PROJECT

SESEM – CFT

Contract No. NNE5-2002-96

Guide to Clean Fossil Fuel Technologies for the Power Sector in Latin America and the Caribbean

November 2006

Version: Guide CFT Technologies LAC 1.11.06 .doc

This report has been deducted from the study *A Review of the Power Sector in Latin America and the Caribbean, Evolution in the Market and Investment Opportunities for CFTs* and has been prepared by:

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1 Introduction

A consortium comprising of Centro de Investigaciones Energéticas, Medioambientales y Tecnológicas (Co-ordinator), Forschungszentrum Jülich GmbH / Projektträger Jülich, VGB PowerTech e.V., European Power Plant Suppliers' Association, Gray Associates and Deutsche Montan Technologie GmbH, has been awarded with a contract from the European Commission towards the implementation of the project “Securing Energy Supply and Enlarging Markets through Cleaner Fossil Technology”, hereinafter referred to as ”SESEM”. In the framework of the EU- LAC political dialogues and cooperation agreements the SESEM project is designed to highlight and promote the opportunities in the LAC energy market for priority investments for cleaner fossil fuel technology (CFT).

The guide is aimed at decision makers from politics and power industry in Latin America and the Caribbean (LAC) in order to make them familiar with the clean fossil fuel technology options for the LAC energy market – be it greenfield plants or refurbishment of existing plants.

A review of the LAC power market has been performed in **Chapter 2** describing fossil fuel power plant technologies presently used in LAC (based on a database prepared by OLADE).

LAC decision makers shall be informed through **Chapter 3** about commercially available state-of-the-art CFT technologies from the EU which may find application in their power market in order to generate power with high efficiency and availability as well as lowest emissions.

Chapter 4 compares the electricity generation costs of different types of power plants and different sizes.

2 Fossil fuelled power plants in LAC (Technologies and Statistics)

Chapter Key Topics:

- The main types of power plants technologies applied are gas fired turbines and gas or oil fired boilers with steam turbines; however, power generation by combined cycle gas turbine technology will obtain more and more shares in the region.
- In order to meet the growth of power demand annually roughly 12 GW of new power plants have to be installed.
- The evaluation of the power plant technologies in LAC has been derived from the Energy-Economic Information System (SIEE) operated by OLADE.
- From the number of plants in the LAC 73% of the power plants have nominal outputs less than 50 MW, 23% are in the range of 50 to 400 MW and 4% are in the range of between 400 to 1000 MW.
- In the LAC region the main types of power plants are diesel engines (mainly for decentralised power production in remote areas) and power plants with conventional steam or gas turbines.
- From the installed capacity in thermal power generation, gas turbines account for 27%, steam turbines for 56%, gas combined cycle plants contribute 7% and diesel engines 6% of the power generation. The balance of 4% is made up by geothermal and nuclear power plants.
- 85% of the power generation is based on oil and natural gas. Coal actually plays no major role in the LAC power sector although large reserves are present in the region.
- In the LAC region the main types of power plants are diesel engines (mainly for decentralised power production in remote areas) and power plants with conventional steam or gas turbines.
- A replacement potential of actually around 9 GW can be identified for the running decade.

The following evaluation of the power plant technologies in LAC has been derived from the Energy-Economic Information System (SIEE) operated by OLADE. Organisations in the LAC countries are appointed to keep the database updated by providing regular information to OLADE.

However, the database on thermal power plants and their technologies shows minor gaps of data. This can be recognised by comparing the total installed capacity of 121 GW (without hydropower) in the region to the corresponding calculated installed capacity of 104 GW based on the power plant database. Nonetheless, an error of 14% (i.e. 17 GW difference) seems to be tolerable and does not adversely affect the representativity of the evaluation.

Finally, the evaluation shall give a picture of the situation in the power sector and thus may help in understanding its necessities.

2.1.1 Database on LAC power plants (part of SIEE)

In the power plant database 1,295 power plants are recorded according to the following data:

- **Country**
- **Name of plant**
- **Location of power plant**
- **Operating company**
- Owner of plant
- **Year of commissioning**
- Reference year of data update
- **Status of activity**
  - decommissioned
  - operating
  - under construction
- **Type of Plant**
  - Combined Cycle Gas Turbine
  - Diesel engine
  - Fluidised Bed
  - Gas turbine
  - Geothermal
  - Nuclear
  - Steam turbine
- **Nominal Power [MW]**
- Effective Power [MW]
- Power generation per year [GWh]
- Load factor of plant [%]
- US$/kW Investment
- **Type of fuel for power generation**
  - Biomass (biogas, bagasse)
  - Black liquor
  - Coal
  - Diesel
  - Fuel oil
  - Gas (e.g. from blast furnace)

- Natural Gas
- Steam (from geothermal sources)
- Uranium

➢ Thermal efficiency of plant [%]

Most entries have been found in the data categories given in bold letters. Especially data taken from the categories country, year of commissioning, type of plant, nominal power and type of fuel have served for the evaluation in the following chapters.

