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Gas Turbine Cogeneration Groups Flexibility to Classical and Alternative Gaseous Fuels Combustion

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Additional information is available at the end of the chapter

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1. Introduction

The gas turbine installations represent one of the most dynamic fields related to the applicability area and total installed power. The gas turbines have been developed particularly as aviation engines but they find their applicability in many areas, one of which being simultaneously obtaining electric and thermal energy in gas turbine cogeneration plants. The gas turbine cogeneration plants may be classified based on the constructive technology of the gas turbine in [1]: aeroderivative gas turbines plants (up to 10 MW); industrial gas turbines plants, specifically designed for obtaining energy (from 10 up to hundreds MW). An aviation gas turbine with expired flying resource is still functional due to the fact that the flight time is limited as a consequence of the specific safety normative requirements. Therefore the aeroderivative gas turbine is defined as a gas turbine, derived from an aviation gas turbine, dedicated to ground applications. According to the initial destination, these gas turbines have been designed for maximum efficiency considering the limited fuel quantity available for an aircraft flying large distances. The basic idea in developing the aeroderivative gas turbine has been to transfer all the scientific and technologic knowledge ensuring a high degree of energy utilization (design concepts, materials, technologies, etc.) from aviation to ground [2]. Therefore the obtained gas turbines are lighter, with smaller size, increased reliability, reduced maintenance costs and high efficiency. The remaining resource for ground applications is proportional with the flight resource, being able to reach up to 30,000 hours considering the lower operating regimes. From the point of view of the actual application, the free power turbine groups are the most recommended [3]. Unlike the aeroderivative turbine power units, the industrial power units are built by the original producer

with the necessary changes for actual industrial application. The development of aeroderivative and industrial gas turbines has been affected by the progress of the aviation gas turbines in military and civilian fields. Many aeroderivative gas turbines ensure compression rates of 30:1 [4]. The industrial gas turbines are cumbersome but they are more adaptable for long running and allow longer periods between maintenance controls. The base fuel for gas turbine cogeneration groups is the natural gas (with a possible liquid fuel as alternative) but the diversification of the gas turbines users and the increase in fuels price has pushed the large producers to consider alternative solutions. Nowadays the most utilized fuels in gaseous turbines are the liquid and gas ones (classic and alternative). The high temperature of the exhausted gases, approximately 590 °C on some gas turbines, allows the valorization of the heat resulted in a heat recovery steam generator. Due to the fact that the oxygen concentration in the exhausted gases is 11-16% (volume), a supplementary fuel burning may be applied (afterburning) in order to increase the steam flow rate, compared to the case of the heat recovery steam generator [5]. The afterburning leads to an increase in flexibility and global efficiency of the cogeneration group, allowing the possibility to burn a large variety of fuels, both classic and alternative. Nitrogen oxides usually represent the main source of emissions from gas turbines. The NO_x emissions produced by the afterburning installation of the cogeneration group are different according to the system, but they are usually small and in some cases the installation even contributes to their reduction [6]. The usual methods for NO_x emissions reduction, water or steam injection for flame temperature decrease, affect the gas turbine performances, particularly to high operating regimes, leading to CO emissions increase. It must be noted that the load of the gas turbine also affects the emissions, the gas turbine being designed to operate at high loads. The general theme of the chapter is given by the technological aspects that must be considered when aiming to design a gas turbine cogeneration plant flexible from the points of view of the utilized fuel and the qualitative and quantitative results concerning some classic and alternative gas fuels. Based on the specific literature in the field and the experience of National Research and Development Institute for Gas Turbines COMOTI Bucharest, there are approached theoretic and experimental researches concerning the utilization of natural gas, as classic fuel, and respectively dimethylether (DME), biogas (landfill gas) and syngas, as alternative fuels, in gas turbine cogeneration groups, the interference between flexibility and emissions. It is particularly analysed the issue of reutilization of aviation gas turbines in industrial purposes by their conversion from liquid fuel to gas fuels operation. There is further presented the actual method of conversion for an aviation gas turbine in order to be used in cogeneration groups.

2. The aeroderivative gas turbine – A solution for gas turbine cogenerative groups flexibility on gas fuels

The flexibility of the gas turbine cogeneration plants implies reaching an important number of requirements: operating on classic and alternative fuels; capability of fast start; capability to pass easily from full load to partial loads and back; maintaining the efficiency at full load and partial loads; maintaining the emission to a low level even when operating on partial

loads. Internationally, many companies with top performance in aviation gas turbines are involved in aeroderivative programs in response to market demands for energy producing installations. The best known among these are: Rolls-Royce, Pratt & Whitney, General Electric, Motor Sich, Turbomeca, MTU, etc. Rolls-Royce has developed the RB 211-H63 gas turbine starting from the aviation RB 211 which, through novel constructive and technologic transformations has been pushed to efficiency up to 41.5%. A 38 MW version will be available in 2013 with the possibility of upgrade to 50 MW in future years [7]. Many gas turbine producers aim to reach the full load in ten minutes from the start. A Japanese project of Mitsubishi Heavy Industries Ltd. (MHI) aims to manufacture a gas turbine operating at 1700 °C inlet temperature and 62 % efficiency. Pratt & Whitney, starting from the PW 100 turboprop, have developed the ST aeroderivative gas turbine family (ST 18, ST 40). The researches conducted at National Research and Development Institute for Gas Turbines COMOTI Bucharest have allowed obtaining aeroderivative gas turbines in the 20 – 2,000 kW range, through valorisation of the aviation gas turbines with exhausted flight resource, obsolete or damaged. Therefore the AI 20 GM (figure 1, right) aeroderivative turboshaft, operating on natural gas, is based on the AI 20 turboprop (figure 1, left). The AI 20 GM is used in power groups driving the backup compressors in the natural gas pumping stations on the main line at SC TRANSGAZ SA. The aeroderivative GTC 1000 (figure 2, right), based on TURMO IV C (figure 2, left), operating on natural gas, is used in a power group driving two serial centrifugal compressors for the compression of the associated drill gas, in one SC OMV PETROM SA oil exploitation, at Țicleni – Gorj. Researches have also been conducted regarding the valorisation of the landfill gas in a aeroderivative gas turbine applicable to cogeneration groups [2]. A project for a cogeneration application using the GTE 2000 aeroderivative gas turbine has been started in 2000. The result of the project is a cogeneration plant, with two independent lines, producing electric and thermal (hot water) energy, located in the municipality of Botosani, with SC TERMICA SA as beneficiary (figure 3, left). The experience acquired from the GTE 2000 cogeneration plant has been used in a new project for a medium power aeroderivative gas turbine cogeneration plant, the application using the ST 18 A aeroderivative gas turbine, manufactured by Pratt & Whitney. The ST 18 A aeroderivative gas turbine has been derived from the aviation PW 100 through redesigning a series of components of which are distinguished the combustion chamber, the case and the intake. Furthermore, the ST 18 A has been designed and manufactured to operate with water injection in the combustion chamber (duplex burners), method that ensures the reduction of NO_x emissions. The application consists in a cogeneration plant, with two independent cogeneration lines, producing electric and thermal (superheated steam used in the oil extraction technologic process) energy. The beneficiary of the application is SC OMV PETROM SA, Suplacu de Barcău, Bihor County (figure 3, right) [8]. What makes the difference between aviation and aeroderivative gas turbines are operating conditions and reliability. Thus, aviation gas turbines have over the period of their useful life so many ordered starts and stops (associated with aircraft flight), short operation between starting and stopping (of hours), short periods between revisions (after each stop) and overhauls (after more than 1,000 hours of operation), the lifespan of about 12,000 cumulative hours of operation. Aeroderivative gas turbines can operate up to 8,000 hours continuously without ordered stop, overhauls are

made at intervals up to 30,000 cumulative operating hours and, for some brands, the cumulative operating ranges may be even higher.



