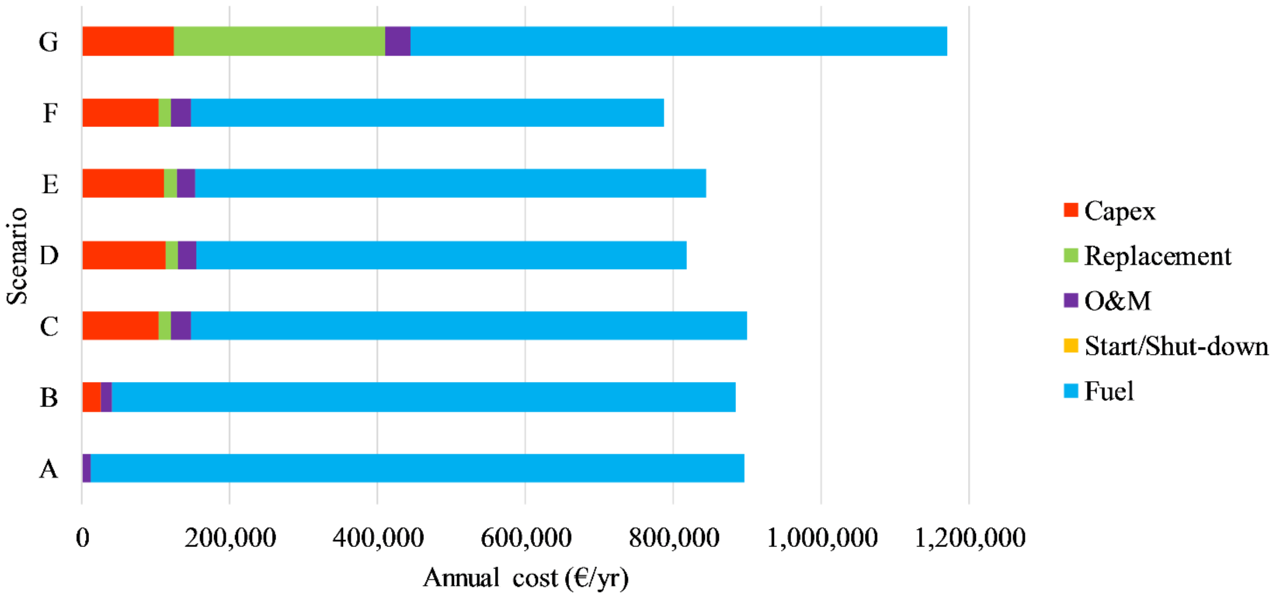


Figure 5. Optimal commitment strategy: annual costs. The figure reports: equivalent annual capital cost (Capex, €/yr), fixed operating and maintenance costs (O&M, €/yr), costs due to fuel consumption (Fuel, €/yr) (i.e. natural gas and electricity bought from grid), costs due to carbon price (Carbon, €/yr), equivalent annual costs due to replacement of aged equipment units (Replacement, €/yr), total annual costs (Total, €/yr), in scenarios A, B, C, D, E, F, G.

[2] An exchange rate from GBP to € equal to 1.38 was used as per currency quotations in January 2016.

Table 5: Optimal commitment strategy: annual costs. The table reports: equivalent annual capital cost (Capex, €/yr), fixed operating and maintenance costs (O&M, €/yr), costs due to fuel consumption (Fuel, €/yr) (i.e. natural gas and electricity bought from grid), costs due to carbon price (Carbon, €/yr), equivalent annual costs due to replacement of aged equipment units (Replacement, €/yr), total annual costs (Total, €/yr), in scenarios A, B, C, D, E, F, G.

Scenario	**Capex (€/yr)**	**O&M (€/yr)**	**Fuel (€/yr)**	**Start/Shut-down (€/yr)**	**Replacement (€/yr)**	**Total (€/yr)**
A	0	11,308	884,040	0	0	895,348
B	25,365	15,817	843,746	0	0	884,929
C	103,442	25,885	752,342	0	17,276	898,945
D	112,378	25,885	662,866	0	17,276	818,405
E	110,212	25,885	691,354	0	17,276	844,727
F	103,442	25,885	641,575	0	17,276	788,179
G	124,203	34,514	726,418	190	285,204	909,720

Technological learning

Technological learning pathways have been modelled assuming a cost reduction in the investment in the stacks, in the replacement of the modules, in the investment in clean-up as well as in the maintenance. In the short term (by 2020), annualised capex would decrease as well as stack replacement cost would decrease by more than 50 % compared to the current state of SOFC development, as shown in *Table 7* according to the trends in cost reduction displayed in *[4]*. This would make the SOFC technology advantageous in a carbon neutral policy as shown in *Figure 6*.

