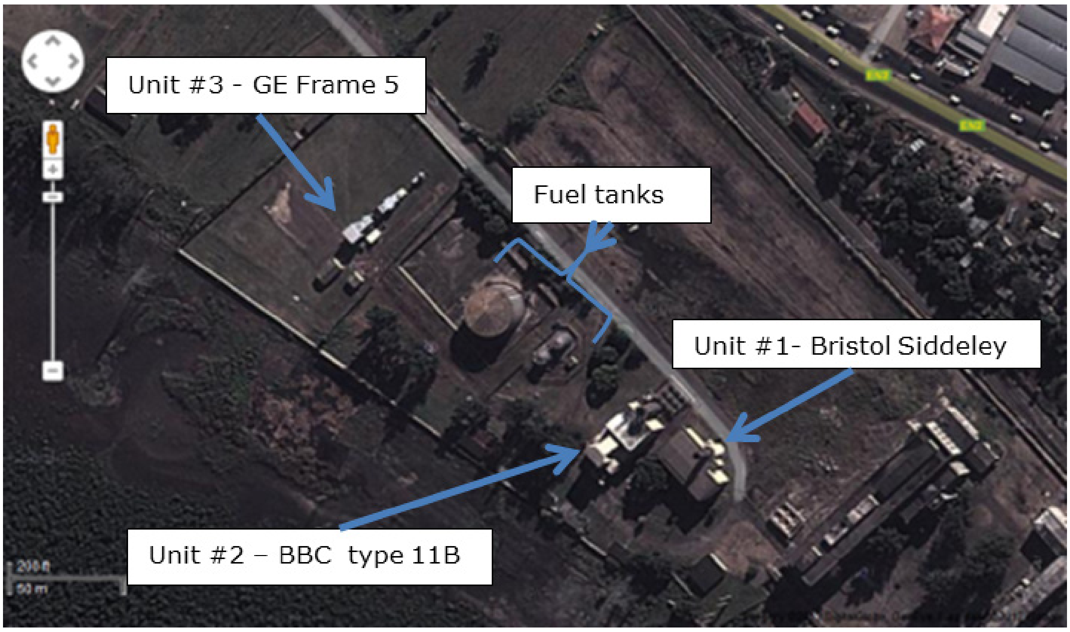
KTH Industrial Engineering
and Management

Optimization of Maputo Power Plant

Armando Abacar



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KTH Industrial Engineering and Management	**Master of Science Thesis EGI-2013-050MSC EKV952** **Optimization of Maputo Power Plant** Armando Abacar

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Abstract

The Electricidade de Moçambique, E.P. (EDM) is the power utility in Mozambique, responsible to generate, transport and distribute electricity all over the country. The company has three gas turbines installed at Maputo Power Plant. All units burn diesel oil and are used only for back up. Currently only the unit #2 is available for operation.

The main constraint that EDM faces is the high operation costs due to diesel price. Hence the company is considering converting units #2 and #3 to burn natural gas, resource available locally. The country is currently exporting natural gas to the neighbouring Republic of South Africa.

This MSc thesis project calculates the power output of all gas turbines when burning natural gas and optimizes the power plant capacity by proposing modifications of the current power turbine cycles to allow sustainable operation.

Keywords:

Gas turbines, Sustainability, Electricity

Table of Contents

1 Introduction

1.1 Energy overview in Mozambique

Mozambique (see map on Figure 1) is richly endowed with energy resources, but not all can be economically harnessed. While historically low electricity prices in the southern African region and relatively low petroleum prices globally have largely prevented most energy technologies and supply systems from competing in the market, the situation is now rapidly changing as the region faces severe power shortages and global petroleum prices are increasing. Some energy technologies however, are not yet mature enough to warrant serious consideration.

Human and animal energy: Humans and animals provide a substantial portion of the energy needs of poor communities in Mozambique, primarily in the form of travel, transportation, traction and water pumping. These are difficult to quantify and measure, however, and are therefore seldom recognized as an energy resource.

Oil and gas: Mozambique is an emerging giant in natural gas; more than 100 tera cubic feet (tcf) were discovered in the offshore Rovuma Basin (SPTEC Advisory, 2013). Pande and Temane gas fields (approximately 600 km north of capital city Maputo) have a capacity of 5 tcf. Currently there is gas pipeline connecting Temane to South Africa (KMPG, 2009).

Coal: Coal deposits exist extensively throughout the central-western Mozambique with estimated reserve of 15 billion tones and proven reserves of about 87 million tonnes (KMPG, 2009).

Biomass energy: Mozambique has about 65.3 million hectares of forest and other wood formations, with an annual wood and charcoal production potential of around 22 million tonnes (KMPG, 2009). Current consumption is 14.8 million tonnes per year. The abundant biomass resource and suitable climate also hold potential for biofuels production, which is estimated at 3 million barrels oil equivalent per day, without threatening food supplies for the country's rapidly growing population, or its biodiversity and protected conservation areas (KMPG, 2009).

Solar radiation: The average global solar radiation in the country is 5.7 kWh/m2/day, with a minimum average of 5.2 kWh/m2/day in Lichinga, and a maximum of 6.0 kWh/m2/day in Pemba and Maniquenique (KMPG, 2009). This resource, which is largely untapped, not only holds huge potential for small-scale off-grid energy supply for the country's scattered population, but could also significantly contribute to meeting the electric power demand of the national economy and neighbouring countries.

Wind energy: Harnessing wind energy has not featured significantly in the country's energy economy to date, but awareness about this untapped resource is growing. Mozambique's wind energy resource is yet to be assessed in detail, but wind speeds of up to 6.8m/s at 30m height have already been measured in places along Mozambique's coast, indicating good potential for power generation. Inland wind speeds are generally less than 3 m/s (which is suitable for wind-driven mechanical water pumps), while along the main rivers and in proximities of major lakes (other than Lake Niassa) these can be expected to be around 4 m/s (KMPG, 2009).

Hydro energy: Mozambique's northern and central regions are rich in hydro-energy resources (both small-scale and large-scale), while the southern region has limited small-scale potential. The country has known hydropower potential of between 12 and 14 GW, with the majority of sites in the 'large-scale' range (>15 MW). Only some 2,500 MW have so far been developed, and a further 4,750 MW are in the planning stage (EDM, 2008). Little is known about the country's small-scale hydroelectric potential, which could play a significant role in meeting the energy needs of isolated communities.

Ocean energy: With a 2,800 km long coastline and a tidal range between 3 m and 7 m, (KMPG, 2009) Mozambique is believed to have good potential for ocean energy exploitation, but this has not yet been explored. Ocean energy includes wave energy, tidal energy, and ocean thermal energy.

Geothermal energy: The southern part of the African Rift Valley extends into Mozambique, and it is therefore possible that geothermal energy potential exists in the provinces of Niassa, Cabo Delgado, Tete, Manica, Sofala and Zambézia. This is yet to be explored, however (KMPG, 2009).

Figure 1 - Map of Mozambique (UN, 1998)

1.2 The Electricidade de Moçambique, E.P.

The Mozambique power utility, "Electricidade de Moçambique, E.P." (EDM), manages the bulk of the electricity distribution in Mozambique, it is also responsible for power generation facilities and transport infrastructures along the country, Figure 2 shows the electrical infrastructure. EDM is a government-owned public company that operates under a performance contract with the Government of Mozambique.

EDM's total installed generation capacity is nominally about 310 MW, of which the main part is diesel fuelled generation. Installed capacity of hydro power is the vicinity of 100 MW, of which 75 MW is currently available, distributed among the stations of Mavuzi (25), Chicamba (38) both in the central part of Mozambique and Corumana 12 MW in the south. Earlier there were small diesel/gas power stations scattered all over the country for provincial headquarters and other important towns. They are now replaced to a great extent by grid electricity through an extensive electrification program in addition to its own generation capacity.

EDM has three gas turbine units installed at Central Térmica Maputo (CTM), i.e. Maputo Power Station (71 MW) and one gas turbine installed in Beira main substation (14 MW). All units are fuelled by diesel and it is intended to carry out the CTM gas turbines conversion to burn natural gas.

It is planned to convey natural gas to Maputo city from an off take point (Ressano Garcia) in the Temane - South Africa gas pipeline.

1.3 Objectives

This assignment focuses on gas conversion of Maputo power plant, comprised of the following main equipment:

- Unit #1: Rolls Royce jet engine, with electrical output of 17000 kW.
- Unit #2: Sulzer BBC 11-B Gas Turbine, with electrical output of 29473 kW.
- Unit #3: GE-Alsthom Frame 5 Gas Turbine, with electrical output of 24504 kW.

This work focuses only on units #2 and #3, provided that the Rolls-Royce unit is out of order due to generator failure after the heavy floods of year 2000 that devastated the southern part of Mozambique.

The thesis general objectives are:

- Review gas turbines' cycles;
- Assess gas turbines' performance with different fuels.

The specific objectives are:

- Evaluate the conversion of Maputo Power Plant to burn natural gas;
- Propose modifications of the current power turbine cycles to combined cycle and steam-injected gas turbine;
- Select optimum cycle and propose its implementation.

1.4 Method of attack

The study is conducted as follows:

- assessment of current plant condition;
- plant performance analysis with diesel oil and conversion to natural gas;
- modification of current gas turbine cycle to steam injected gas turbine and combined cycle gas turbine;
    - sizing of HRSG;
    - sizing of steam turbine(s);

- steam-injected gas turbine system sizing;
- overall efficiency analysis for all proposed power generation cycles; and
- economic analysis for all proposed power generation cycles.