Figure 1. AI 20 turboprop (left) and AI 20 GM gas turbine (right) [2]

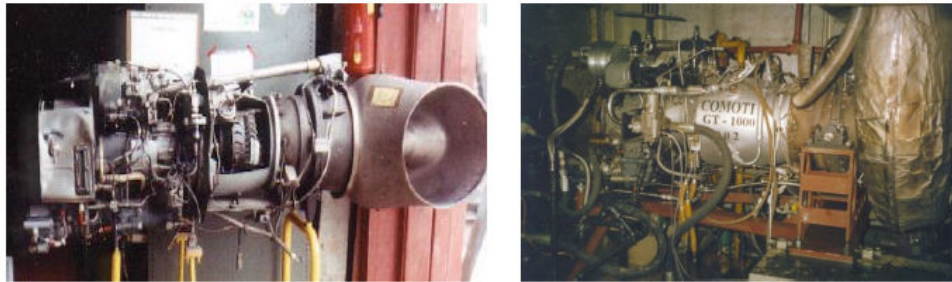


Figure 2. TURMO IV C turboshaft (left) and GTC 1000 gas turbine (right) [2]



Figure 3. GTE 2000 – Botoșani (left) and 2xST 18 – Suplacu de Barcău (right) plants

2.1. Classic and alternative fuels for gas turbine cogeneration groups

The performances of the gas turbine cogeneration groups (efficiency and emissions) depend in high degree of the type and physical and chemical properties of the used fuels. Depending on the lower heating value (LHV), in relation to natural gas ($\text{LHV}=30\text{--}45 \text{ MJ/Nm}^3$), typi-

cal gas fuels can be classified as [9]: high heating value ($\text{LHV}=45\text{--}190 \text{ MJ/Nm}^3$; butane, propane, refinery off-gas), medium heating value ($\text{LHV}=11.2\text{--}30 \text{ MJ/Nm}^3$; weak natural gas, landfill gas, coke oven gas), low heating value ($\text{LHV}<11.2 \text{ MJ/Nm}^3$; BFG - Blast Furnace Gas, refinery gas, petrochemical gas, fuels resulted through gasification etc).

2.1.1. General requirements regarding the utilization of fuels in gas turbines

For the gas turbines used in cogeneration groups, for economic reasons, the most used fuels are heavy oil and waste products from various manufacturing or chemistry processes [3]. Using liquid fuels imposes: ensuring combustion without incandescent particles and deposits on the firing tube and the turbine; decreasing the corrosive action of the burned gases caused by the aggressive compounds (sulphur, lead, sodium, vanadium, etc.); solving the pumping and atomization issues (filtration, heating, etc.). A series of fuels must be well purified or filtrated for eliminating water, solid particles or some remiss substances. Heavy liquid fuels must be heated to a convenient temperature to allow their proper pumping and spraying. Coke number and tar number are of particular interest for burning in gas turbines. Coke number (carbon residue) represents the residue left by an oil product (fuel oil, diesel, etc.) when burned in special conditions (closed space, restricted air access, etc.), expressed in mass percent. Tar number indicates the presence of resins, aromatic hydrocarbons, etc. but it must be considered for information only. In order to define the combustion behaviour of a heavy liquid fuel (like oil) it would be indicated to consider as a criterion the product of the coke number and tar number [10]. In terms of reusing aviation gas turbines in industrial purposes, the possibilities of using liquid fuels are decreasing. For each application, the requirements of the beneficiary must be analysed related to the characteristics of the fuels affecting the combustion (density, molecular weight, evaporation limit, flammability temperature, volatility, viscosity, surface tension, latent heat of vaporization, calorific value, the tendency for soot, etc.). In terms of using gas fuels, the problem is less challenging due to their thermal stability, high heating value, lack of soot and tar. However, in order to ensure the pressure level required by the gas turbine, afterburning, etc., the elimination of water and different impurities, a control – measurement station must be provided for the gas fuels to be used (natural gas at 2xST 18 plant – figure 4). Some alternative gas fuels (resulted



Figure 4. Control – measurement station for natural gas at 2xST 18 – Suplacu de Barcău plant (left) with booster (right) 1 – cogeneration power plant; 2 – control – measurement station; 3 – booster

through gasification and biomass pyrolysis), biogas, residual gases from industrial processes (rich in hydrogen) can play an important role in the operation of the gas turbine cogeneration groups, but they must reach some requirements regarding the calorific value and the composition [11]. Therefore there is necessary to eliminate the impurities, tar, to limit the sulphur and its compounds to 1 mg/Nm^3 , respectively the alkaline metal compounds to 0.1 mg/Nm^3 [12].

2.1.2. Alternative fuels – Characteristics and consequences regarding their use in gas turbine cogeneration groups

The biogas produced through anaerobic fermentation is cheap and constitutes a renewable energy source producing, from burning, neutral carbon dioxide (CO_2) and offering the possibility of treatment and recycling for residues and secondary agricultural products, various biowaste, organic waste water from industry, sewage and sewage sludge. The properties and the composition of biogas are different depending on the raw material used, processing system, temperature, etc. The comparative compositions of natural gas and biogas are given in table 1 [13]. For both fuels the main component (giving the energetic value) is the methane (CH_4), the significant differences being given by the high content of CO_2 and H_2S (hydrogen sulphide) in biogas. Technically, the main difference is given by the Wobbe index for natural gas (see chapter 2.2), two times higher than the index for biogas. This leads to a limited possibility of replacing the natural gas with biogas because only gases with similar Wobbe index can substitute each other. The improvement of the biogas can be achieved by replacing CO_2 with CH_4 so as to approach the characteristics of natural gas. Furthermore, the water and hydrogen sulphide must be eliminated to avoid the harmful action of the resulted sulphuric acid on different components of the cogeneration group (gas turbine, after-burning installation, heat recovery steam generator, etc.). Landfill gas resulted from waste deposits represents a cheap energy source, with a composition similar to the biogas resulted from anaerobic fermentation (45-60 % methane, 40-55 % carbon dioxide) [2]. When it comes to using biogas in gas turbine cogeneration groups or introducing it in the natural gas network, special treatment is required (condensate separation, drying, adsorption of volatile substances, etc.). Dimethylether (DME, $\text{CH}_3\text{-O-CH}_3$) is a clean alternative fuel which can be produced from fossil fuels, namely coal or vegetal biomass gasification. It can be transported and stored similar to liquefied petroleum gas (LPG), its physical and chemical characteristics, related to natural gas in Ardeal (99.8 % CH_4 and 0.2 % CO_2), being given in table 2 [14]. The flame produced by burning the dimethylether is very similar to the flame produced by the natural gas (figure 5), which makes it suitable to be used as fuel in transportation, cogeneration groups, etc.

Through biomass of coal gasification (with oxidant agents such as oxygen, air, steam, etc.) it can obtain synthesis gas (syngas) with main components hydrogen (H_2) and carbon monoxide (CO). The syngas can be used to obtain methanol, hydrogen, methane, etc. or can be used as fuel in gas turbine cogeneration groups. Since leaving the gas-producing installation the gas contains ash particles and various compounds of chlorine, fluorine, alkali metals, etc., which must be removed to protect the cogeneration line. Through gasification of differ-

ent biomass categories and utilization of different gasification technologies, the composition of the resulted gas and the lower heating value (LHV) can vary according to tables 3 and 4 [12, 15]. Tables 1 and 3 show that the lower heating values for biogas and syngas are lower than for the natural gas, requiring, in their application in cogeneration groups, higher mass flow rates with minimum pressure losses. Therefore, the injection nozzles of the gas turbine and the burners of the afterburning installation must be designed for velocities allowing a homogenous mixture between fuel and oxid, as well as low pressure losses. The syngas contains high quantities of hydrogen which affect the combustion in gas turbine cogeneration groups in terms of flame stability, combustion efficiency, etc. Using hydrogen as fuel and introducing a component with dilution role (steam, nitrogen, etc.) the operation of the gas turbine is affected [16].