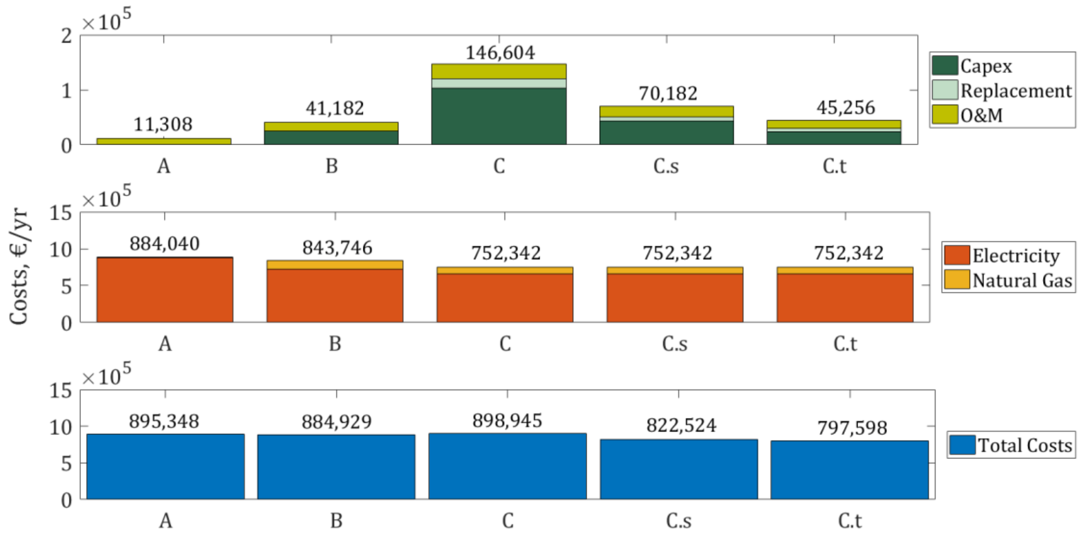


Figure 6: Impact of technology learning. A refers to an energy supply system based on boiler; B considers an energy supply system based on an MGT; C involves an energy supply system using an SOFC-based CHP; Cs and Ct represent an evolution of C where costs follow the trajectories for the short term and target scenarios of technological learning and technology diffusion as in [4].

Sensitivity on economic input

In order to understand the kind of policy which could make an impact on the SOFC commercialisation, economic input were varied to understand their relevance on the feasibility of the technology. Starting from the base case scenario A, B, C sensitivity analyses were performed varying the economic factors as outlined in *Table 6*. It is worth noting that the base case scenario (A, B, C) do not include any carbon price policy. This has been introduced in instance 1 of the sensitivity analysis, where a carbon price equal to 0.022 €/kgCO_2 was used.

Table 6: Assumptions on key economic input assessed in the sensitivity analysis

Instance	1	2	3	4	5	6
carbon price, €/kgCO_2	0.022	0.132				
natural gas price, €/kWh			0.03	0.078		
electricity price variation, %					-30	+30

Figure 7 shows the outcomes of the sensitivity analysis. From the results, scenario A appears rather insensitive to natural gas price variations, while impacts of electricity prices as well as of a carbon

policy based on carbon cost would be far more significant. The MGT increases considerably the natural gas consumption fed to the CHP system (rather than to the supplementary boiler) at low gas price (instance B.3) as well as high electricity price (B.6). On the contrary, high natural gas price (instance B.4), and low electricity price (instance B.5), would promote the use of biogas in the supplementary boiler. From the results, it also appears that commercial opportunities for the SOFC commercialisation would become more tangible in a context where decarbonisation policies were put in place. Due to the lower CO_2 emissions, when a carbon price is fixed (instance C.2), an SOFC-based CHP system would be more economical than all the remaining technological options and the equivalent annual cost would be about 3.5 % lower than current configuration based on boiler (scenario A). High gas prices (instance 3) would make co-generation about 3.3 % more expensive than boiler as it relies more on the use of natural gas. High electricity prices (instance 6) would make co-generation based on MGT or SOFC more convenient options, as they would display an annual equivalent cost 5 % lower than the boiler.

Interestingly, SOFCs would always outperform in terms of running operating costs, showing the lowest costs for energy import (i.e. natural gas, electricity) and emissions costs in all sensitivity instances. Because of their higher reliance on natural gas, low gas prices (instance 3) would favour co-generation, MGT in particular. A market with very cheap electricity supply (instance 5 for both case B and C), would make technologies based on boiler more economical than co-generation: MGT and SOFC would become respectively 2 % and 11 % more expensive. However, this appears a rather unlikely perspective in energy systems where decarbonisation policies are primarily targeting the electricity supply from the grid.