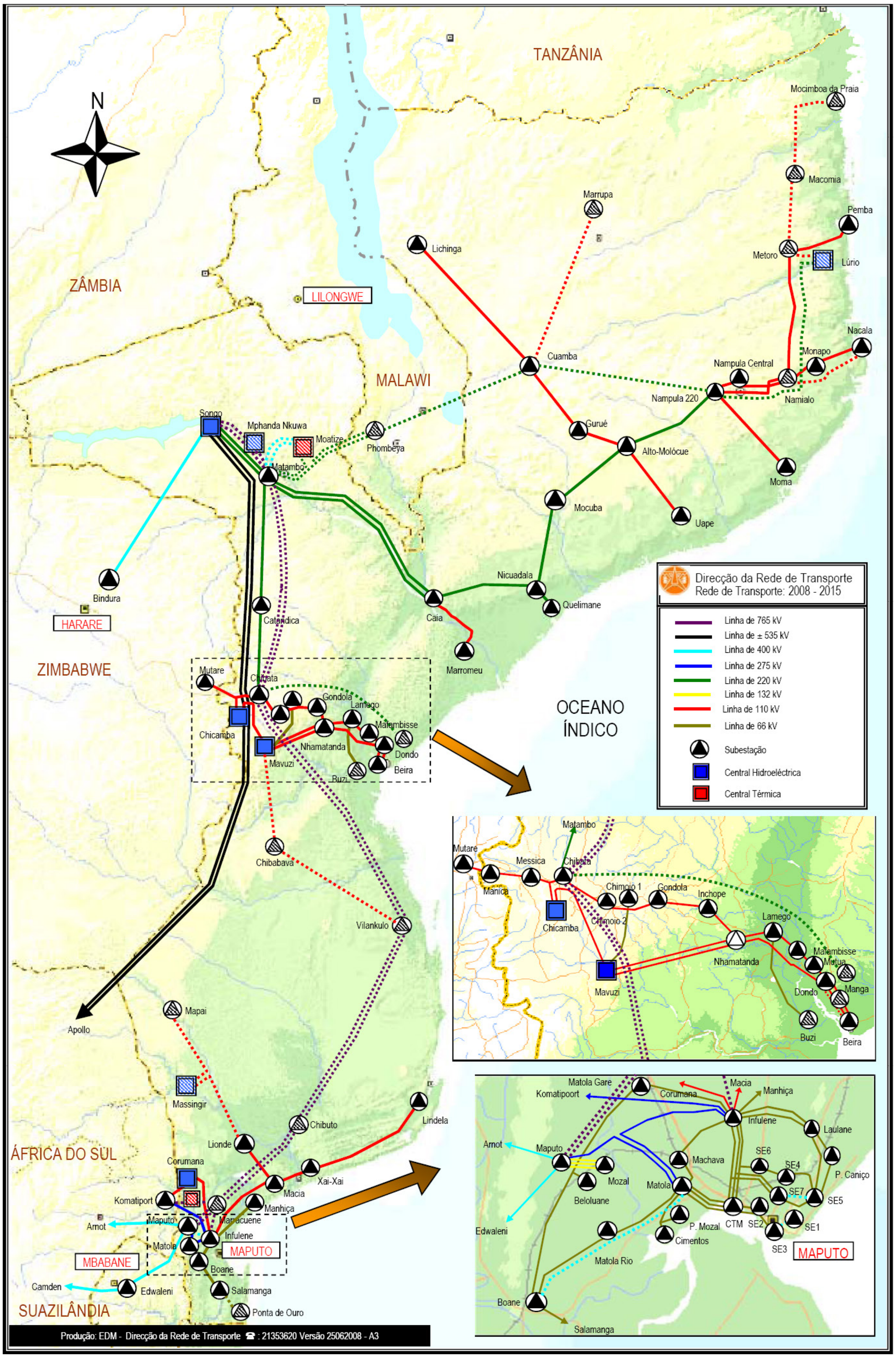

Figure 2 - Map of Mozambique with electrical network (EDM, 2008)

1.5 Thesis Structure

The report is divided in eight chapters, beginning with Chapter one, of the introduction, where the thesis project description and objectives are presented.

The treatise of the power plant facility is addressed in Chapter two.

Chapter three analyses the performance of the installed units in current operation mode, i.e., whilst fuelled with diesel oil.

Chapter four proposes converting the installed units to be fuelled by natural gas and presents performance analyses of the units on this mode of operation.

Chapter five proposes converting the installed units to be fuelled by natural gas, changes of the gas turbine cycle into steam injected gas turbine and presents performance analysis of the units with these assumptions.

Chapter six proposes converting the installed units to be fuelled by natural gas, changes the gas turbine cycle into combined cycle gas turbine and presents performance analyses of the units for the new cycle.

Chapter seven does the overall evaluation of proposed modifications, outlines the operability issues, assesses environmental impact and presents economic and financial analysis for each cycle.

Chapter eight discusses the study results and presents project conclusion and recommendations.

2 Plant description

Figure 3 below presents the power plant footprint.

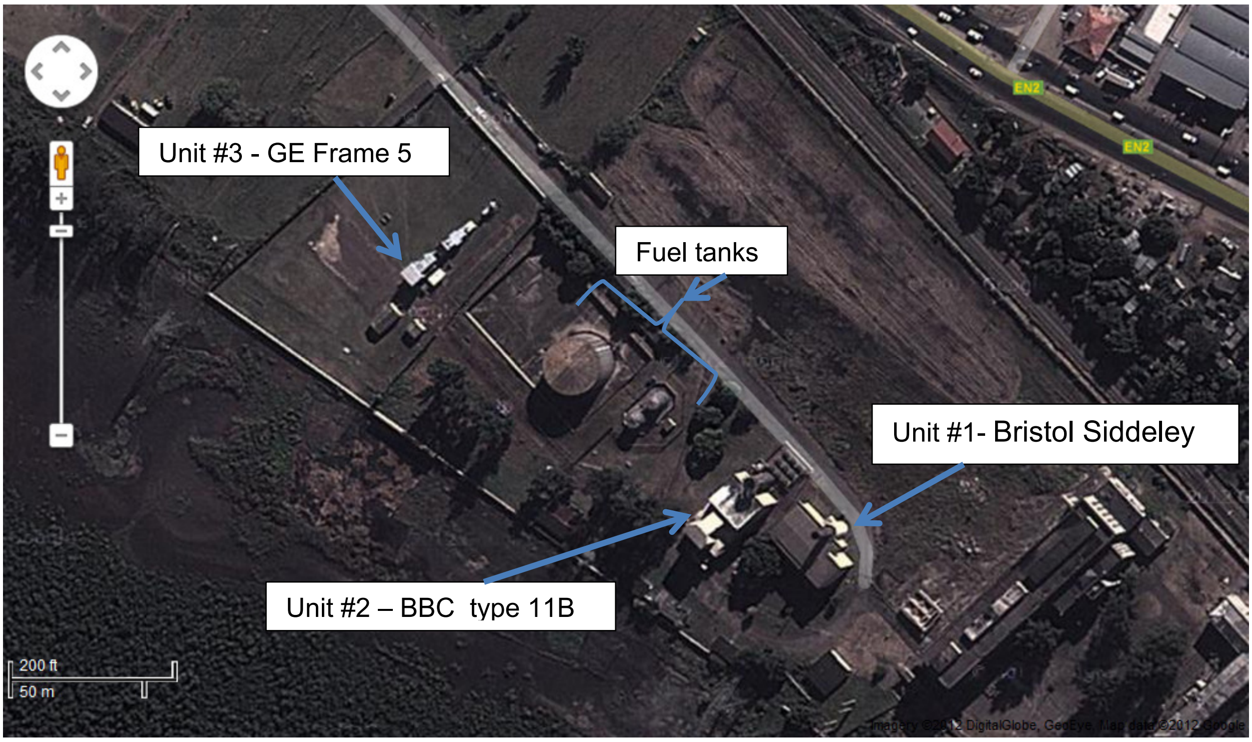

Figure 3 - Aerial view of Maputo power plant [Google maps photo]

2.1 Unit #1: Bristol Siddeley / GEC

The gas turbine of this unit was manufactured by Bristol Siddeley Engines Ltd (BSEL), a former British aero engine manufacturer, purchased by Rolls-Royce Limited in 1966, and the generator was built by The General Electric Company (GEC), a former major British-based industrial conglomerate, dedicated to defence electronics, communications and engineering.

The unit was installed in 1967 with a nominal capacity of 17.5 MW burning Jet Fuel. Due to engine failure, a new gas generator of this unit was installed in 1990 and operated only 60 running hours. The summary of the main data is presented in Table 1 and the schematic diagram of the gas turbine cycle is Figure 4.

Table 1 - Unit # 1 data

TECHNICAL DATA				
		Gas generator	Power turbine	Generator
Manufacturer		Bristol Siddeley	Bristol Siddeley	GEC
Model/type		BS 2006 m	BS olympus	
Nominal capacity	MW	17.5	-	26.25
Shaft speed	rpm	6615/8018	3000	3000
OPERATING AND MAINTENANCE DATA				
Manufacture year		1965		
Installation year		1967		

Total running hours	hrs	2020.3
Total number of starts		1223

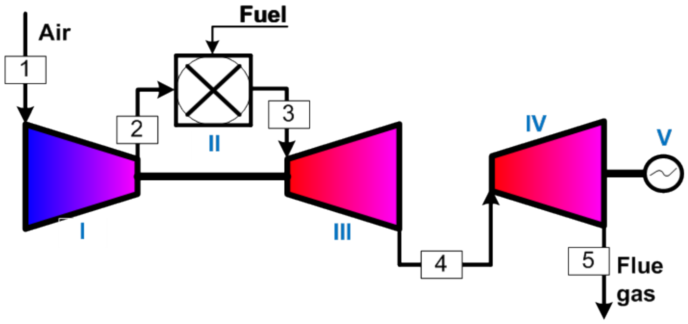

Figure 4 - Gas turbine cycle of unit #1

Legend:

I	Compressor
II	Combustion Chamber
III	High Pressure Gas Turbine
IV	Low Pressure Gas Turbine (Power Turbine)
V	Generator

Figure 5, bellow, shows the partial view of the installation.

Figure 5 - Site view of unit #1

2.2 Current status of the unit

The Bristol Siddeley / GEC unit was originally installed in 1967 with Olympus gas generator serial number 200618 and in 1990, due to low pressure compressor failure; it was replaced with Olympus gas generator serial number 200616. The installed gas generator recorded sixty two total operating hours since its installation.

The last time that the unit was in operation was in 1995. This is approximately seventeen years of a non-operation, what can be considered corresponding to 36,000 equivalent operating hours, when no corrosion inhibition is provided. Although the Olympus gas generator has only 62 operational running hours, the fact that the engine has been inactive for long period is a significant factor, too.