No.	Name	Natural gas	Biogas
1	CH ₄ [vol %]	91.0	55-70
2	C _n H _{2n} [vol %]	8.09	0
3	CO ₂ [vol %]	0.61	30-45
4	N ₂ [vol %]	0.3	0 - 2
5	Lower heating value [MJ/Nm ³]	39.2	23.3
6	Density [kg/Nm ³]	0.809	1.16

Table 1. Composition, physical and chemical proprieties for natural gas and biogas [13]

No.	Name	Natural gas (Ardeal)	Dimethylether
1	Theoretical combustion temperature [°C]	1,900	2,000
2	Autoignition temperature [°C]	650-750	350
3	Lower heating value [MJ/Nm ³]	35.772	59.230
4	Explosion limit [% gas in air]	5 - 15.4	3 - 18.6
5	Density [kg/Nm ³]	0.716	2.052

Table 2. Physical and chemical characteristics for natural gas (Ardeal) and dimethylether [14]

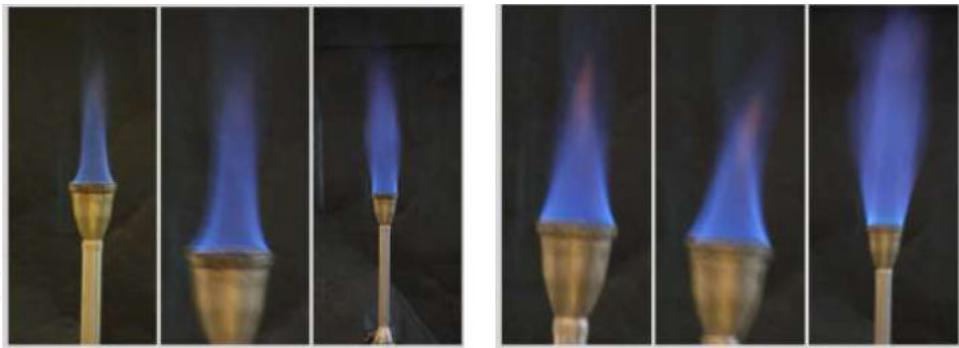


Figure 5. Flame of Bunsen burner, with grid type flame stabilizer, on natural gas (left) and dimethylether (right) [14]

Name	Syngas chemical composition [%]						Lower heating value [MJ/Nm³]
	CO	H ₂	CH ₄	C _n H _{2n}	CO ₂	N ₂	
Dry oak	18.3	16.9	2.8	0.5	16.0	-	5.422
Dry beech	19.4	17.5	2.6	0.6	15.0	49.3	5.526
Dry fir	15.1	19.1	1.6	0.9	15.8	57.1	4.053
Wood coals	31.2	6.3	2.9	-	2.5	57.1	5.702

Table 3. Chemical composition of syngas and lower heating values resulted from biomass gasification [15]

CO [%]	H ₂ [%]	CH ₄ [%]	N ₂ [%]	H ₂ O [%]	CO ₂ [%]	LHV [MJ/Nm³]	Observations
16	6	4	56	18	-	4.1	Air gasification
16	6	4	56	15	3	4.1	Air gasification
40	13	15	3	-	29	11.826	Oxygen gasification

Table 4. Chemical composition of syngas and lower heating values resulted from different methods of gasification [12]

Solving the fuels interchangeability issue for gas turbine cogeneration groups, by developing high level combustion technologies for alternative fuels, particularly hydrogen, will have a major impact on system efficiency and environment.

2.2. Fuels interchangeability and validation criteria

Interchangeability in gas turbine cogeneration groups represents the capability to replace a gas fuel with another without affecting the application or the installation burning the gas fuel. The used gas fuels consist in mixtures of combustible gases (methane and other light hydrocarbons, hydrogen, carbon monoxide) and inert gas (mostly nitrogen, carbon dioxide, water vapor). Depending on the combustible gases ratio (usually methane), the gas fuels can

have high or low heating value. Density and temperature of the used fuel, as well as the environmental temperature, can affect the performances and lifespan of the equipments in the cogeneration group. According to these influence factors, the most important parameter for characterizing the interchangeability is the Wobbe index (named after engineer and mathematician John Wobbe), defined as ratio between the lower heating value (LHV) and the square root of density of the fuel, relative to air density (d_{rel}):

$$Wo = LHV / (d_{rel})^{0.5}$$

(1)

$$d_{rel} = \rho_{comb} / \rho_{air}$$

(2)

Therefore, two gas fuels, with different chemical compositions but the same Wobbe index, are interchangeable and the heat delivered to the equipment is equivalent for the same fuel pressure. Table 5 gives the values of Wobbe index for several gas fuels. In order to consider the temperature of the fuel, the Wobbe index can be corrected with the temperature. According to [17], two fuels are interchangeable if they respect:

$$\frac{\Delta p_2}{\Delta p_1} = \left(\frac{Wo_1}{Wo_2} \right)^2 \left(\frac{A_1}{A_2} \right)^2$$

(3)

where Δp_1 and Δp_2 represent the overpressure of fuel 1, respectively 2, Wo_1 and Wo_2 – Wobbe indexes of fuel 1, respectively 2, A_1 and A_2 – injection nozzle area for the two fuels.

No.	Gas name	Wobbe index [(MJ/Nm³)]
1	Natural gas	48.554
2	Liquefied petroleum gas	79.993
3	Methane	47.947
4	Ethane	62.513
5	Propane	74.584
6	Carbon monoxide	12.812
7	Biogas	27.3
8	Dimethylether	47.422
9	Hydrogen	38.3

Table 5. Wobbe index for various gases [2, 13, 14]

Therefore, the validation criteria for replacing a fuel with an equivalent one are given by: autoignition temperature, flame temperature (with higher influence on NO_x formation), flame velocity, flashback, efficiency, NO_x and CO emissions, flue gas dew point, etc. Autoignition temperature of gas fuel in mixture with air is the temperature on which the instantaneous and explosive autoignition occurs, without the existence of an incandescent source of ignition. The turbulent flame is generally less stable than the laminar flame, the instability in flame front break-up field being emphasized by the increase in tube diameter. Free swirl turbulent flames are more prone to flame front break-up than the laminar ones due to the higher peripheral jet velocity. For turbulence angles greater than 30° , the stability area is achieved on the contour of the burner only for rich mixtures [18]. In areas with poor mixture, due to the decrease in velocity, the backflow can occur without flame attachment on the burner edge. The velocity distribution in the swirl flow determines the stabilisation of the flame as a central suspended one. Components with rapid burning, such as hydrogen, accelerate the flame velocity with a tendency to backflow or extinguishment. The backflow tendency of the flames is proportional with the ignition velocity of the fuel gas, a high velocity leading to a high effect. It is also dependent of the primary air proportion and the components with reduced burning velocity can lead to flame front break-up. In order to consider these factors, an empiric relation has been established for the flame front break-up index at interchangeability I_{ret} [19]:

$$I_{\text{ret}} = \frac{k_i f_i}{k_b f_b} \left(\frac{\text{LHV}_i}{\text{LHV}_b} \right)^{0.5} \quad (4)$$

where: k – constant concerning the flame front break-up limit; f – factor concerning primary air; LHV – lower heating value; b and i – indexes regarding the control fuel, respectively the replacement fuel. A particular issue is raised by the fuels with reduced heating value. Therefore, the landfill gas contains over 40 % CO_2 , requiring a suitable fuel feeding in order to achieve combustion. The fuels with reduced heating value have a small range of flammability requiring, at partial loads or transient operating regimes, the utilization of a supplementary fuel (such as propane). The mass flow rates necessary for gas turbine operation on reduced heating value gas fuels are high (neglecting the water or steam injection in the gas turbine) compared with the operation on natural gas, fact that modifies the compressor's operating characteristic [20]. From biomass gasification with air, it is obtained syngas with LHV of 4-6 MJ/Nm³, and from the gasification with steam or oxygen (see table 4) LHV of 9-13MJ/Nm³. An alternative for increasing lower heating value is the mixing with natural gas. Therefore, if the landfill gas has a LHV of 17-20 MJ/Nm³, an equivalent lower heating value can be obtained by mixing 60 % gas with reduced heating value with 40 % CH_4 , with respect to the composition described in [21].