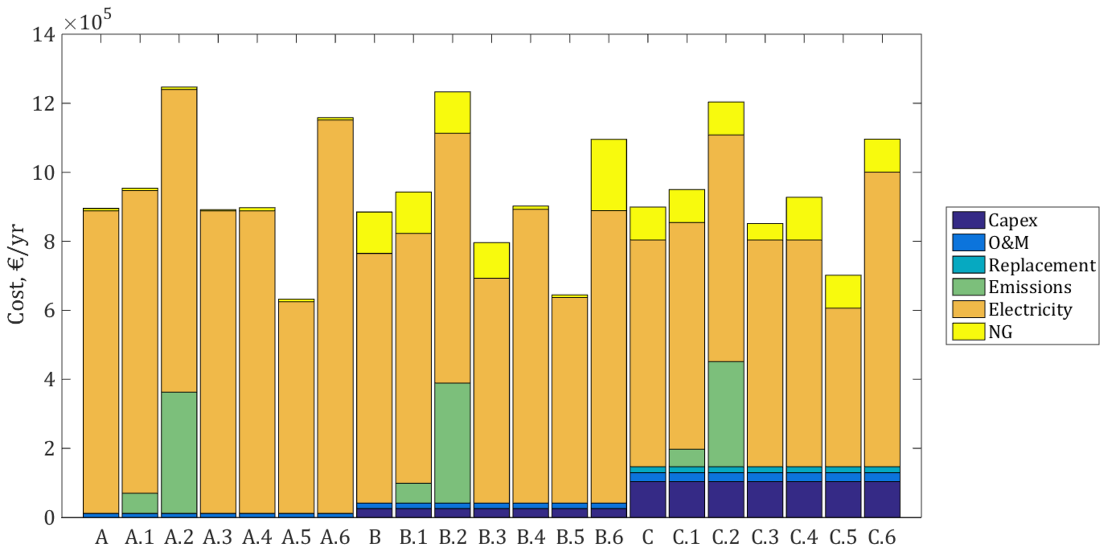


Figure 7: Sensitivity analysis. A refers to an energy supply system based on boiler; B considers an energy supply system based on an MGT; C involves an energy supply system using an SOFC-based CHP. Numbers represent the sensitivity analyses performed on carbon price (1 -- 2), natural gas price (3 -- 4) and on electricity price (5 -- 6), as shown in Table 6.

6. **Concluding remarks**

A mathematical MILP modelling framework has been presented for the minimum cost unit commitment of a WWTP retrofitted with a sub-MW SOFC CHP system. Constraints were also included to represent SOFC dynamics, such as minimum up-time, ramp limits, and start-up/shut down costs. A techno-economic appraisal was built onto the optimal operating strategy for the system. A series of scenarios were delivered to build up a framework for comparative performance assessment of the technology. The scenarios included: the current system configuration, a hypothetical micro gas turbine CHP system, a 3-module SOFC-based CHP system, variations of the SOFC case (sludge centrifugal thickening before the digester; sludge dynamic thickening before the digester) and a simulation of a different market (a 3-module SOFC-based CHP system operating in the UK market). A sensitivity analysis was also carried out on economic inputs, such as carbon, natural gas and electricity price. The modelled scenarios were assessed in terms of equivalent annual costs, including investments as well as operating costs.

The results of the optimal dispatch for the 3-module SOFC-based CHP show that the wastewater treatment plant achieves thermal self-sufficiency rate of 24.9 %, while the electrical self-sufficiency rate is 25.6 %. It is worth noting that the existing WWTP has itself room for better energy integration strategies which would improve the overall system performance.

SOFC proves to be the winning technology in reducing dependence on fossil resources and impact on climate change. Current stage of development of this technology involves high investment costs and frequent replacements of the stack, which still represents a considerable share of the cost of the module. Assuming the technological learning pathways reported in *[4]*, beyond 2020 the investment costs for SOFCs installations are expected to fall to 2,077 €/kW, while stack lifetime may increase up to 7 years.

The results from the sensitivity analysis highlight good potential for future applications of SOFCs in the broader context of decarbonisation of energy systems. The introduction of carbon prices or high electricity prices could support the commercialisation of this technology making it competitive with all alternative options considered.

7. **Future work**

The work presented in this deliverable will be the object of further analysis during the DEMOSOFC project. In WP6 of project, business models for the integration biogas SOFC plan will be provided. The techno-economic model delivered in this report will be refined and extended to include:

- a comparison with Internal Combustion Engines;
- a more detailed assessment about the impact of the WWTP energy profiles (i.e., thermal and electric demands) on the economic performance of the SOFC (e.g., scenario D and E will be investigated in more detail, also assuming technology learning for both SOFC and clean-up units);
- the case of a higher efficiency SOFC (up to 60% of net AC electric efficiency of the module).

Furthermore, the comments addressed by the Project Officer have been implemented in the following revised version of the deliverable and are presented below.

i) *At this stage most of the costs used are based on estimates. Please clarify where and how you are expecting to update the analysis undertaken as long as the project advances and more accurate values can be provided.*

Deliverable D2.5 has been partially revised in order to provide the most updated calculations. The economic analysis is an activity that will be developed all along the 5 years of the project.

We have provided a first "state-of-the-art" cost-benefit analysis at the beginning of the project (Deliverable D2.5 Cost/benefit analysis of the system, on M6) mainly using the data provided by the provider of the SOFC modules (CONVION) and the trends indicated in the most important study of the sector (Roland Berger Strategy Consultant, "Advancing Europe's energy systems: Stationary fuel cells in distributed generation", 2015).

We are developing our economic analysis, and we expect to have a more complete idea of the cost of the site preparation at the end of the installation step (April 2017), so that we could provide some precise indications on the site preparation to the stakeholders in the next communications (conferences, workshops, papers), followed with further analysis about how these costs can be reduced in the near and medium future.

Also, the SOFC manufacturer (CONVION) will experience an evolution of its production volumes and processes, providing an expectation of cost reduction for its module.