When Vattenfall Power Consultants AB inspected the unit in June 2009, the following findings have been reported (the author also took part in the team as project owner's engineer):

- Gas generator: minor corrosion was found on the inlet bell mouth, inlet guide vane and the first row of blades;
- Air intake system: the weather louvers are corroded; the static filter was dirty and damaged; the air channel is of a wrong design according to Alba inspection;
- Generator and exciter: damaged, flooded with water;
- Rotor: removed from stator and corroded;
- The following components are considered old fashioned (out of date) and should benefit from upgrading to today's standards:
  - Gas detection system;
  - Fire extinguishing system;
  - High voltage cubicle;
  - Generator circuit breaker;
  - Voltage regulator and protections;
  - Instrumentation: measuring equipment, indicators, recorders, printers;
  - Governing and control system; and
  - Low voltage equipment.

2.3 Unit #2: BBC Type 11-B

This unit was manufactured by Brown Boveri & Cie (BBC) a former Swiss group of electrical engineering companies. It was installed in 1974 with a nominal capacity of 36 MW burning diesel oil. The summary of the main data are presented in Table 2 and Figure 5 illustrates the schematic diagram of the gas turbine cycle.

Table 2 - Unit # 2 data

TECHNICAL DATA			
		Turbine	Generator
Manufacturer		Sulzer	BBC
Model/type		11-B	WT17L-052
Nominal capacity	MW	36	48.2
Shaft speed	rpm	3634	3000
OPERATING AND MAINTENANCE DATA			

Manufacture year		1973
Installation year		1974
Total running hours	hrs	8331.6
Total number of starts		986

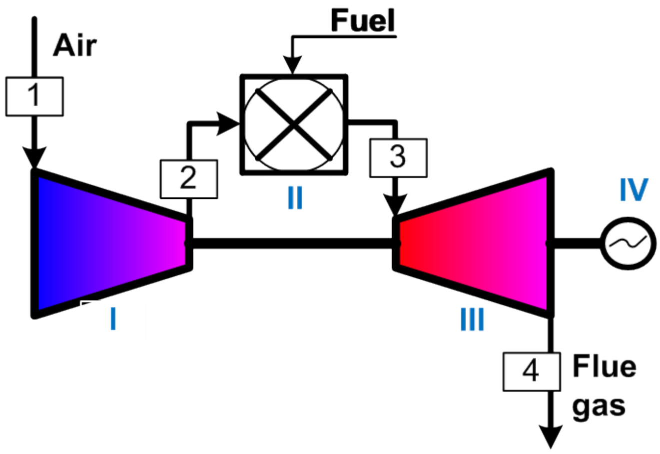

Figure 6 - Gas turbine cycle for units #2 and #3

Legend:

I	Compressor
II	Combustion Chamber
III	Gas Turbine
IV	Generator

Figure 7 shows the partial view of the installation

Figure 7 - Site view of unit #2

2.4 Current status of the unit

This unit has lain dormant for 12 years without no-corrosion inhibitors. When Vattenfall Power Consultants AB inspected the unit in June 2009, the following findings were reported:

- Compressor: the air intake duct had been flooded with water. Rust was observed on the inlet duct, bars, baffles, diffuser and guide vanes. The water level has been so high that the compressor has been submerged in water up to almost half the height of the first impellor row. The compressor must have been submerged to the same water level for a long period since the sign of the water level is marked as a deep as the rust line. Foreign objects were observed at the inlet of the compressor;
- Compressor bleed valves: water flushing through the valve from the compressor during start up(s);
- Compressor rotor blading: rust was observed on the first stage of blading below the water level mark. Rust was observed on the rotor;
- Exhaust and silencer: exhaust damper only functioning on half the stack area. Rust on the man hole hatch was observed;
- Measuring equipment: thermocouples exhaust dust corroded and difficult to remove;
- The following components are considered old fashioned (out of date) and should benefit from upgrading to today's standards:
  - Voltage regulator and protections;
  - Instrumentation: indicators, recorders;
  - Governing and control system; and
  - Low voltage equipment.

2.5 Unit #3: GE Frame 5

The unit #3 was manufactured by Alsthom in France, under the licence of General Electric Company (GE), an American multinational conglomerate corporation operating through four branches: Energy, Technology Infrastructure, Capital Finance and Consumer & Industrial.

It was installed in 1990 with a nominal capacity of 25 MW burning diesel oil. The summary of main data are presented in Table 3 and the schematic diagram of the gas turbine cycle is illustrated in Figure 6. Figure 8 shows the partial view of the installation.

Table 3 - Unit # 3 data

TECHNICAL SPECIFICATION			
		Turbine	Generator
Manufacturer		Alsthom	Alsthom
Model/type		MS 5001/P	T180-180Y
Nominal capacity	MW	25.8	22
Shaft speed	rpm	5120	3000
OPERATING AND MAINTENANCE DATA			
Manufacture year		1990	
Installation year		1992	
Total of running hours		373.3	
Total number of starts		130	

Figure 8 - Site view of unit #3

2.6 Current status of the unit

This is the unique unit available in the plant and is regarded as backup unit. When Vattenfall Power Consultants AB inspected the unit in June 2009, the following findings were reported:

- Compressor: small amount of oil detected at the compressor inlet;
- Air intake system/air channel: corroded enclosure roof structure;
- Combustion chamber: extension corrosion observed through external inspection(s);
- Building structure: frame basement flooded with rain water from corroded enclosure structure;
- Generator circuit breaker: corroded enclosure.

3 Plant Performance Analysis with Diesel Oil

The gas turbine cycle applicable for both units is depicted in Figure 6, chapter 2. A Microsoft Excel spread sheet was developed to calculate the plant performance.

3.1 Unit # 2, BBC Type 11-B

The following parameters were used to undertake the plant performance analysis with diesel oil:

- The fuel is diesel oil, with LHV of 42,330 kJ/kg and HHV of 45,467 kJ/kg at 25 °C. The calculations will approximate these figures.
- Compressor outlet temperature, T_2, is 308 °C, average from operating reading records,
- Compressor mass flow is 205.2 kg/s, as given by the manufacturer
- Compressor pressure ratio, π_c , is 7.5, as given by the manufacturer
- Turbine inlet temperature, T_3, is 840 °C, average from operating reading records
- Turbine exhaust temperature, T_4, is 445 °C, average from operating reading records
- Compressor inlet temperature, T_1, is 24 °C, operational readings;
- Compressor inlet pressure, p_1, is 1.013 bar, operational readings from site ambient barometric pressure;
- Combustion chamber pressure loss of 3 %, assumed;
- The overall mechanical efficiency, η_m, is 95%. Assumed figure, it includes gearbox and other mechanical losses;
- The overall electrical efficiency, η_{el}, is 95%. Assumed figure, it includes loss in generator, power consumption for cooling, lubrication and control systems.

The detailed calculation sheet is presented in Appendix I and the results are shown in Table 4 below.

Table 4 - Unit #2 gas turbine data whilst fuelled by diesel oil

<table>
<tr><td>Compressor:
• $\dot{m}_{air} = 205.2$ [kg/s]
• $\eta_{SK} = 80$ [%]
• $\pi_c = 7.50$
• $T_2 = 308$ [°C]
• $P_c = 60$ [MW]</td><td>Combustion chamber
• $\dot{m}_{fuel} = 3.01$ [kg/s]
• $LHV = 42$ [MJ/kg]
• $HHV = 45$ [MJ/kg]
• Fuel injection temperature 25 °C</td></tr>
<tr><td rowspan="2">Gas turbine
• $T_3 = 841$ [°C]
• $p_3 = 7.37$ [bar]
• $T_4 = 445$ °C
• $\pi_t = 7.28$
• $\eta_{ST} = 91$ [%]
• $\eta_m = 95$ [%]
• $P_T = 95$ [MW]
• $\dot{m}_{fluegas} = 208.21$ [kg/s]</td><td>Gas turbine generator
• $P_{GTel} = 29$ [MW]
• $\eta_{el} = 95$ [%]</td></tr>
<tr><td>Gas turbine cycle overall efficiency
• $\eta_{GTel} = 22.63$ [%]</td></tr>
</table>

3.2 Unit # 3, GE Frame 5

The performance analysis for unit # 3, GE Frame 5, uses the same philosophy and equations used for unit # 2, BBC Type 11-B. The following parameters were used to undertake the plant performance analysis with diesel oil:

- The fuel is diesel oil, with LHV of 42,330 kJ/kg and HHV of 45,467 at 25 °C. The calculations will approximate these figures;
- Compressor outlet temperature, T_2, is 325 °C, average from operating reading records;
- Compressor pressure ration, πc, is 10.2, as given by manufacturer;
- Combustion chamber fuel mass flow is 2.12 kg/s, as given by manufacturer;
- Turbine inlet temperature, T_3, is 946 °C, average from operating reading records;
- Turbine exhaust temperature, T_4, is 487°C, average from operating reading records;
- Gas turbine cycle flue gas mass flow is 122.22 kg/s, as given by manufacturer.
- Compressor inlet temperature, T_1, is 25.5 °C, unit operational readings inlet temperature;
- Compressor inlet pressure, p_1, 1.013 bar, unit operational readings inlet pressure, site ambient site barometric pressure
- Combustion chamber pressure loss of 3 %, assumed;
- The overall mechanical efficiency, η_m, is 95 %. Assumed. It includes gearbox losses and other mechanical losses;
- The overall electrical efficiency, η_{el}, is 95 %. Assumed, it includes loss in generator, power consumption for cooling, lubrication and control systems.

The detailed calculation sheet is presented in Appendix I and the results are shown in Table 5 below.