2.3. Converting the aviation gas turbines from liquid to gas fuels operation

The complexity of thermo-gas-dynamic processes defining the gas turbine operation in a cogeneration group require theoretical and experimental research activities on gas turbines in order to accomplish the conversion from liquid to gas fuels operation. For the gas turbines on market, in exploitation, the exploitation and maintenance technical specifications are generally known, being provided by the producer. When the object of the research is an existing gas turbine lacking the technical documentation which completely define the constructive solution, the issue must be approached through activities of experimentation, measurements, CAD 3D modelling, numerical simulation in CFD environment, constructive modifications and renewed experimentation in order to validate the constructive solutions, permanently aiming the performances correlated with the maximum effectiveness (thrust, power), minimum specific fuel consumption, maximum efficiency, versatility on fuel conversion, maximum availability, minimum operation and maintenance costs.

2.3.1. General criteria – Researches concerning the modifications on a gas turbine for gas fuel operation

The basic procedure for an aeroderivative gas turbine is to keep the rotor assembly, compressor – turbine, which is the „heart” of the gas turbine, from the aviation gas turbine and to redesign the combustion chamber in order to operate on a different fuel than the kerosene. Therefore, for the basic gas turbine in the turboshaft category, at least the combustion chamber must be designed for gas fuels operation. The shaft of the power turbine is mechanically connected to a driven load, mechanical work consumer, depending on the application involving the aero-derivative gas turbine (electric generator, compressor, pump, etc.). The command and automatic control system of the aero-derivative gas turbine are designed depending on the application. The bearings can be redesigned, achieving a conversion from rolling bearings to slide bearings. For the basic turboprop (designed for propeller aircrafts), at least the combustion chamber and the reducing gear box and/or the gas generator’s turbine must be redesigned, depending if the turboprop does or does not include free turbine. Usually, only the gas generator is used, eliminating the gear box. The issues concerning the automatic control system and the bearings are identical to those of the turboshaft. For the basic turbojet (simple flow jet predominantly for military aircrafts) the redesigning of the combustion chamber and the designing of a power turbine gas-dynamically connected to the gas generator are necessary [2]. The issues concerning the automatic control system and the bearings are also identical to those of the turboshaft. Regarding the combustion chamber, is desired to constructively alterate it as little as possible, maybe only in terms of injection system. Due to the fact that the rest of the parameters characterizing the operating process remain unchanged, those regarding zero velocity and ground conditions of the basic gas turbine, the operation of the combustion chamber can be considered as in terms of gas-dynamic similarity. A first problem that must be studied when replacing the fuel is maintaining the combustion ef-

iciency. A second one concerns the maintaining of constructive-functional temperature distribution (on the walls of the firing tube, in the outlet area of the combustion chamber and inlet area of the turbine). On the background of the assembly gas-dynamic characteristics, the unevenness of the temperatures field on the outlet of the combustion chamber (temperature map) is determined by the geometric characteristics of the dilution area (diameter, length, number and area of holes, etc.) and the characteristics of fuel feeding in the primary area (atomization, jet angles, fuel specifications, etc.). The global temperature map is defined by equation (5) and the radial unevenness for the rotor bladed area is given by equation (6) [3]:

$$\theta_m = (T_{\max}^* - T_3^*) / (T_3^* - T_2^*) \quad (5)$$

Radial unevenness for the rotor bladed area express the manner of operation on the turbine blades:

$$\theta_r = (T_{\max r}^* - T_3^*) / (T_3^* - T_2^*) \quad (6)$$

In equations (5) and (6) the significance of symbols is: T_{\max}^* - maximum temperature peak; T_3^* - average temperature in the outlet section of the combustion chamber; T_2^* - average temperature in the outlet section of the compressor; $T_{\max r}^*$ - maximum average radial temperature, circumferential arithmetic mean on the entire section. Normal values for θ_m , depending on the gas turbine, are in the 20-25 % range, with reported values of 35 %. In direct connection with the temperature map on the walls of the firing tube, the equivalent stress of the material must be considered when replacing a fuel with another. In the case of the AI 24 gas turbine modification for operation on gas fuels in the cogeneration group, a difference of 15 % has been reported in the temperature map, considering the flattening of the temperature peaks when passing through the turbine [22]. The adopted solution has been the generalization of the results obtained by National Research and Development Institute for Gas Turbines COMOTI Bucharest for the AI 20 GM (figure 1) and MK 701 gas generators. In order to achieve the AI 20 GM gas turbine on natural gas (derived from AI 20 on liquid fuel) the adopted constructive solution has been the modification of the injection system, without altering the firing tube (figure 6). The researches for this transformation have been based on test bench experiments with liquid fuel (in low pressure similitude conditions). In order to reach the functional optimum on natural gas, several injection nozzles have been designed and experimented, according to table 6 [3].

Nozzle no.	10 Ø3 holes at a 2α angle	Diameter of central hole Ø [mm]
1	90°	3
2	70°	without central hole
3	80°	without central hole
4	70°	3
5	80°	3
6	100°	without central hole

Table 6. Configuration of the experimental injection nozzles (see figure 6), for AI 20 GM on natural gas [3]

Only nozzles with 10 holes of the same diameter have been experimented in order to ensure velocity, penetration and safety in operation. The central hole affects the stability of the combustion process, increases the flame radiation and the temperature on the walls of the firing tube. The tie criterion for various injection nozzles for natural gas has been the temperature of the blade on hub. It has been noted that nozzle no. 3 leads to low frequency vibrations in a large range of operating regimes, functionally inadmissible. When operating on natural gas, the combustion efficiency increases with the operating regime, the process being unaffected by the vaporization, but only by the mixing. Following the experimentation, nozzle no. 2 has been selected (with 10 Ø3 holes at $2\alpha=70^\circ$, without central hole). For all experimentation regimes, the circumferential temperature map values did not pass 18 %. The same manner of minimum configuration modifications has been applied for the rest of the gas turbines transformed for operating on natural gas (TURMO, MK 701, etc.). Therefore, the firing tube and the combustion chamber case have been kept unmodified for all gas turbines, only redesigning the injection system. Satisfying results have been obtained for the experimentation of TURMO: good stability, but in a more limited range compared with other gas turbines (due to the dependency on the mixing process); temperature map values of 22 % (for the aimed 20 %). For MK 701, the values on the temperature map have reached max. 20 %. A particular problem is considered when the aim is the integration of the gas turbine, modified for operating on natural gas, with an existing boiler. The heat recovery steam generator can be derived from an energy steam boiler, a technological steam boiler or a hot (warm) water boiler. The integration analysis for an aeroderivative gas turbine with a hot water boiler shows that the temperature of the burned gases on the stack must be in the usual value range and the pressure loss at the passing through the modified boiler (in the cogeneration group) must be lower than the pressure loss on the initial boiler [23]. The modifications necessary for operating the gas turbine on gas fuels with reduced lower heating value, compared with the operation on natural gas, are slightly more complex. Therefore, Mitsubishi Heavy Industries Ltd., with extensive experience in manufacturing gas turbines on BFG (Blast Furnace Gas), considered the heating value of the gas fuel as the key factor in the modifications scheduled for the gas turbine [24]. Depending on the actual application, more modifications can be operated on the gas turbine, compared with the ones in table 7.