All these analyses will be collected and organized in a structured way in the WP6, developed in the second part of the project (M36-M60). Then, the following Deliverables related to the economic analysis are already scheduled:

- D6.1 SOFC-based CHP market potential analysis, M54
- D6.2 DEMOSOFC value chain analysis, M60

ii) *The proposed project expects to bring the technology demonstrated from TRL 7 to 9. Could you please clarify where in the project (deliverables?) the underpinning business models will be presented?*

As described above, the economic analysis and the business models will be collected and organized in a structured way in the WP6, developed in the second part of the project (M36-M60). Then, the following Deliverables related to the economic analysis are already scheduled:

- D6.1 SOFC-based CHP market potential analysis, M54
- D6.2 DEMOSOFC value chain analysis, M60

In particular, the Task T6.2: DEMOSOFC value chain analysis (Task leader: IC - Participants: POLITO, CONVION, SMAT, VTT - Start: M48 - End: M60) will discuss this. During the years of operation of the biogas fed integrated SOFC system, it is expected that a great deal of experience in interacting with the relevant supply chain will be gained. This task will synthesize this experience and produce an analysis of the supply chain opportunities and bottlenecks, with recommendations for actions to streamline the supply chain and improve knowledge and availability of critical components.

iii) *In order to better understand the conclusions reached, the conclusions section could be retitled to "sensitivity analysis". Instead the conclusion section should include the key messages emerging from the analysis and modelling undertaken. Could you please comment on this.*

We agree on that. We have modified the Deliverable D2.5 according to this suggestion, and we have uploaded the new version of the Deliverable D2.5 in the Participant Portal.

iv) *This deliverable contains useful information but the assumptions underpinning the modelling and hence results presented and the economical parameters shown are not always clear. For instance, does the "so-called" costs refer to net present cost throughout the lifetime of the project? What discount rate have been used? etc.*

If we analyze the "SOFC scenario" in the economic analysis, the cost items included are:

- SOFC INVESTMENT COST (CAPEX) 7000 €/kW
- SOFC MAINTENANCE COST (OPEX) 2 % of SOFC Investment cost

- SOFC REPLACEMENT COST 3,500 €/kW
- CLEAN-UP INVESTMENT COST (CAPEX) 917 €/kW
- CLEAN-UP OPERATION COST (OPEX) 76 €/kW
- NATURAL GAS COST 0.06 €/kWh
- ELECTRICITY COST Hourly profile (0.157 €/kWh on average)
- UNIT SHUT-DOWN COSTS 0.054 €/kWh
- UNIT START-UP COST Electricity price * 7.6 kWh/h of a start-up event

The different cost items are classified as:

- Discounted costs (with an interest rate of 10%) considered in a lifetime of 20 years
- Non-discounted costs

The cost items included in the two classifications are, for the "SOFC scenario":

Discounted costs (interest rate 10 %)	Non-discounted costs
1) SOFC Investment: 1,224,300 €	1) Annual NG costs: 49,953.5 €/y
2) Total investment: 3,068,742 €	2) Annual electricity costs: 681,073.2 €/y
3) Operation: 6,705,158.2 €	3) Annual carbon costs: 56,513.0 €/y
4) Replacement: 1,491,125.7 €	4) Annual shut-down+start-up costs: 45.8 €/y
5) Maintenance: 522,518.6 €	

8. Bibliography

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[8] DECC, “Prices of fuels purchased by non-domestic consumers in the United Kingdom excluding/including CCL,” 2016.

[9] IPCC, “2006 IPCC Guidelines for National Greenhouse Gas Inventories,” Intergovernmental panel on climate change, 2006.

[10] URS Corporation, “Greenhouse Gas Emission Factor Review - Final Technical Memorandum,” Edison Mission Energy, 2003.

[11] Argonne National Laboratory, “Gas Clean-up for fuel cell applications workshop,” 2014.

9. Appendix A: symbols

Acronyms

AC	alternating current
CHP	combined heat and power
EP	equivalent person
GT	gas turbine
MGT	micro gas turbine
ICE	internal combustion engine
MILP	mixed integer linear programming
RDD&D	research, development, demonstration, and deployment
SOFC	solid-oxide fuel cell
TSS	total suspended solids
WWTP	wastewater treatment plant

Sets

$f \in F$	fuel cells, $F = \{f1, ..., fn\}$
$r \in R$	regimes, $R = \{r1, r2\}$
$t, tt \in T$	periods, $T = \{t1, \dots , t8760\}$
$dot \subset T$	minimum hours for shut-down event, $dot_t = \{t+1, \dots , t+td-1\}$
$upt \subset T$	minimum hours for start-up event, $upt_t = \{t+1, \dots , t+tup-1\}$
$u \subset U$	set of clean-up utilities, $U = \{u1, \dots , un\}$

Parameters

BCap	boiler capacity, kWh
BGi_t	BG flow inlet, kWh

BGSabs	BG absorbed per start up event, kWh
BGDabs	BG absorbed per shut down event, kWh
DTL_t	system thermal load per time t, kWh
Ed_t	WWTP electricity demand at time t, kWh
η_b	boiler thermal efficiency,
η_{fel}^{r}	fuel cell electrical efficiency per regime
η_{fth}^{r}	fuel cell thermal efficiency per regime
cp	carbon price, € per $kgCO_2$
GHL	gas holder lower volume limit, kWh
GHU	gas holder upper volume limit, kWh
rup	ramp modulation, kWh
ee	electricity emission factor, $kgCO_2$ per kWh
ep_t	electricity price at time t, € per kWh
ge	natural gas emission factor, $kgCO_2$ per kWh
gp_t	natural gas price at time t, € per kWh
n	number of SOFC modules
Pnom	fuel cell nameplate capacity, kWh
PRU_r	maximum electric output per fuel cell regime r, kWh
PRL_r	minimum electric output per fuel cell regime r, kWh
td	fuel cell minimum down time, hours
tup	fuel cell minimum up time, hours
UEC_u	unit energy consumption of utility u
UMC	maintenance cost per fuel cell, € per kWh
UOC	clean-up cost per fuel cell, € per kWh
PSUabs	average power absorbed per start up event, kW
PSDabs	average power absorbed per shut down event, kW