Table 5 - Unit #3 gas turbine data whilst fuelled by diesel oil

Compressor: • $\dot{m}_{air} = 120.10$ [kg/s] • $\eta_{SK} = 92$ [%] • $\pi_c = 10.20$ • $T_2 = 325$ [°C] • $P_c = 37$ [MW]	Combustion chamber • $\dot{m}_{fuel} = 2.12$ [kg/s] • $LHV = 42$ [MJ/kg] • $HHV = 45$ [MJ/kg] • Fuel injection temperature 25 [°C]
Gas turbine • $T_3 = 948$ [°C] • $p_3 = 10.02$ [bar] • $T_4 = 483$ [°C] • $\pi_t = 9.89$ • $\eta_{ST} = 88$ [%] • $\eta_m = 95$ [%] • $P_T = 66$ [MW] • $\dot{m}_{fluegas} = 122.22$ [kg/s]	Gas turbine generator • $P_{GTel} = 25$ [MW] • $\eta_{el} = 95$ [%] Gas turbine cycle overall efficiency • $\eta_{GTel} = 27.79$ [%]

4 Expected Plant Performance Analysis with Natural Gas

As the gas conversion project targets unit #2 and unit #3, the performance analysis with natural gas will focus on these two units, only.

Converting the installed units to run with natural gas requires installing new combustion chambers and new gas fuel nozzles. Other major equipment such as compressor, gas turbine and generator would remain the same. Gas piping hardware interface with the existing units is dealt in details in this report.

The gas turbine cycle used for calculations and applicable for both units is depicted in Figure 6 (chapter 2) and data from plant performance analysis with diesel oil are used (chapter 3). A Microsoft Excel spread sheet (Appendix II) was created to calculate the plant performance.

The calculations are approximated with the tables and diagrams that are used for gases from light oil combustion.

The following general parameters were used to undertake the plant performance analysis with natural gas:

- The fuel is natural gas, with LHV of 47,587 kJ/kg and HHV of 50,496 kJ/kg at 25 °C. The calculations will, again, approximate these figures;
- Combustion chamber pressure loss of 2%, assumed;
- The overall mechanical and electrical efficiencies are same as for diesel oil calculations; and
- The isentropic exponent for flue gas as well as the isentropic efficiency for turbines are the same as for diesel oil calculations; and
- Turbine output power for natural gas is the same as for diesel oil results.

4.1 Unit # 2, Sulzer BBC 11-B

The calculation results for unit #2 are summarised in Table 6 below.

Table 6 - Unit #2 gas turbine data whilst fuelled by natural gas

<table>
<tr><td>Compressor:
• $\dot{m}_{air} = 205.2$ [kg/s]
• $\eta_{SK} = 80$ [%]
• $\pi_c = 7.50$
• $T_2 = 308$ [°C]
• $P_c = 60$ [MW]</td><td>Combustion chamber
• $\dot{m}_{fuel} = 2.67$ [kg/s]
• $LHV = 48$ [MJ/kg]
• $HHV = 51$ [MJ/kg]
• Fuel injection temperature 25 °C</td></tr>
<tr><td rowspan="2">Gas turbine
• $T_3 = 841$ [°C]
• $p_3 = 7.446$ [bar]
• $T_4 = 449$ °C
• $\pi_t = 7.28$
• $\eta_{ST} = 91$ [%]
• $\eta_m = 95$ [%]
• $P_T = 95$ [MW]
• $\dot{m}_{fluegas} = 207.17$ [kg/s]</td><td>Gas turbine generator
• $P_{GTel} = 29$ [MW]
• $\eta_{el} = 95$ [%]</td></tr>
<tr><td>Gas turbine cycle overall efficiency
• $\eta_{GTel} = 22.80$ [%]</td></tr>
</table>

4.2 Unit #3, GE Frame 5

The calculation results for GE Frame 5 are presented in Table 7 below.

Table 7 - Unit #3 gas turbine data whilst fuelled by natural gas

Compressor: • $\dot{m}_{air} = 120.10$ [kg/s] • $\eta_{SK} = 92$ [%] • $\pi_c = 10.10$ • $T_2 = 325$ [°C] • $P_c = 37$ [MW]	Combustion chamber • $\dot{m}_{fuel} = 1.87$ [kg/s] • $LHV = 48$ [MJ/kg] • $HHV = 51$ [MJ/kg] • Fuel injection temperature 25 °C
Gas turbine • $T_3 = 948$ [°C] • $p_3 = 10.13$ [bar] • $T_4 = 483$ °C • $\pi_t = 10$ • $\eta_{ST} = 88$ [%] • $\eta_m = 95$ [%] • $P_T = 66$ [MW] • $\dot{m}_{fluegas} = 121.97$ [kg/s]	Gas turbine generator • $P_{GTel} = 25$ [MW] • $\eta_{el} = 95$ [%] Gas turbine cycle overall efficiency • $\eta_{GTel} = 28.09$ [%]

5 Expected Plant Performance Analysis with Steam Injection Gas Turbine (STIG)

As the gas conversion project targets unit #2 and unit #3, the performance analysis with steam injection will focus these two units, only.

The gas turbine cycle used for calculations and applicable for both units is depicted in Figure 9, below.

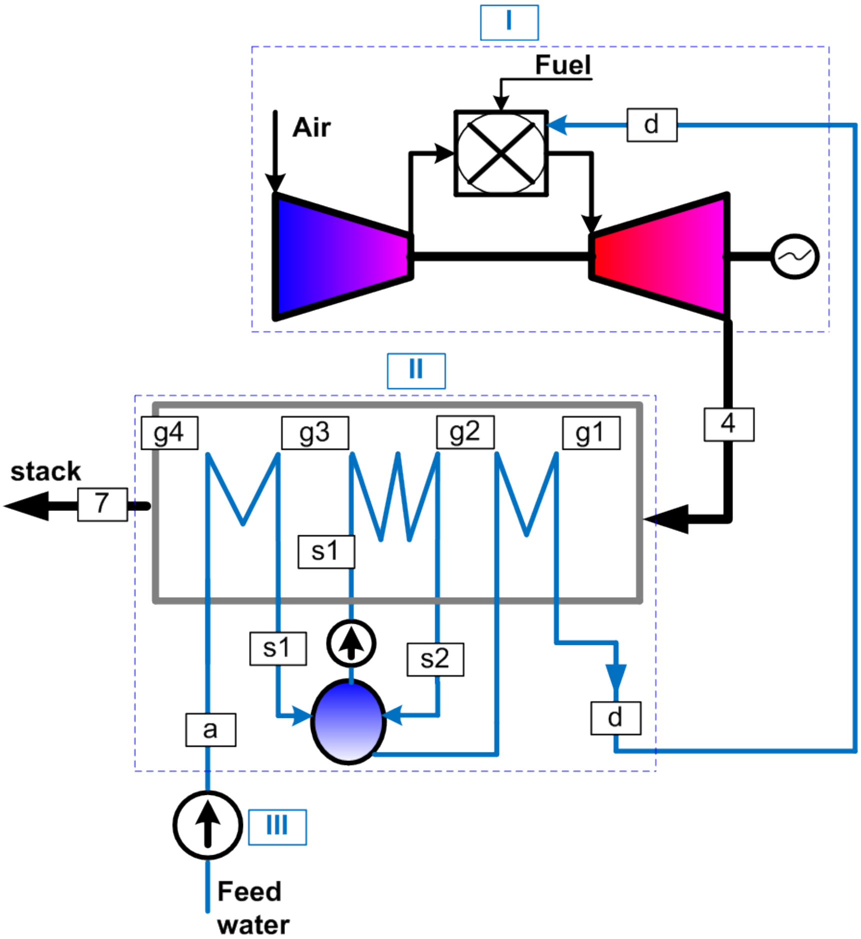

Figure 9 - Steam Injected Gas Turbine Cycle, STIG (CompEdu)

Legend:

I Conventional Gas Turbine Cycle

II Heat Recovery Steam Generator (HRSG), refer to chapter 6 for details

III Feed Water Pump

The calculations are approximated with the tables and diagrams that are used for gases from light oil combustion. A Microsoft Excel spread sheet (Appendix III) was created to calculate the plant performance with STIG.

The following general parameters were used to undertake the plant performance analysis with STIG:

- The fuel is natural gas, with LHV of 47,587 kJ/kg and HHV of 50,496 kJ/kg at 25 °C. The calculations will, again, approximate these figures.
- Since the steam is injected into combustion chamber, the compressor remains unaffected by the steam injection;
- The overall mechanical and electrical efficiencies are same as without steam injection;
- The isentropic exponent for the flue gas as well as the isentropic efficiency for the turbines are the same as without steam injection;
- The fuel control system maintains the turbine inlet temperature at a constant value (which means that the fuel flow must increase a little to heat the injected steam up to the turbine inlet temperature);
- The turbine inlet pressure remains the same as without steam injection;
- The gas turbine outlet pressure remains the same as without the HRSG; and
- HRSG feed water temperature, T_a, is 26 °C, (the average site ambient temperature).

5.1 Discussions on Steam Injection Gas Turbine Cycle

Modifying the existing units into STIG increases the power output and the overall electrical efficiencies. However, the capacities of the installed equipment limit harnessing the full power. The unit #2 can generate up to 36.00 MW but is limited to 29 MW due to step up transformer. By introducing STIG cycle the calculations (see spread sheet on Appendix III) give an output of 54.00 MW for unit #2, with steam mass flow of 15% of compressor air flow. Similarly, the maximum power output from the unit #3 is 25.00 MW while the STIG cycle gives an output of 44.00 MW.

The project scope includes converting the gas turbines to run on natural gas, and to improve the plant efficiency by modifying the existing gas turbine cycles to STIG or into combined cycle, without uprating the installed equipment.

As the calculated results give higher values than installed capacities, additional analyses have to be made in order to optimise the STIG cycle for the installation. This involves matching the STIG power output to installed capacities by varying the superheat steam parameters, namely: mass, pressure and temperature.

By keeping constant the superheated steam flow and varying the pressure, temperature and both pressure and temperature the results show that there is slight change in the STIG power output, as plotted in the Table 8.

Table 8 - Unit #2 STIG analysis for steam mass flow of 15% of compressor air flow

$\dot{m}_{st}$ [kg/s]	30.78	30.78	30.78	30.78	30.78	30.78	30.78
$T_{d,st}$ [°C]	200	200	410	410	410	650	650
$p_{d,st}$ [bar]	4.00	8.00	4.00	8.00	12.00	8.00	12.00
$\dot{m}_{fuel}$ [kg/s]	3.62	3.63	3.32	3.32	3.33	2.97	2.97
P_{STIGel} [kW]	54.02	54.04	53.68	53.69	53.69	53.28	53.28
η_{STIGel} [%]	31.40	31.28	33.98	33.94	33.90	37.72	37.70
T_7 [°C]	145	151	98	102	103	39	37

The table above shows also that the efficiency of a STIG cycle increases as the superheat steam temperature increases, resulting also into low stack temperatures.