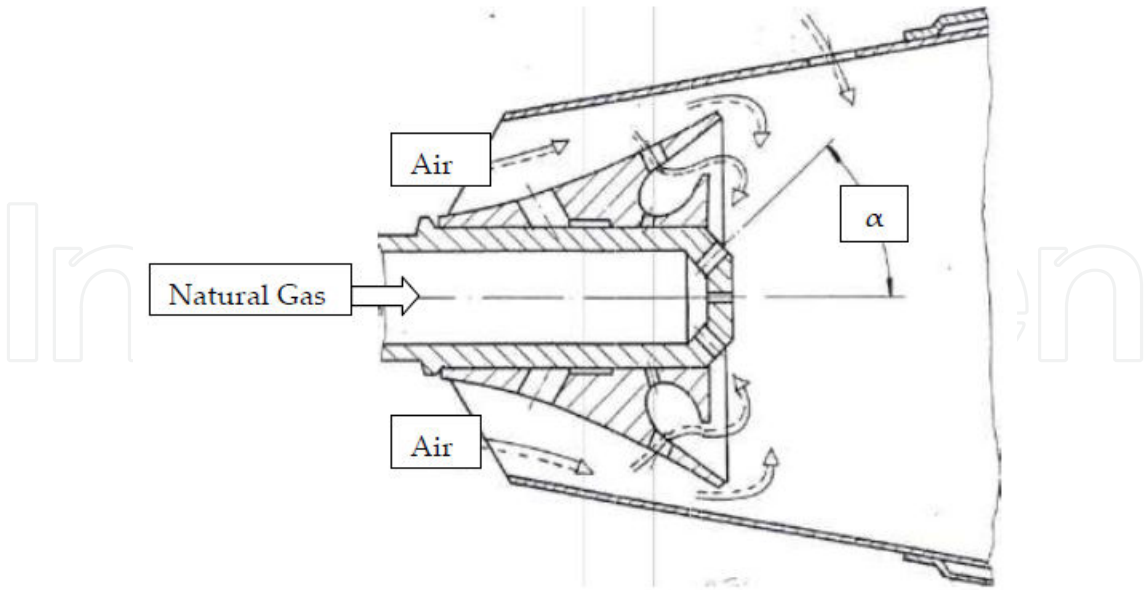


Figure 6. Modification of the injection system for AI 20 GM gas turbine [3]

Lower heating value [MJ/Nm³]	20.95-41.9 (High)	35.61 (Natural gas)	8.38-29.33 (Medium)	2.51-8.38 (Low)
Air compressor	Standard	Standard	Standard	Modification
Combustor	Standard (Minor mod.)	Standard	Standard (Minor mod.)	Modification
Turbine	Standard	Standard	Standard	Standard
Fuel system	Standard (Minor mod.)	Standard	Standard (Minor mod.)	Modification

Table 7. Necessary modifications for a gas turbine, depending on lower heating value of the fuel [24]

2.4. Converting a gas turbine from liquid to gas fuel operation for landfill gas valorisation

Converting the gas turbine from liquid fuel to gas fuel operation in order to achieve the valorisation of the landfill gas has known two main steps, respecting the principles in chapter 2.3: converting the TV2-117A gas turbine from operating on liquid fuel (kerosene) to gas fuel (natural gas), resulting the TA2 gas turbine; converting the TA2 from operating on natural gas to operating on landfill gas, resulting TA2 bio. In order to achieve these results, numerous numerical simulations in CFD environment and tests have been used for validating the adopted solutions.

2.4.1. Numerical simulation, experimental activity, methods and equipments

Numerical simulation on the TV2-117A gas turbine (figure 7, left) on kerosene has been made in order to obtain a reference model for the gas turbine conversion on gas fuels, particularly landfill gas. An eighth of the geometric model, corresponding to one injection nozzle, has been used in simulations considering the combustion chamber symmetry. The boundary conditions have been provided by the producer in the technical specifications for three operating regimes: take-off, nominal and cruise (with the corresponding temperatures of 1123, 1063 and 1023 K). For simulating the combustion process in the TA2 bio gas turbine, the used fuel has been a synthetic landfill gas with equal volume proportions of methane (CH_4) and carbon dioxide (CO_2). The real landfill gas contains other chemical species, in small proportions, which have been considered impurities and have not been taken into account. The numerical simulations have been made on the TA2 with modified injection system, particularly on the injection nozzles level (figure 8). The modelling of the injection nozzles has been achieved starting from the geometry of the natural gas nozzles. Only the injector's outer body have been kept from the liquid operating gas turbine, eliminating all elements related to the atomization system of the liquid fuel. Related to the initial configuration of the injector, only the diameter of the secondary channel and the configuration of the connection with the injection nozzle have been kept unmodified.



Figure 7. TV2-117A gas turbine (left) with detailed combustion chamber area (right)

The numerical simulations for the modified injector (figure 8) have taken into consideration the variation of the injection pressure (7.65 - 8.5 bar), of the injection angle β (70° - 85°) and the position related to the injector's body L (1 - 5 mm). Following the numerical simulations, the optimum configuration has been selected and the eight injectors have been manufactured along with the injection ramp (figure 10, right), consisting in a circular pipe connected to each injector. The configurations of the injectors for liquid fuel and landfill gas are given in figure 9. The elements eliminated from the initial configuration are the following: the liquid fuel feeding system; the liquid fuel automatic control system; the command system for the actuators controlling the guide vanes and the first three statoric stages of the compressor; the deicing system. The experimentation of TA2 bio has been made in the experimental facility of National Research and Development Institute for Gas Turbines COMOTI Buchar-est (figure 10) in the following configuration: TA2 bio gas turbine installed on test bench; test cell lubricating system and fuel feeding system for the gas turbine; exhaust system for

the burned gases; monitoring system for acquiring functional parameters. In figure 10 (right) is a pipe ramp ring, yellow color, for gas fuel supply.

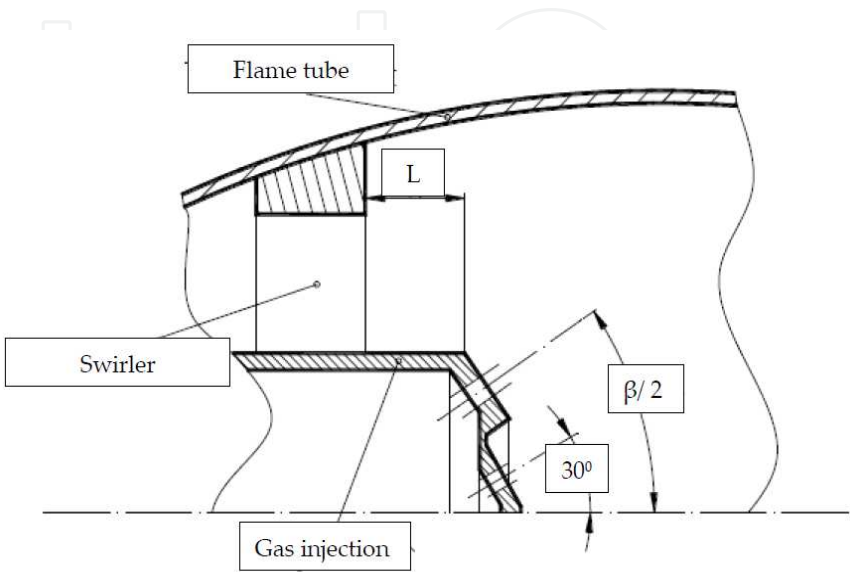


Figure 8. Injection nozzle configuration for landfill gas [2]



Figure 9. Injectors for liquid fuel for TV2-117A (left) and landfill gas for TA2 bio (right) [2]

A series of experimentations have been made, the simulated landfill gas being obtained by mixing natural gas with carbon dioxide (provided from tanks). The measurements have been made with the equipments of the test facilities. A ramp of 17 double thermocouples located at the outlet of the combustion chamber, with measuring points at one third and two thirds of the outer firing tube circumference allow the measurement of the T_{ex} and T_{in} temperatures on two concentric rings (figure 11 right).