Decision variables

BGb_t	BG fuelled into SOFC at time t, kWh
$BGD_{t,f}$	BG flow absorbed for shut-down at time t of cell f, kWh
BGn_t	BG flow not exploited at time t, kWh
$BGS_{t,f}$	BG flow absorbed for start-up at time t of cell f, kWh
Ei_t	electricity bought from grid at time t, kWh
GH_t	gas holder level at time t, kWh
NGb_t	natural gas fuelled into boiler at time t, kWh
$PSD_{t,f}$	electricity absorbed for shut down of cell f at time t, kWh
$PSS_{t,f}$	electricity absorbed at start-up of cell f at time t, kWh
$\upsilon_{t,f}$	binary equal to 0 if generator f at time t is switched off, to 1 if switched on
$\chi_{t,r,f}$	binary equal to 1 if at time t generator f operates at regime r, 0 if switched off
$X_{t,r,f}$	electrical output of cell f per regime r and time t, kWh

Objective function variables

TC	total annual cost of CHP system, € per year

10. Appendix B: Input data for modelling the SOFCs

Table 7: a. Techno-economic characteristics of the SOFC system in the current, short-term and target scenario of technological development; b. Techno-economic characteristics of the clean-up system

SOFC technical input [6]	unit	current	short-term	target
Module lifetime	years	20	20	20
Stack lifetime	years	5	6	7
Net AC Electric Capacity	kW	58.3	58.3	58.3
Number of modules installed	number	3	3	3
Minimum up-time	hours	24	24	24
Minimum down-time	hours	24	24	24
Maximum ramp up	kWh/h	40	40	40
Power for start-up	kWh/h	40	40	40
Biogas for start up	kWh/h	17.09	17.09	17.09
Power for shut down	kWh/h	5	5	5
Biogas for shut down	kWh/h	17.09	17.09	17.09

Full load operation [6]	unit	current	short-term	target
Ratio of biogas	%	50 — 100	50 — 100	50 — 100
Thermal efficiency	%	27	27	27
Electrical efficiency	%	53.8	53.8	53.8

Partial load operation [6]	unit	current	short-term	target
Ratio of biogas	%	30 — 50	30 — 50	30 — 50
Thermal efficiency	%	31.5	31.5	31.5
Electrical efficiency	%	41.2	41.2	41.2

SOFC Costs [4]*	unit	current	short-term	target
Module Capex	€/kW	8,303	3,346	2,077
Stack Replacement	€/kW	1,223	540	478
Maintenance	€/kW/yr	72	54	44

a)

Clean-up system [11]**	unit	current	short-term	target

Capex	€/kW	917	459	183
Maintenance	€/kW/yr	76	57	38

* The SOFC capital and maintenance costs have been taken from FCH-JU [4]. More specifically, we named current, short term and target scenarios those scenarios that refer the 50 KW CHP module having a cumulative production of 100, 1,000 and 10,000 units (the cumulative production refers to units manufactured by the same company).

** The clean-up capital and maintenance costs have been taken from the proceeding of an international workshop organized by the Argonne National Laboratory and the US Department of Energy (DOE) [11]. During the workshop, the different technological options available for the biogas clean-up have been reviewed and discussed. Current and both short- and long-term cost scenarios have been also assessed, which are summarized in the Table.

11. Appendix C: hourly profiles of major variables

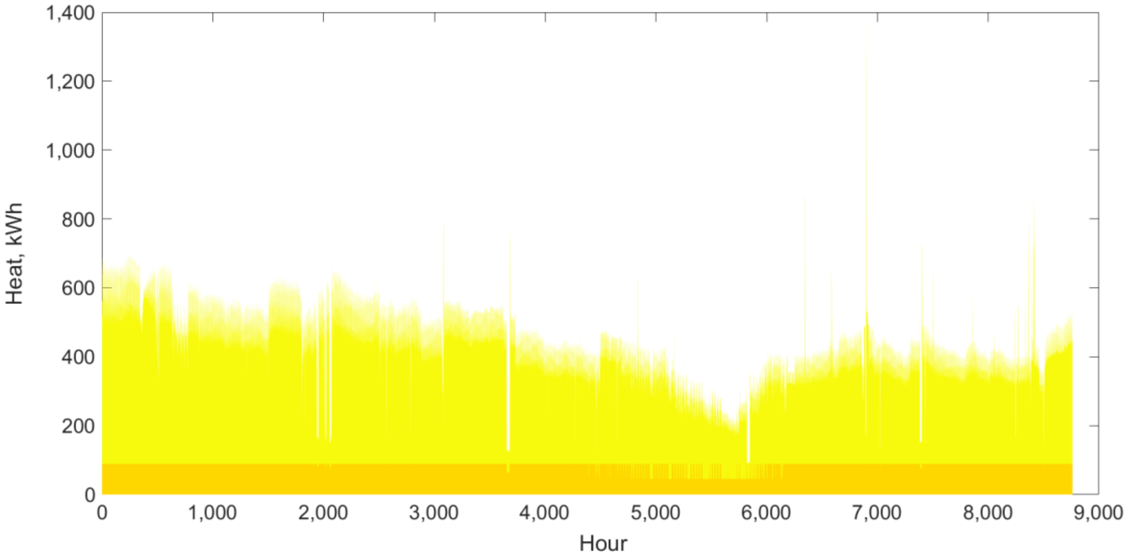

Figure 8: Heat supply to WWTP on hourly basis: light yellow represents heat provided by the boiler; dark yellow indicates heat provided by SOFCs (kWh)