To match the STIG power output to installed generator capacities at Maputo Power Plant, the steam mass flow should be lower than 15% of compressor air flow.

Calculations for unit #2, see Table 9, show that to get a STIG electrical power output of 29.00 MW only 0.41 kg/s of steam can be injected, which represents 0.2% of compressor air flow.

Table 9 - Unit #2 STIG analysis for steam mass flow of 0.2% of compressor air flow

$\dot{m}_{st}$ [kg/s]	0.41	0.41	0.41	0.41	0.41	0.41
$T_{d,st}$ [°C]	200	200	410	410	410	650
$p_{d,st}$ [bar]	4.00	8.00	4.00	8.00	12.00	8.00
$\dot{m}_{fuel}$ [kg/s]	2.68	2.68	2.68	2.68	2.68	2.67
P_{STIGel} [kW]	28.90	28.90	28.89	28.89	28.89	28.89
η_{STIGel} [%]	22.64	22.64	22.67	22.67	22.67	22.70
T_7 [°C]	440	440	439	439	439	438

Table 9 shows also that the efficiency of a STIG cycle decreases as the steam mass flow decreases, resulting also into high stack temperatures.

The results above show that applying STIG cycle to unit #2 without uprating the generator is not worth, as the unit electrical efficiency increases only slightly.

However, finding the optimum superheat mass flow to match the STIG power output to installed generator capacity was performed.

Results for unit #3, see Table 10, show that to match the STIG cycle power output to installed equipment capacity the mass flow of superheat steam should be nearly zero per cent of compressor air flow. With only 0.08 kg/s of steam the STIG cycle for unit #3 can generate 25 MW.

Table 10 - Unit #3 STIG analysis for different steam mass flow

$\dot{m}_{st}$ as % of $\dot{m}_{air}$	15	1	0.5	0.25	0.125	0.0625
$\dot{m}_{st}$ [kg/s]	18.02	1.20	0.60	0.30	0.15	0.08
$T_{d,st}$ [°C]	440	440	440	440	440	440
$p_{d,st}$ [bar]	11.00	11.00	11.00	11.00	11.00	11.00
$\dot{m}_{fuel}$ [kg/s]	2.33	1.90	1.88	1.87	1.87	1.87
P_{STIGel} [MW]	42.55	26.05	25.46	25.17	25.02	24.95
η_{STIGel} [%]	38.39	28.86	28.44	28.22	28.12	28.06
T_7 [°C]	137	455	469	476	479	481

In conclusion, both units #2 and #3 do not support cycle modification to STIG cycle.

6 Expected Plant Performance Analysis with Combined Cycle Gas Turbine

As the gas conversion project targets the unit #2 and #3, performance analysis for combined cycle will be done for these units only.

6.1 The Combined Cycle Gas Turbine

As widely known, combined cycles are comprised of conventional gas turbine and steam turbine cycles, where the heat exhausted from the gas turbine is re-used to generate steam in the heat recovery steam generator (HRSG). Figure 7 depicts a typical gas turbine combined cycle.

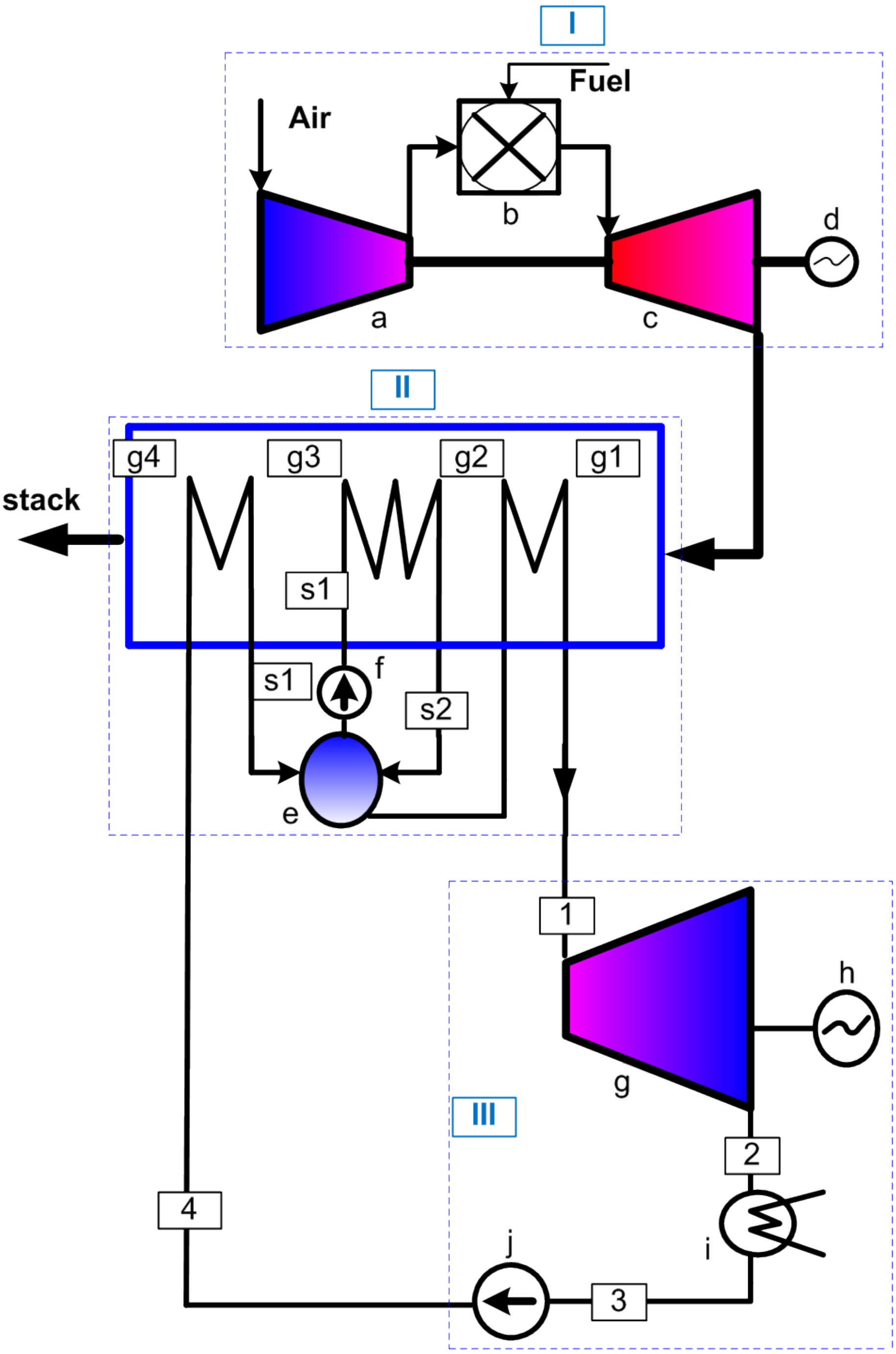

Figure 10 - Gas Turbine Combined Cycle, CCGT (CompEdu)

Legend:

I	Conventional Gas Turbine Cycle	a	Compressor
II	Heat Recovery Steam Generator (HRSG)	b	Combustion Chamber
III	Conventional Steam Turbine Cycle	c	Gas Turbine
		d	Gas Turbine Cycle Generator
		e	HRSG de-aerator drum
		f	HRSG circulating pump
		g	Steam Turbine
		h	Steam Turbine Cycle Generator
		i	Condenser
		j	Feed Water Pump

The gas turbine is hence the most important component in the combined gas-steam cycle, provided that the steam cycle utilizes the exhaust heat from the gas turbine by means of a heat recovery steam generator (HRSG).

The HRSG can be designed without additional firing, where all the fuel is burned in the gas turbine, or equipped with supplementary firing, where additional fuel is mixed with the gas turbine exhausts to increase temperature and produce more steam.

The supplementary firing gives higher steam cycle power output, thanks to higher amount of steam that can be produced, but does not increase the combined gas-steam efficiency since the supplied fuel is only used in the steam cycle.

Relating to pressure levels, the HRSG can be of single pressure or of multi-pressure. More heat from the exhaust gas can be recovered to the steam cycle, if several pressure levels in the steam cycle are introduced. A multi-pressure level reduces the exergy losses in the HRSG and provides lower stack temperatures, although each pressure level increases the cost of the installation (Kehlhoffer, 1997).

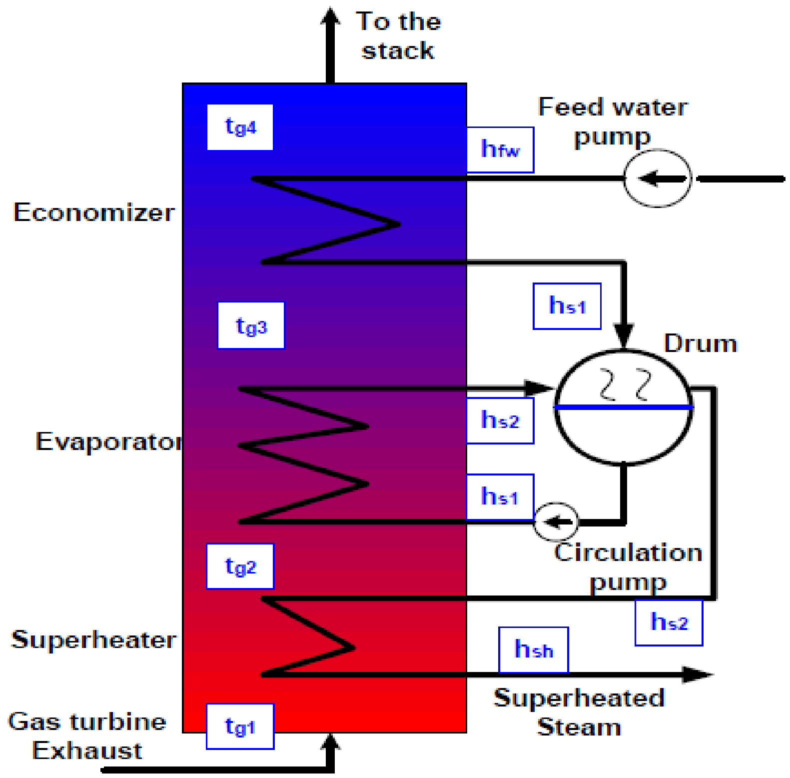

Figure 11 - Heat Recovery Steam Generator, HRSG (CompEdu)

The single pressure is the simplest arrangement of a HRSG and comprises the economizer, the evaporator and the super-heater, as illustrated in Figure 11 and Figure 12.