Figure 10. TA2 gas turbine (left) and TA2 bio gas turbine in the test cell (centre, right)

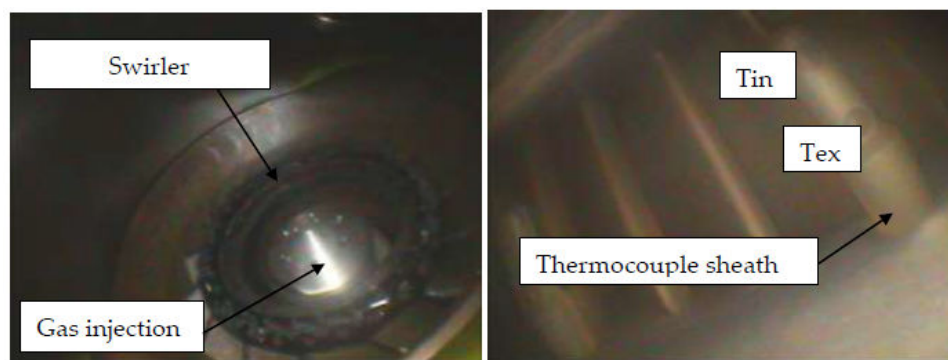


Figure 11. Boroscopy images of the gas injection nozzles – natural gas (left) and the thermocouples (right)

2.4.2. Results and discussion

The numeric simulations on kerosene [2, 5] have shown that, for the reduced operating regimes, the flame reaches in high degree the area between two adjacent injectors. Table 8 presents the numerical results for landfill gas combustion in terms of methane mass fraction, illustrating the jet shape, and burned gases temperature in the outlet section of the combustion chamber. Analysis of data in table 8, with respect to temperature maps, aiming to obtain a compact jet in order to protect the walls of the firing tube, have helped selecting the geometric configuration of the injection nozzle: $\beta = 70^\circ$ and $L = 3$ mm, used for designing the functional model experimented on TA2 bio, for a mixture of natural gas and carbon dioxide. The experiments have been developed in several series, figure 12 presenting one of the models of variation for the components of the synthetic landfill gas mixture. The experimental results have been synthetized in figures 12 and 13. Figure 13 presents the numerical and experimental results for the outlet section of the combustion chamber.

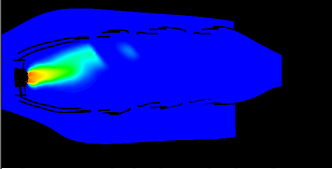
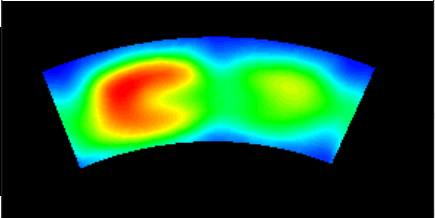
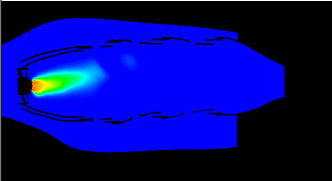
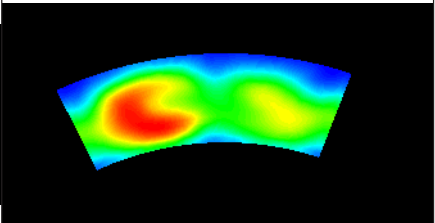
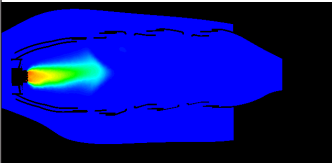
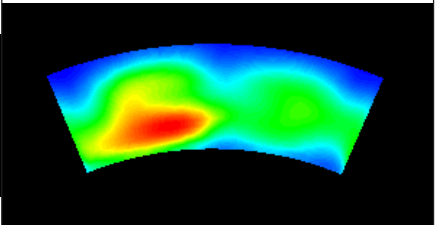
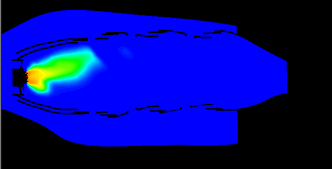
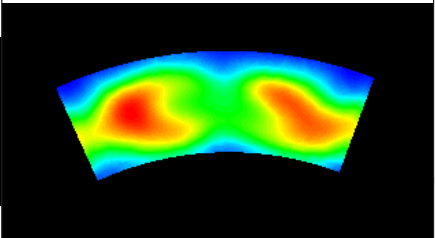
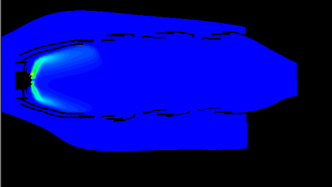
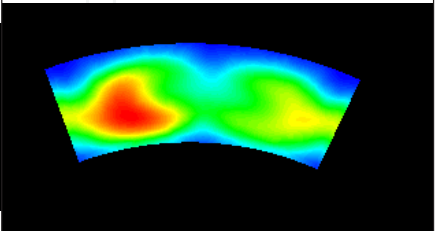
Parameters			Results	
L [mm]	β [°]	p [bar]	Fuel injection jet	Temperature on combustion chamber outlet
1	70	7.65		
3	70	7.65		
5	70	7.65		
3	80	7.65		
3	85	8.50		

Table 8. Numerical results for landfill gas combustion simulation [2]

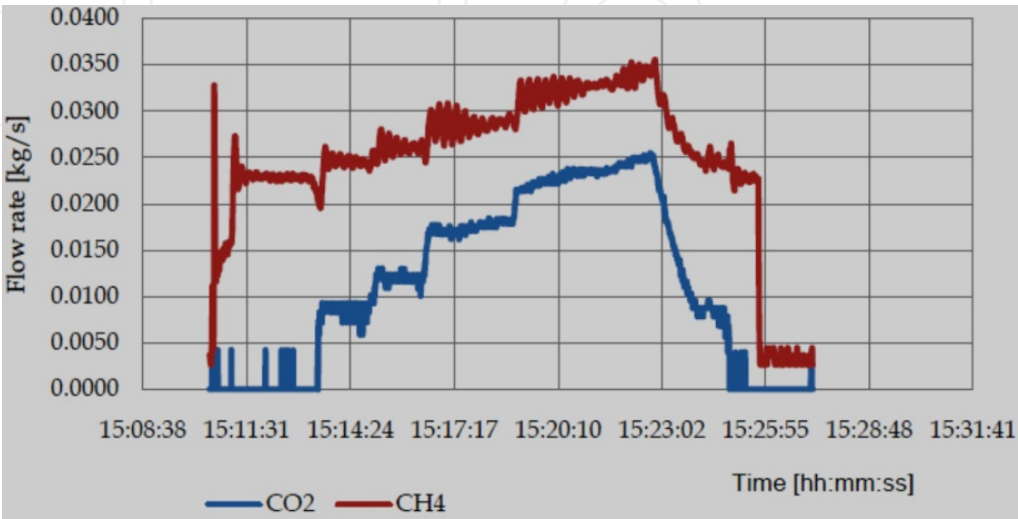


Figure 12. Variation of the mass flow rates of carbon dioxide (CO₂) and natural gas (CH₄) injected in the combustion chamber [2]

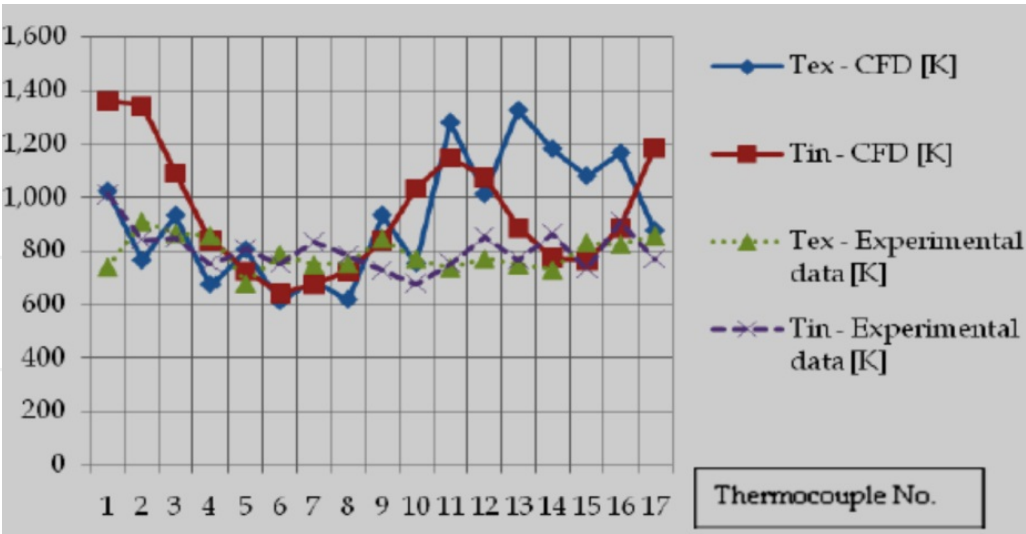


Figure 13. Comparison between the numerical and experimental temperature

The experimentations have proved a stable operation of the TA2 bio gas turbine on different operating regimes, mainly defined by the mass flow rate and the ratio between the mass flow rate of the natural gas and carbon dioxide. Figure 13, particularly the central area, shows

a concordance of the numerical and experimental data, proving that modification of gas turbines operating on alternative gas fuels can be made based on numerical simulations in CFD environment. The model of a cogeneration plant for electric and thermal energy is illustrated in figure 14.