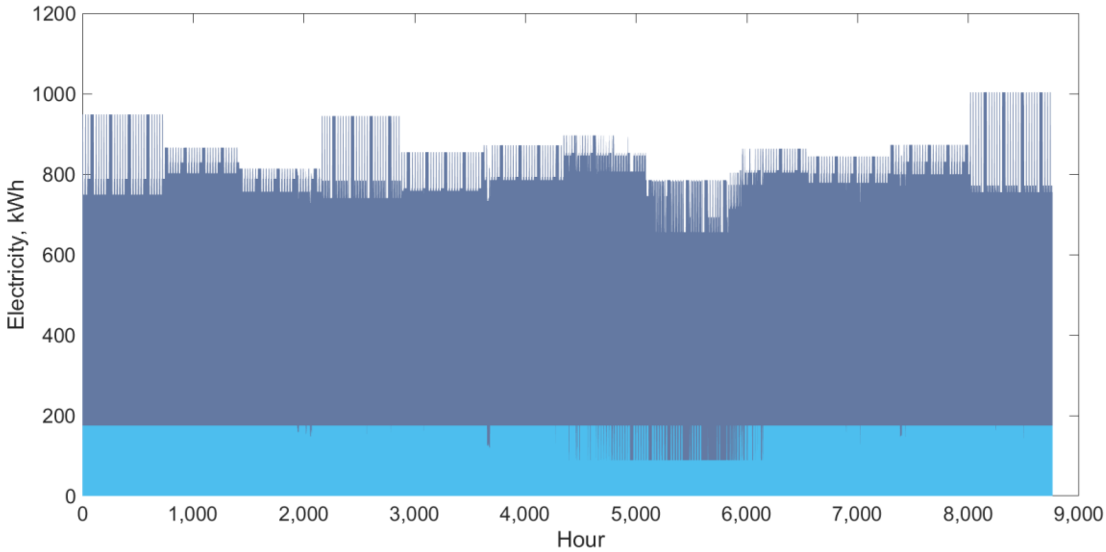

Figure 9: Electricity supply to WWTP on hourly basis: dark blue represents electricity imported by the grid; light blue indicates electricity provided by SOFCs (kWh)

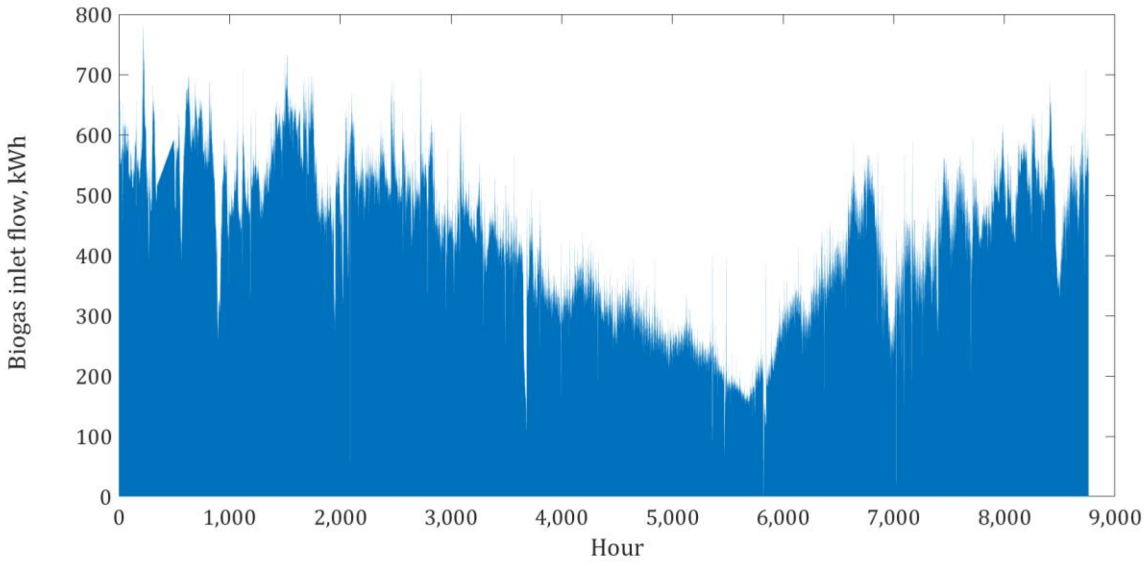

Figure 10: Biogas flow from the digester on hourly basis (kWh) [6]