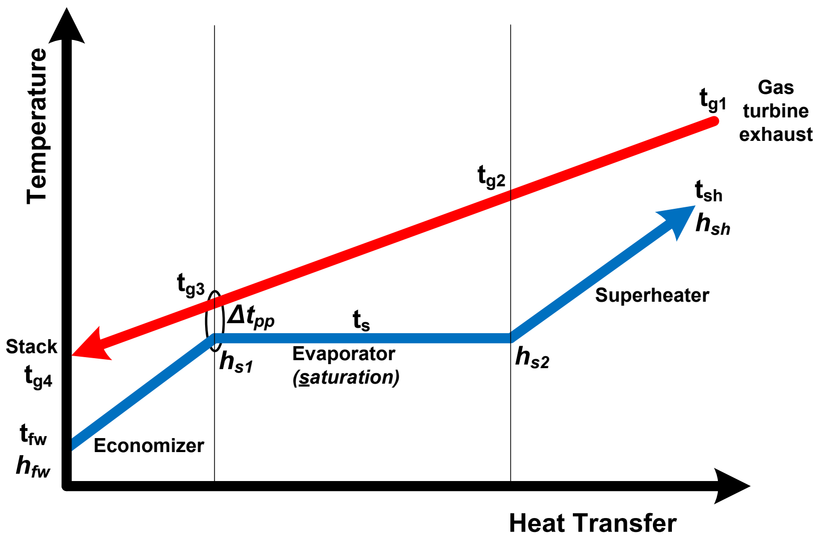

Figure 12 - Single pressure HRSG heat transfer diagram (CompEdu)

A single pressure HRSG without supplementary firing is employed in this project work.

When designing an optimum HRSG cost and heat gain should be taken into account. An important parameter to design the HRSG is the pinch point temperature difference, Δt_{PP}, the difference between the evaporator exhaust gas temperature, t_{g3}, and the temperature of water evaporation, t_s.

The pinch point temperature is usually between 5ºC and 15ºC. The lower the pinch point temperature difference, the higher the cost for the heat exchanger (CompEdu). This project uses the average figure, i.e. the pinch point temperature of 10 °C will be used for the combined cycle analysis.

Therefore, in order to harness heat from HRSG, the stack temperature should be above 100 °C, as at this temperature level condensation may occur. The present project designs the HRSG with initial stack temperature of 120 °C, the accurate figure will be found by iterations.

The steam turbine used for combined cycle should be of higher efficiency for the purpose of harnessing the energy from the steam, since the gas turbine is already given as a standard machine.

The most important design parameter of a steam turbine is the steam data, i.e. the mass flow and the steam turbine input pressure and temperature, as well as the condenser pressure.

In a combined-cycle plant, a high live pressure does not necessarily mean high efficiency. It is striking that the best efficiency is attained even while the live pressure is quite low. The overall efficiency of the steam turbine process is the product of rate of energy utilisation and the efficiency of water/steam cycle. There is an optimum at approximately 30 bar for single-pressure systems (Kehlhoffer, 1997).

However, raising the live steam temperature always brings about a slight increase in efficiency. The temperature of the gas turbine exhaust provides the upper limit of the live steam temperature. It is important to highlight that the gas turbine exhaust temperature, t_{g1}, is higher than the steam turbine inlet temperature, t_1.

A temperature gradient of 20 °C between the gas turbine exhaust and steam turbine inlet is used in this project work.

As the proposed combined cycle is in power generation industry, a condensing steam turbine is employed where the exhaust steam is partially in condensed state at pressure below the atmospheric pressure.

Typical steam turbine outlet pressure in condensing mode ranges from 0.03 to 0.25 bar [2]. As average figures are used, the current work takes the steam turbine outlet pressure of 0.1 bar.

The Maputo Power Plant performance analysis with combined cycle involves designing, for each installed unit, the corresponding steam turbine, steam turbine generator, condenser and the HRSG.

A common HRSG for both units would lower the project's costs, but this option is not considered in this project work, as the two units are installed 140 metres from each other, what would cause pressure losses and hence lowering the overall efficiency.

To find the steam turbine that together with the installed gas turbine, fuelled by natural gas, form a combined gas turbine, the steam parameters have to be found a prior.

Since the steam turbine parameters are unknown, the performance analysis assumes, according to previous assumptions, the steam turbine inlet pressure and temperature to calculate the steam mass flow.

In this assignment, the steam turbine and HRSG designing process starts by assuming the figures for steam turbine inlet temperature, the steam turbine outlet pressure, the pinch point temperature difference and iterating the steam turbine inlet pressure.

The steam turbine generator and condenser will be designed after selecting the combined cycle steam turbine. The HRSG is designed in conjunction with the steam turbine since the steam turbine inlet is the HRSG exhaust.

The calculations are approximated with the tables and diagrams that are used for gases from light oil combustion.

The following parameters were used to undertake the combined cycle plant performance analysis:

- The fuel is natural gas, with LHV of 47,587 kJ/kg and HHV of 50,496 kJ/kg at 25 °C. The calculations will approximate these figures;
- The pinch point temperature difference, Δt_{pp} , is 10 °C;
- A temperature gradient between the gas turbine exhaust, t_{g1}, and the steam turbine inlet, t_1, is 20 °C;
- The steam turbine outlet pressure is 0.1 bar;

The combined cycle used for calculations and applicable for proposed modifications is depicted in Figure 11 and Figure 12.

6.2 Unit # 2, BBC Type 11-B

In order to determine the combined cycle components, all parameters are to be calculated. Applying the calculation sheet (see appendix IV) the following results were obtained.

Table 11 - Unit #2 combined cycle analysis

p_1 [bar]	m_{st} [kg/s]	P_{ST} [MW]	P_{STel} [MW]	P_{CCel} [MW]	η_{ccel} [%]	t_{g4} [°C]	m_{water} [kg/s]
80.00	16.72	16.54	16.21	45.06	35.47	219.35	802.74
70.00	17.19	17.00	16.66	45.51	35.82	211.48	832.63
60.00	17.71	17.32	16.98	45.83	36.07	202.82	869.68
50.00	18.30	17.65	17.30	46.15	36.32	193.16	911.72
40.00	18.98	17.94	17.58	46.43	36.54	182.17	961.63
30.00	19.78	18.15	17.79	46.64	36.71	169.28	1022.59
20.00	20.79	18.19	17.82	46.67	36.74	153.25	1104.46
10.00	22.24	17.70	17.35	46.20	36.36	130.62	1232.11
5.00	23.42	16.68	16.35	45.20	35.57	112.54	1349.05
2.50	24.39	15.28	14.97	43.82	34.49	97.88	1457.73

The table above shows that the highest efficiency is attained at steam pressure of 20 bar.

It was previously stated that converting the installed unit to run with natural gas on combined cycle mode would require the installation of new additional components, while the compressor, gas turbine and the gas turbine generator remain unchanged.

The new equipment to accommodate the fuel conversion and combine cycle components are the natural gas fuel nozzles, HRSG, steam turbine system (including condenser) and the steam turbine electrical generator and balance of system.

The details and technical specifications for new equipment are described in Table 12.

Table 12 – Steam cycle for unit #2 combined cycle

HRSG	Steam Turbine
• Stack temperature, $t_{g4} = 153$ °C • $t_s = 212$ °C • $\Delta t_{pp} = 10$ °C	• $t_1 = 425$ [°C] • $p_1 = 20$ [bar] • $\eta_{is} = 88$ % • $\eta_m = 98$ % • $\mathrm{P_{st}} = 18.19$ [MW] • $\dot{m}_{st} = 20.79$ [kg/s] • $p_2 = 0.10$ [bar]
Steam turbine generator	**Overall combined cycle analysis**
• $\mathrm{P_{STel}} = 17.82$ [MW] • $\eta_{el} = 98$ %	• $\mathrm{P_{CCel}} = 46.67$ [MW] • $\eta_{\mathrm{ccel}} = 36.74$ [%]
Condenser cooling water parameters	
• $\dot{\mathrm{m}}_{\mathrm{water}} = 1104$ kg/s • $t_{in} = 26$ °C • $t_{out} = 36$ °C	

6.3 Unit #3, GE Frame 5

The performance analysis for combined cycle of unit # 3, GE Frame 5, will use same philosophy and equations as for unit # 2, BBC Type 11-B. The calculation details are plotted in appendix IV, and the result summary is presented in Table 13.

Table 13 - Unit #3 combined cycle analysis

p_1 [bar]	m_{st} [kg/s]	P_{ST} [MW]	P_{STel} [MW]	P_{CCel} [MW]	η_{ccel} [%]	t_{g4} [°C]	m_{water} [kg/s]
80.00	11.93	12.46	12.21	37.15	41.84	201.12	585.36
70.00	12.15	12.58	12.32	37.27	41.97	194.56	602.53
60.00	12.39	12.68	12.42	37.37	42.08	187.23	622.46
50.00	12.67	12.77	12.52	37.46	42.19	178.98	645.32
40.00	13.00	12.84	12.58	37.53	42.26	169.48	672.68
30.00	13.40	12.85	12.59	37.54	42.27	158.20	706.71
20.00	13.91	12.72	12.47	37.41	42.13	144.01	752.80
10.00	14.65	12.23	11.99	36.93	41.59	123.73	825.98
5.00	15.26	11.45	11.22	36.17	40.73	107.44	894.01
	15.76	10.47	10.26	35.21	39.65	94.17	957.78

The table above shows that the highest efficiency is attained at a steam pressure of 30 bar.

It was previously stated that converting the installed unit to run with natural gas on combined cycle mode would require the installation of new additional components, while the compressor, gas turbine and the gas turbine generator remain unchanged.