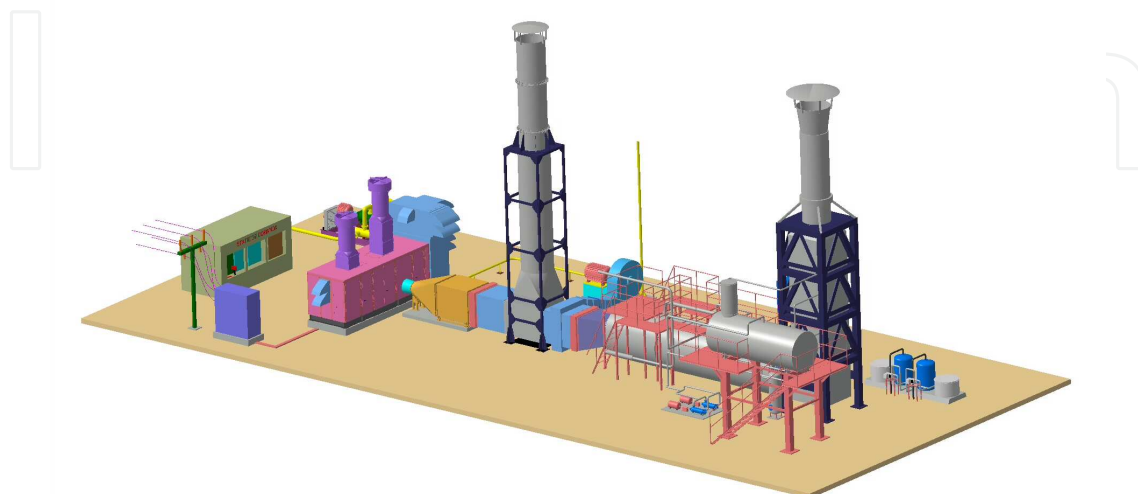
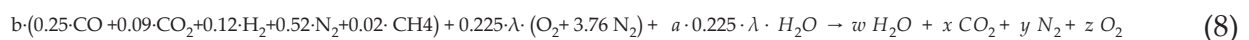


Figure 14. Model of an aeroderivative gas turbine cogeneration plant operating on natural gas and landfill gas

3. Flexibility of gas turbine cogeneration groups and emissions reduction – Future researches

Gas turbine cogeneration groups, alone or in combination with fuel cells, can play an important role in the general assembly of energy production and emissions reduction. The NO_x reduction must be regarded considering the ensurance of cogeneration group performances in a flexible manner, optimization being possible for a fuel [25]. A higher efficiency implies the optimization of the entire cogeneration plant (gas turbine, afterburning, heat recovery steam generator, etc.). The efficiency must be maintained for partial loads (even below 50 %) or for environmental conditions modification. Starting from 2002, Siemens has taken into consideration the flexibility, eliminating the high pressure barrel of the heat recovery steam generator which requires a long process to reach a certain temperature (in order to avoid the occurrence of thermal tensions). Regarding the flexibility, the efficiency and the emissions reduction in gas turbine cogeneration groups, important steps have been made: reduced NO_x burners have been introduced in applications; the lifecycle has been analyzed for efficiency increase; the period between maintenance controls has been extended and the conversion from one fuel to another for multi-fuel engines has improved [7]. The factors determining the formation of pollutant agents exhausted along with the burned gases from the gas turbines are [26]: temperature and air excess coefficient in primary area; homogenization of the

process in primary area; residence time of the products; “freezing” characteristic of the reaction near the firing tube, etc. For NO_x reduction, the temperature in the area of the combustion reaction and the areas of maximum temperature and the air jets distribution (stage combustion) need to be reduced. The final configuration of the combustion chamber of a gas turbine is a compromise between the NO_x level, performance and flexibility. Global reduction of the emissions leads to compromises between the emission levels of different components and the assembly characteristics of the combustion chamber (pressure losses, stability and ignition limits, etc.). New concepts must be promoted in order to solve this issue. The usual methods are represented by the water or steam injection in the combustion chamber of the gas turbine, leading to [12]: reduction of NO_x up to 25 ppm (for a 15 % O_2 volume participation in dry burned gases); increase in turbine power due to the increase in fluid mass flow rate (which can compensate the effect of increased temperature during summer); increase of flexibility of the installation in exploitation due to the possibility of load variation through steam flow rate variation. However, the high content of vapours in burned gases can lead to: acid corrosion occurrence (for fuels containing sulphure); increase in thermal stress on the combustion chamber; reduction of the heat recovery level, etc. Numerical simulations on TV2-117A (figure 15) for water injection in the combustion chamber (through duplex injectors, on natural gas) have shown that the water injection in truncated cone shape, at 45° , characterized by a 12 l/min mass flow rate, leads to minimum NO_x concentration in burned gases of 14 ppm. The analysis of combustion products for TA2 (see chapter 2.4), using NASA CEA program [27], has shown a decrease of the average maximum temperature. The composition of the landfill gas has been considered in equal volume proportions of methane and carbon dioxide, while the composition of the syngas has been considered that given by [19]. The calculation algorithm has started from the stoichiometric reaction of each fuel and imposing the operating regime (in terms of average maximum temperature of 1063 K for nominal regime) in order to determine the minimum quantity of air necessary for the reaction. Obtaining the equilibrium reactions has determined the calculation of the air excess coefficients for each fuel at the given regime, for dry operation. Starting from these initial values, water has been introduced in different proportions, up to 23 %. The supplementary quantity of fuel, necessary to reestablish the operating regime of the gas turbine, in terms of temperature (considering the pressure as unaffected), has been calculated in relation to the quantity of water. The general combustion reactions for each fuel, for the water injection case, for the nominal operating regime, are given by equation (7) for landfill gas and equation (8) for syngas:



There have been tracked the thermodynamic of the system and the concentrations of the reaction products, focusing on carbon monoxid (CO) and nitrogen oxides (NO_x). In these conditions, for the two regimes, the calculations have been made up to a injected water coefficient (noted „a”) in oxidant of maximum 2, equivalent to 23 % water in oxidant. The

maximum proportion of water in oxidant has been limited by the concentration of oxygen resulted from the combustion, minimum 11 %, necessary for the afterburning process. For the nominal operating regime and approximately 15 % water for landfill gas and 12.5 % for syngas, the gas turbine reaches the minimum limit of oxygen.