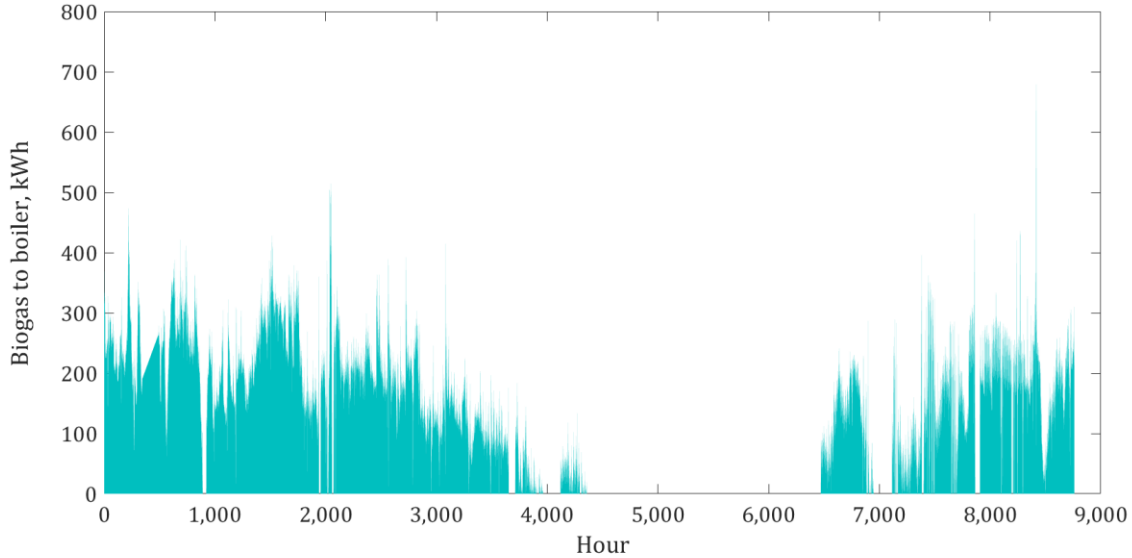

Figure 11: Hourly profile of biogas rate to boiler (kWh)

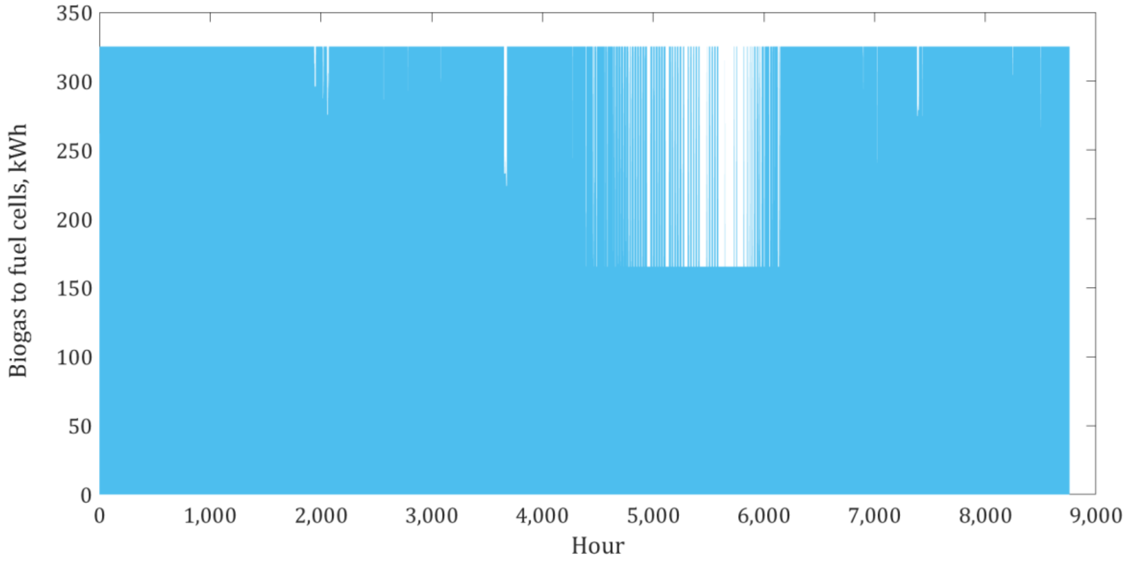

Figure 12: Hourly profile of biogas rate to SOFCs (kWh)