The newly installed equipment to accommodate the fuel conversion and combined cycle are the natural gas fuel nozzles, HRSG, steam turbine system (including condenser) and the steam turbine electrical generator.

The details and technical specifications for new equipment of unit #3 are described in Table 14.

Table 14 - Steam cycle for unit #3 combined cycle

HRSG • Stack temperature, $t_{g4} = 158$ °C • $t_s = 234$ °C • $\Delta t_{pp} = 10$ °C	Steam Turbine • $t_1 = 463$ [°C] • $p_1 = 30$ [bar] • $\eta_{is} = 88$ % • $\eta_m = 98$ % • $\mathrm{P_{st}} = 12.85$ [MW] • $\dot{m}_{st} = 13.40$ [kg/s] • $p_2 = 0.10$ [bar]
Steam turbine generator • $\mathrm{P_{STel}} = 12.59$ [MW] • $\eta_{el} = 98$ %	Overall combined cycle analysis • $\mathrm{P_{CCel}} = 37.54$ [MW] • $\eta_{\mathrm{ccel}} = 42.27$ [%]
Condenser cooling water parameters • $\dot{\mathrm{m}}_{\mathrm{water}} = 707$ kg/s • $t_{in} = 26$ °C • $t_{out} = 36$ °C	

7 Plant Operability Analysis

The current general status of the Maputo power plant is technologically obsolete and does not fulfil nowadays operation and maintenance safety requirements. The majority of plant components are no longer available on the market and the manufactures are unable to provide full support.

In addition, due to technical obsolescence, difficulties to get spares for the old systems could also be experienced.

Thus, lots of measures are necessary to be taken in order to have the plant fully operational, this includes replacing and/or upgrading the plant components and operation philosophy.

The Maputo power plant operability analysis includes the following:

- Plant re-commissioning using the current fuel;
- Plant conversion to run on natural gas; and
- Plant modification to combined gas turbine cycle running on natural gas.

The following sections outline the required work to put the plant in operation using the plant operability options.

7.1 Plant Re-commissioning with current fuel

7.1.1 Re-commissioning of unit #1 with Jet fuel

This unit is currently installed to run with Jet A1 fuel and is in stand still since 1995, when it was operated for the last time. During its operation, it had power output limitation to 10 MW due to air intake design that allowed cooling while a non-cooled air intake was installed. This issue is to be taken into account when re-commissioning the unit, in order to harness its full potential.

In order to have the unit running on current fuel, the following measures are necessary, as described by Vattenfall Power Consultants AB draft inception report (Vatenfall, 2009):

Air intake: The intake channel has to be rebuilt and extended to enable full load operation. This includes analysing the cooling versus non-cooled air intake options. The current weather lowers and air intake filters have to be replaced.

Gas generator: The Olympus gas generator, what includes compressor, combustion chamber and the high pressure gas turbine should be removed from site and send to a service company for inspection and servicing.

Power turbine: The power turbine is to be refurbished. The major refurbishment includes a completely volute remanufacturing. All pumps and motors are to be refurbished, the rotor blades are to be removed and crack tested and the rotor balanced. All welds are subjected to magnetic particle inspection to verify their integrity, all instrumentation panels refurbished and the oil tank repaired, shot blasted and painted with heat protected paint.

Fuel system: The fuel control package including filters and servo valves that need to be overhauled. The high pressure fuel pump mounted on the gas generator and direct driven will be overhauled in the workshop as part of the gas generator service.

Electrical system: The following activities are suggested to be implemented with regards to the electrical system:

- The alternator stator core windings and the rotor windings insulation have to be checked and replaced, if the insulation is unsatisfactory;
- The exciter must be overhauled;
- Alternator rotor insulation resistance must be checked;

- Checking of stator and rotor wedges;
- Replacement of repair of alternator bearings and oil seals as required;
- Clean and paint the package enclosure;
- Calibration of pressure and temperature instrumentation;
- Check generator cornet transformers (CT's) and voltage transformers (VT's);
- Replacement of alternator rotor end ring;
- The alternator circuit breaker must be overhauled;
- The high voltage cubicle including automatic voltage regulator (AVR), generator control panel (GCP) is proposed to be replaced by an updated system;
- The local panel cubicles, low voltage switchboards gears, motor control centre (MCC) are recommended to be replaced; and
- The uninterrupted power supply (UPS) and rectifiers are proposed to be replaced by an updated system.

Control system: Recommended to be replaced by an updated system, including the digital turbine governor.

Auxiliaries: The following activities are suggested to be implemented with regards to the auxiliaries:

- The fire extinguishing system and gas detection system must be replaced;
- The coolers to be overhauled and cleaned; and
- The lubrication oil system to be refurbished.

When Vattenfall Power Consultants AB inspected the unit in June 2009, the author took part in the team as the project owner's engineer.

7.1.2 Re-commissioning of unit #2 with diesel oil

The current technical condition of the installation allows the unit to run on diesel oil only. Although the BBC Type 11-B unit did not achieve the necessary operating hours for a major overhaul, the fact that is being in long stand still period without adequate corrosion protection, a major overall is to be considered.

In order to have the unit running on current fuel, the following measures are necessary, as described by Vattenfall Power Consultants AB draft inception report (Vatenfall, 2009):

Air intake: The air inlet housing and intake duct need to be cleaned up.

Compressor: The outer casing is to be disassembled for visual inspection and non-destructive testing of the stator, guide vanes and rotor blading. Visual and magnetic testing / ultrasonic testing of rotor should also be taken.

Power turbine: Disassembling of turbine outer casing for visual inspection and non-destructive testing of the stator, turbine blading and guide vanes.

Combustion chamber: Disassembling for visual inspection and non-destructive. Visual inspection of fuel injector is also to be considered.

Exhaust and silencer: Visual inspection, refurbishment and reinforcement of rusted structures.

Lubrication system: Lubrication oil analysis. Internal inspection, blasting and painting, if necessary of lube oil tank. Function check of oil mist fan. Function check of all oil pumps. Refurbishment or replacement of air fan of oil coolers. Replacement of oil filters.

Liquid fuel system: Visual inspection and function check of fuel oil pump. Visual inspection of oil intermediate tank. Visual inspection and function check of fuel oil stop valve, fuel oil filter, flow divider, by-pass control valve, by-pass servo-valve, draining valve, check valve, pressure measuring transfer valve, pressure switch, limit switch and piping.

Gas detection and fire extinguishing system: Visual inspection of the system and refilling with CO2, if necessary. Replacement of gas detectors.

Generator and excitation equipment: External and internal inspection of generator and exciter. Rotor withdrawal for inspection. Replacement of air coolers fan.

High voltage cubicle, voltage regulators and protection: Visual inspection for general conditions of stator terminals. Replacement with up to date components, including the protection system. The following equipment needs to be updated with modern day equipment:

- Instrumentation and measuring equipment;
- Governing and control system; protection and emergency shutdown equipment; and
- Low voltage equipment.

The auxiliary systems are generally in good conditions, although some minor works are necessary to fulfil the requirements of hazardous areas, for instance, testing of lifting equipment.

The investment expected to re-commissioning the unit #2 with diesel oil is presented in Table 15 below:

Table 15 - Investment requirements to re-commissioning the BBC Type 11-B unit with diesel oil

Application	**Cost [MUSD]**
Gas turbine major overhaul	2.32
Start gear and reduction gear box check	0.06
Electrical system	0.93
Control system	1.16
Field engineering	0.16
Dismantling, erection	0.52
Contingency	0.36
Total	**5.50**

7.1.3 Re-commissioning of unit #3 with diesel oil

The necessary measures to re-commissioning the GE Frame 5 unit are minor as this unit is being put in operation, in case of emergency.

Vattenfall Power Consultants AB draft inception report (Vatenfall, 2009) describes the following necessary measures re-commissioning the unit with diesel oil:

Air intake: Replacement of filter elements.

Compressor: Inspection of inlet guide vane and blades with a boroscope.

Gas turbine package: Inspection of vane and blades with boroscope. Function test all package motors. Calibration of all pressure and temperature gauges. Disassembling for visual inspection of combustion chamber and non-destructive testing. Refurbishment of the combustion chamber, if necessary. Disassembling of fuel injectors for visual inspection. Replacement of fuel injectors, if necessary. Servicing of the turbine black start diesel engine. Open and inspect the accessory gear box. Open and inspect the load gear box. Clean and pressure test lube oil tube bundles. Supply and fit new lube oil filters. Supply and fit new control oil filters. Supply and fit new hydraulic oil filters. Inspect the accessory coupling and supply replacement coupling bolts. Inspect the load coupling and supply replacement coupling bolts.

Completely check and rewire, if necessary, the instrumentation and control devices. All devices shall be calibrated and tested for further use.

Fuel system: Visual inspection and function check of fuel oil stop valve, fuel oil filter, flow divider, by-pass control valve, by-pass servo-valve, starting-failure draining valve, check valve, pressure measuring transfer valve, pressure switch, limit switch and piping, fuel gas valve and piping.

Electrical system: Alternator rotor check. Check stator and rotor wedges. Calibration of the pressure and temperature instrumentation. Check generator CT's and VT's. The alternator circuit breaker must be overhauled. The low voltage switchboards gears, MCC, to be function checked. Function check of AC and DC including emergency switch over from AC to DC. Check for proper setting and function AVR, medium voltage regulator (MVR), protections and synchronising equipment.

Control system: All signals, control logics, protection and interlocking must be checked and function tested. Check sequences for proper functioning during test run. Check governor for proper functioning during test run. Replace battery in the memory back-up. Check selected turbine protections for proper function during test run.

Auxiliaries: Fire extinguishing system and gas detection system must be checked. Air/ Water Coolers to be overhauled and cleaned. Gas detection system. Visual inspection according to local regulations. Visual inspection of fire extinguishing system.

The investment expected to re-commission unit #3 is presented Table 16 in the below:

Table 16 - Investment requirements to re-commissioning the GE Frame 5 unit with diesel oil

Application	**Cost [MUSD]**
Gas turbine minor overhaul	0.58
Control system	0.35
Contingency	0.36
Total	**1.29**

7.2 Plant Conversion to Natural Gas

The necessary measures to convert the plant to gas firing include replacing the current fuel nozzles currently designed for liquid fuel. The gas conversion shall also include the necessary works to re-commissioning the plant, as described in the section 7.1 above. Additional gas conversion measures are therefore related to gas supply to Maputo power plant including the gas fuel skid and plant piping hardware.