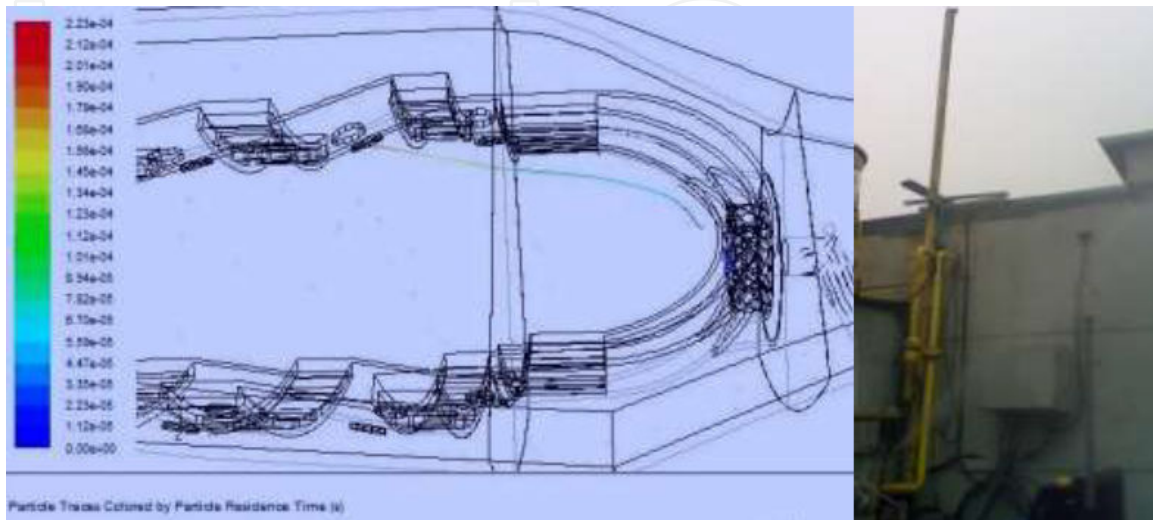


Figure 15. Numerical simulation of water injection in the combustion chamber of TA2 (left) and atomization tests with the duplex injector (right)

Figure 16 shows the variation of NO_x for the two fuels (landfill gas and syngas) for the nominal regime, depending on the injected water proportion. The results of the calculations illustrate that the use of afterburning along with the operation of the TA2 gas turbine, with water injection, for the good operation of the system, the NO_x produced by the gas turbine at 1063 K can only be reduced to 40 ppm for landfill gas and 38.5 ppm for syngas. The oxygen injected in the air can lead to nitrogen oxides reduction and combustion enhancement resulting [28]: reduction of ignition temperature; increase in flammability limit; increase in adiabatic temperature of the flame; increase in process stability and control; reduction of low heating value fuels consumption, etc. The adiabatic temperature of the flame increases with approximately 50 °C for 1 % increase in oxygen concentration. The volume of burned gases decreases with 12 % for the combustion of natural gas in 3 % oxygen enriched air [29]. Reduction of pollution through combustion in oxygen enriched environment can be used in afterburning installations (for primary or secondary air). Combustion in oxygen enriched environment can increase the efficiency and the flexibility of the cogeneration plant. When adding hydrogen to a gas fuel, there are affected the stability of the flame, the efficiency of the combustion and the emissions. Flame velocity for hydrogen combustion in air, in stoichiometric conditions, reaches 200 cm/s compared to the combustion of methane in air, for which the velocity is approximately 40 cm/s [29]. Adding hydrogen to the gas fuel of the gas turbine or afterburning installation can lead to CO and NO_x emissions reduction.

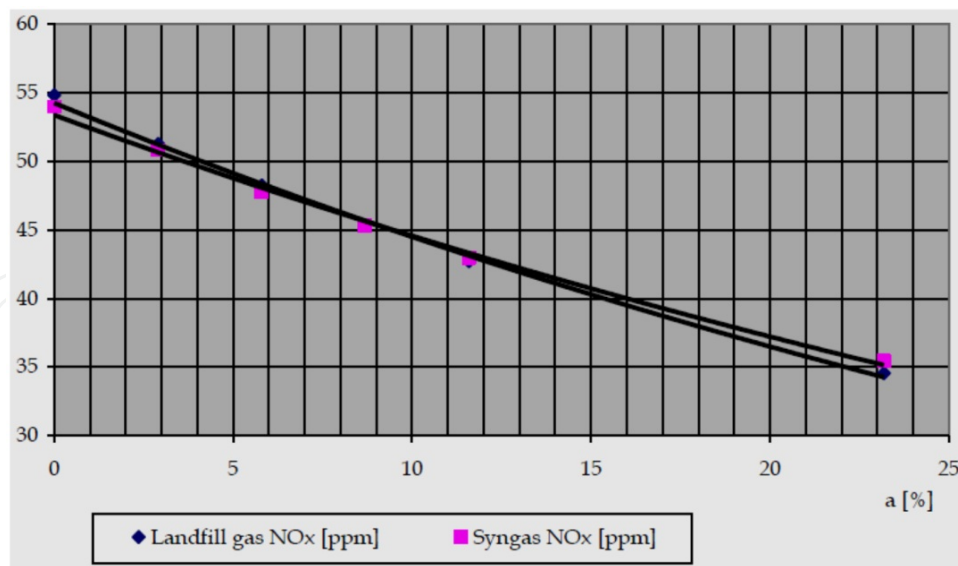


Figure 16. Variation of NO_x concentration for the two fuels, at 1063 K, depending on water proportion in oxidant (a)

3.1. Afterburning installation as interface between gas turbine and heat recovery steam generator

The burned gases flow when exiting the gas turbine is turbulent and unevenly distributed in transversal section. Therefore, backflow can occur in the transversal section of the recovery boiler. The unevenness of the flow and the variation in burned gases composition affects the operation of the afterburning. Therefore, the afterburning is influenced in terms of efficiency, emissions, flame stability, as well as corrosion of the elements subjected to the action of burned gases. For a good design of the inlet section in the recovery boiler it must be generally considered the following factors [30]: geometry and direction of the gas turbine exhaust; size of heat exchange surfaces; location of the afterburning burner; mass flow rate and average velocity of burned gases exiting the gas turbine; local velocities near the walls and on the first heat exchange surface. The gas turbine exhaust is generally not directly connected with the recovery boiler. After exiting the gas turbine (the case of 2xST 18 Cogeneration Plant at Suplacu de Barcău), the burned gases pass through a silencer, a by-pass assembly, a transom for the connection with the burner and then the afterburning chamber [8]. The gases flow must be parallel with the axis of the burner's connector (perpendicular to the burner plane). A uniform distribution of the flow in the transversal section ensures a good operation of the heat recovery steam generator, particularly regarding the superheater. Therefore, the necessary premises are created for ensuring low emissions on the cogeneration group. If the burned gases or the air are unevenly distributed, significant variation of the temperatures downstream the burner can occur. Velocity variation in the transversal section, upstream the burner, must not exceed, on 90 % of the burner's section, ± 15 % of the average velocity measured on the entire transversal section. In reality, the burned gases temperature downstream the burner will never be perfectly uniform. Even for a perfect flow distribution of the turbine gases, upstream the burner, the temperature in the area of each burner module will

be higher than the temperature between the modules. Therefore, the infrared analysis of the channel connecting the gas turbine and the afterburning installation (silencer – by-pass assembly – connecting transom), at 2xST 18 Plant, has shown unevenness in temperature distribution (figure 17). Considering these phenomena, the afterburning installation can compensate, in good conditions, the mass flow decrease in burned gases produced by the gas turbine at partial loads, keeping a corresponding load on the heat recovery steam generator. In case of turbine stopping, the heat recovery steam generator with the fresh air afterburning is able to keep the steam production at a certain level.



Figure 17. Temperature isotherms, in infrared, in the channel connecting the gas turbine and the afterburning installation (silencer – by-pass assembly – connecting transom)

3.2. Future research

Future research is part of the general context of increasing the flexibility of gas turbine cogeneration groups, the efficiency and reducing the emissions using numerical simulations in CFD environment and experimentations related to: utilization of alternative fuels in gas turbines and afterburning installations, injection of fluids in the cogeneration line in order to reduce the emissions, integrating the gas turbine with fuel cells, etc.

4. Conclusions

Along with the flexibility to alternative fuels feeding, the flexibility of a gas turbine cogeneration plant assumes the accomplishment of several requirements: capability of fast start; capability to pass easily from full load to partial loads and back; maintaining the efficiency at full load and partial loads; maintaining the emission to a low level even when operating on partial loads. Using aeroderivative gas turbines in the cogeneration field has allowed the scientific and technologic knowledge transfer utilization (design concepts, materials, technologies, etc.), which ensures a high degree of energy, from aviation to ground applications. The experience of National Research and Development Institute for Gas Turbines COMOTI Bucharest, in the field of aeroderivative gas turbines (AI 20 GM, TURMO, MK 701, etc.) has allowed the conversion of a gas turbine from liquid fuel to landfill gas, for cogeneration, in stable operating conditions.

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