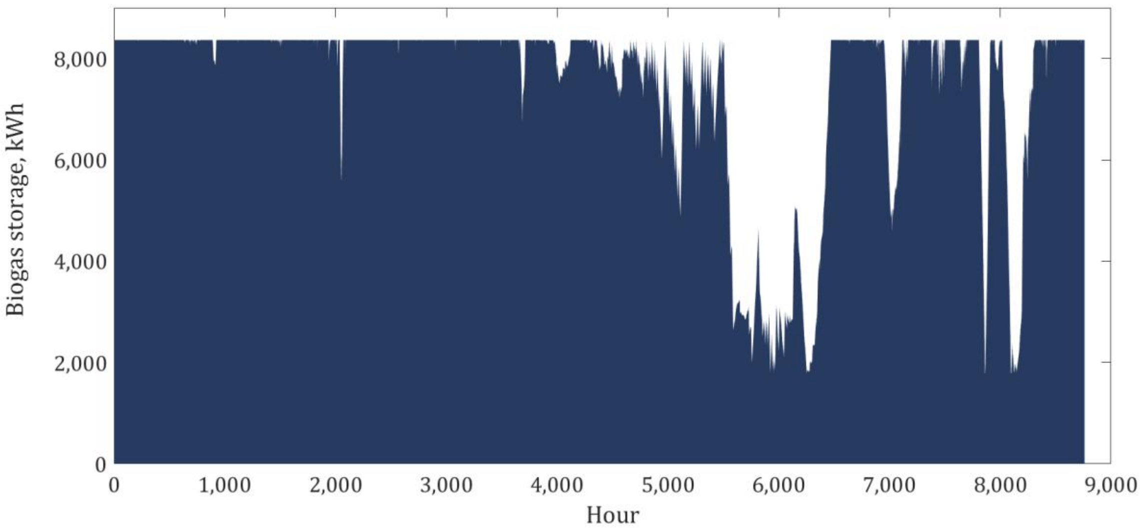

Figure 13: Hourly profile of biogas storage level (kWh)

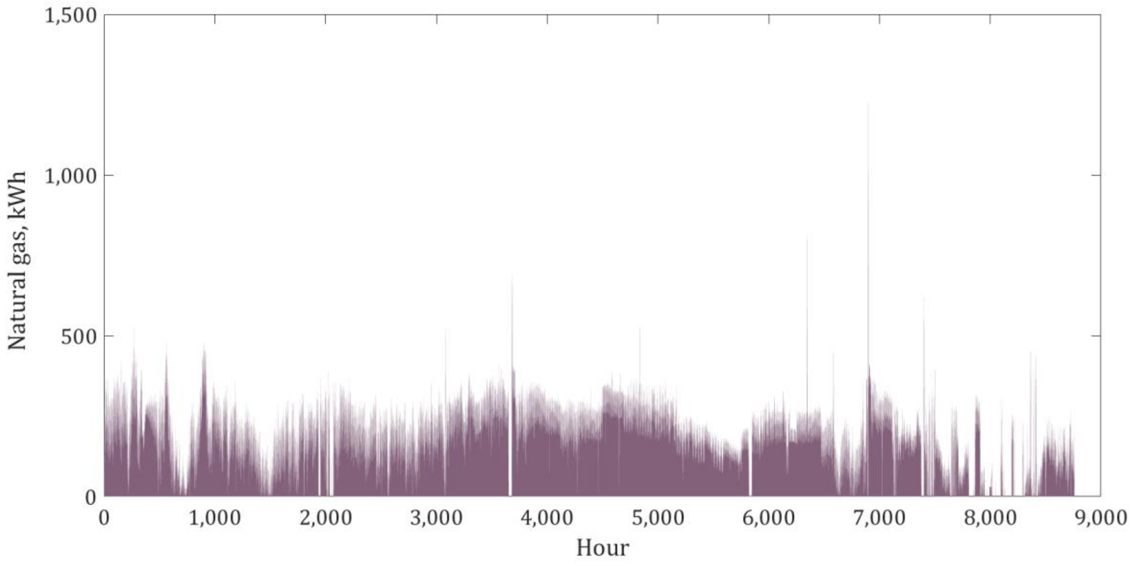

Figure 14: Hourly profile of natural gas bought from grid (kWh)

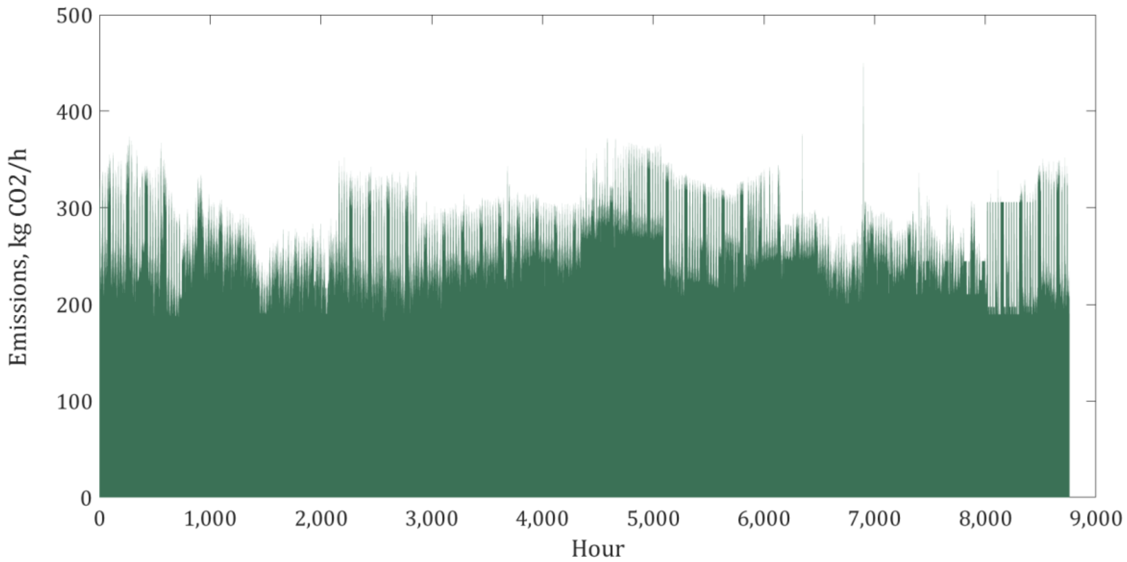

Figure 15: Hourly profile of WWTP emissions (kg CO_2/h)