Due to current plant technical status, the gas conversion analysis focuses the unit #2 and #3 only.

7.2.1 Conversion to natural gas for unit #2

This unit was designed and installed to run with diesel oil only. The necessary measures required to convert the BBC Type 11-B to run with natural gas are additional to those described in the section 7.1.2.

The additional measures to convert the unit into naturals gas fired turbine, as recommended by Vattenfall Power Consultants AB draft inception report [5] are summarized as follows:

- Replacement of the oil fuel burner to a gas burner type;
- Installation of new fuel metering and gas control skid;
- Modification of the current fire extinguishing system, including for gas detection and gas alarms;
- Modification and upgrade of the control system.

The expected investment to convert the unit #2 and re-commissioning with natural gas is presented in Table 17 below:

Table 17 - Investment requirements to convert the unit #2 to natural gas

Application	**Cost [MUSD]**
Gas turbine major overhaul	2.32
Electrical system	0.93
Start gear and reduction gear box check	0.06
Control system	1.16
Field engineering	0.17
Gas turbine LEV combustor	0.93
Gas fuel control and metering skid	0.35
Dismantling and erection	0.52
Contingency	0.36
Total	**6.80**

7.2.2 Conversion to natural gas for unit #3

As per for the BBC Type 11-B unit gas conversion analysis, the necessary measures required to convert the GE Frame 5 to run on natural gas are additional to those described in the section 7.1.3.

These measures, as recommended by Vattenfall Power Consultants AB draft inception report (Vatenfall, 2009) are summarized as follows:

- Unit extensive major overhaul to suit the gas conversion option;
- Replacement of control system and control panels;
- Replacement of electrical cubicles; and
- Replacement of generator control / protection panel, MCC, battery charger and battery pack.

The expected investment to convert the unit #3 and re-commissioning with natural gas is presented in Table 18 below:

Table 18 - Investment requirements to convert the unit #3 to natural gas

Application	**Cost [MUSD]**
Gas turbine major overhaul	1.51
Gas turbine conversion	1.74
Gas fuel control and metering skid	0.00
Electrical system	1.16
Control system	0.17
Field engineering	0.00
Contingency	0.93
Total	**5.87**

7.3 Plant Re-commissioning with Combined Gas and Steam Cycles

The Maputo power plant was built to operate on open cycle only. In order to harness the full potential from the converted natural gas turbine a simple combined cycle gas and steam turbine is proposed.

Due to current plant technical status, the gas conversion analysis focused the unit #2 and #3 and the combined gas and steam turbine cycle focus these two units only. As stated in the Chapter 6, a common HRSG is not considered in this project work, as the two units are installed 140 metres from each other.

7.3.1 Combined Cycle for unit #2 and unit #3

The necessary measures required to retrofit the unit #2 to a combined cycle are additional to those described in the section 7.2 and requires extensive effort to install new equipment. The summary of additional equipment requirements are below:

- Installation of a boiler and a steam turbine to suit the proposed combined cycle for each unit;
- Installation of a water cooled condenser, for each unit. The assumption is to use sea water as the plant is situated adjacent to the sea;
- Installation of a common water treatment plant;
- Upgrade of the control system of each unit;
- Installation of bypass stack system, for each unit, to avoid the units be operated in open cycle, to secure appropriate cooling of HRSG.

The expected investment to re-commissioning the units #2 and #3 with combined natural gas and steam cycle is presented in Table 19 and Table 20, respectively.

Table 19 - Investment requirements to retrofit the unit #2 to a combined cycle

Application	**Cost [MUSD]**
Gas turbine major overhaul	2.32
Start gear and reduction gear box check	0.058
Electrical system	0.928
Control system	1.16
Field engineering	0.156
Gas turbine LEV combustor	0.928
Gas fuel control and metering skid	0.348
HRSG	10.44
ST/Gen	14.268
Condenser	1.276
Balance of plant	3.132
Contingency	3.6
Total	**38.61**

Table 20 - Investment requirements to retrofit the unit #3 to a combined cycle

Application	**Cost [MUSD]**
Gas turbine major overhaul	1.74
Gas turbine conversion	0.928
Gas fuel control and metering skid	1.16
Electrical system	0.156
Control system	1.16
Field engineering	0.348
HRSG	7.888
ST/Gen	11.02
Condenser	1.044
Balance of plant	3.248
Contingency	3.6
Total	**32.29**

7.4 Technical and Emissions Analysis

The overall plant assessment as per calculation from previous chapters gave the following summarised results, see Table 21 and Table 22 below.

The detailed calculation sheets are presented in Appendix V.

Table 21 - Technical and emissions analysis results for unit #2

Parameter	**Unit**	**GT – Diesel**	**GT – Natural Gas**	**STIG**	**CCGT**
Fuel LHV	[kJ/kg]	42.33	47.59	47.59	47.59
Power Output	[MW]	29.00	29.00	29.00	47.00
Efficiency	[%]	22.63	22.71	22.70	36.74
Fuel consumption	[m^3/h]	9.11	12 014	12 014	12 014
Steam consumption	[kg/s]	N/A	N/A	0.41	20.79
Water consumption	[kg/s]	N/A	N/A	N/A	1 104
Stack temperature	[°C]	445	445	438	153
CO_2 Emissions	[kg/MWh]	1 184	748	748	463
CO_2 Emissions per annum	[tonnes]	221 942	140 306	140 515	140 306

Table 22 - Technical and emissions analysis results for unit #3

Parameter	**Unit**	**GT – Diesel**	**GT – Natural Gas**	**STIG**	**CCGT**
Fuel LHV	[kJ/kg]	42.33	47.59	47.59	47.59
Power Output	[MW]	25.00	25.00	25.00	38.00
Efficiency	[%]	27.79	28.09	28.06	42.27
Fuel consumption	[m^3/h]	5.64	8 397	8 397	8 397
Steam consumption	[kg/s]	N/A	N/A	0.08	13.40
Water consumption	[kg/s]	N/A	N/A	N/A	707
Stack temperature	[°C]	483	483	481	158
CO_2 Emissions	[kg/MWh]	848	605	605	402
CO_2 Emissions per annum	[tonnes]	137 535	98 068	98 169	98 068

7.5 Financial Assessment

Financial assessment for the proposed plant modification is shown in Table 23 below and detailed calculation sheets are presented in Appendix V.

Table 23 - Plant Financial Assessment

Parameter	Unit	GT – Diesel	GT – Natural Gas	STIG	CCGT
Fuel cost	-	0.62 US$/l	7.00 US$/GJ	7.00 US$/GJ	7.00 US$/GJ
Electricity sales	[US$/kWh]	0.116	0.116	0.116	0.116
Operating hours per year	[h]	6 500	6 500	6 500	6 500
Energy output per year	[MWh]	349 670	349 670	N/A	547 352
Financial interest rate	[%]	11.45	11.45	11.45	11.45
Initial Investment	[M US$]	6.79	12.67	-	70.91
Payback time	[Year]	∞	3	-	2
NPV	[M US$]	-318.00	10.32	-	108.84

8 Discussions and Recommendations

8.1 Discussions

The plant performance analysis and re-commissioning on current fuel, diesel oil, gave following results:

- Calculations results similar to current plant performance, based on operational readings;
- The analysis reported:
    - Low initial investment, the major investment to re-commissioning on diesel oil are costs associated with the units' major overall and beneficiation of upgrade to some systems and auxiliaries;
    - The plant gives very low efficiency;
    - The plant operability assessment gave high operating costs due to cost of diesel, leading to negative NPV; and
    - Large environmental footprint with high CO_2 emissions.

For the conversion of the plant to burn natural gas, the assessment found out the following:

- Turbine inlet temperatures limits the plant efficiency, i.e. equipment material limits harnessing the full gas energy;
- Additional analysis gave:
    - Additional costs on initial investment due to installation of some new equipment;
    - High efficiency compared to diesel oil circuit;
    - Positive NPV and low payback time;
    - Low CO_2 emission.

Plant assessment with steam injection gas turbine provided the following:

- The injected steam temperature drives the cycle efficiency;
- Additional analysis gave:
    - Increased power output and improved plant efficiency;
    - The amount of steam that can be injected limited to 0.41 kg/s for unit #2 and 0.08 kg/s for unit #3;
    - To apply STIG cycle the gas turbine need to be uprated; and
    - Since the project does not include updating the installed equipment, STIG cycle does not seem applicable to the current installation.

The combined cycle assessment gave the following results:

- High steam pressure does not necessarily mean high efficiency;
- The optimum steam cycle pressure is around 20bar for unit #2 and 30 bar for unit #3;
- Additional analysis gave:
    - High initial investment, due to installation of new steam cycle;
    - Higher efficiency compared to other cycles;

- High NPV an low payback time; and
- Low CO2 emission.

8.2 Conclusions and Recommendations

The study assessed plant re-commissioning on diesel oil, conversion to natural gas, STIG and CCGT.

The study recommends converting the Maputo Power Plant to natural gas and modifying the gas turbine cycle into combined cycle gas turbine, given that:

- Financial assessment provides very attractive NPV;
- The overall cycle has high efficiency;
- It has low CO_2 emission ;
- For optimum economic and financial results, the plant investment can be delayed, i.e. the steam cycle can be installed after plant conversion;
- In addition, because each unit will have independent HRSG and bottoming cycle the investment can even be better delayed.

To implement the study recommendation the following measures need to be taken into account:

- Conduct detailed combined cycle analysis to determine the optimum plant efficiency;
- Assess the use of one common HRSG and bottoming cycle for both units reduces capital expenditure for the steam side;
- In order to harness the full capacity of unit #2, trade-off analysis for installing a new transformer is recommended;
- Natural gas supply at CTM needs to be assessed in details;
- Full combustion analysis needs to be conducted;
- Assess the current plant interfaces with proposed new equipment, including natural gas piping hardware; and
- Evaluate plant footprint analysis.

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