2.1.2 Survey of the size of power plants

The number of power plants in the countries varies significantly (see figure below). Brazil has registered 738 power plants in the database which accounts roughly for 60% of the total registered plants. However, 90% of those plants are below 50 MW power output.

Regarding the installed capacities of the power plants in the region it can be recognised that 73% of the plants have nominal power outputs <50 MW. In the range of 100 to <400 MW 23% of the plants can be found and 4% of the plants have power outputs in the range between 400 and <1000 MW. There are 9 power plants with power outputs between 1 and 2 GW and only 4 power plants show a nominal power output of more than 2 GW. Two plants of those operate in Mexico (type: both steam turbine fired with fuel oil) and the other two in Venezuela (type: one steam turbine and one gas turbine, both fired with natural gas).

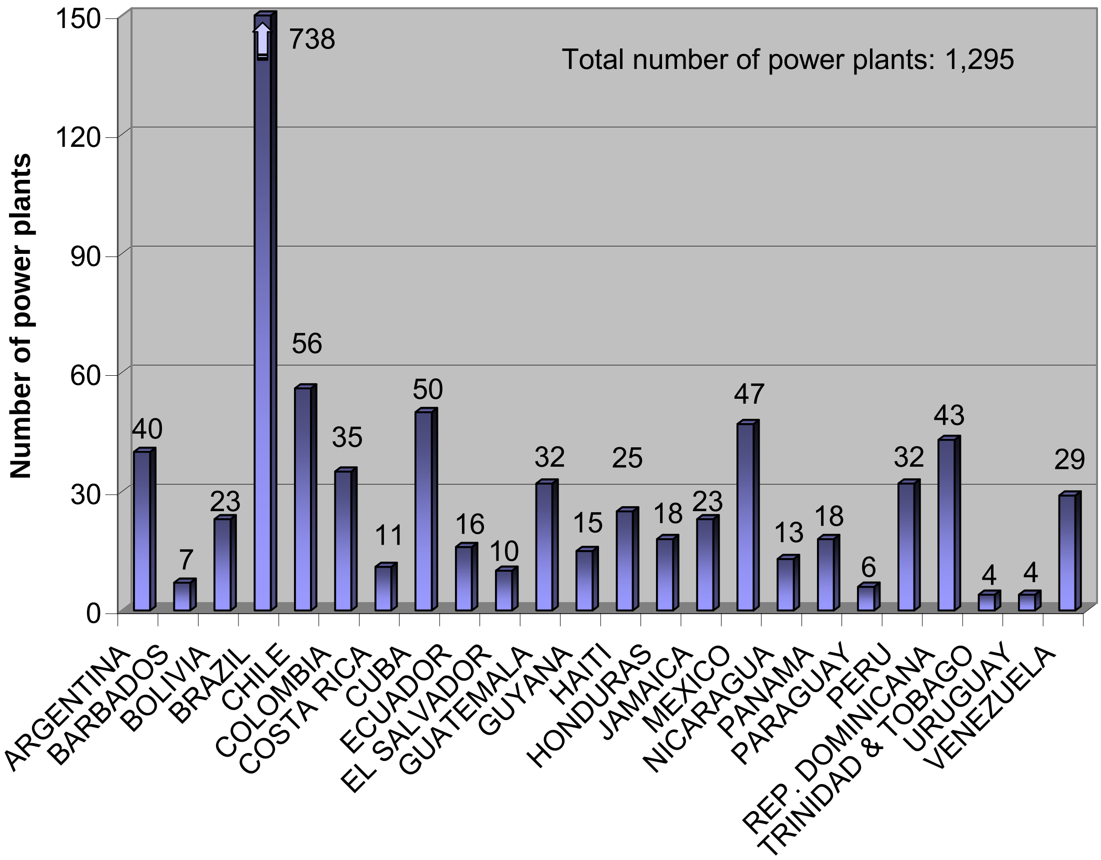


Figure: Number of power plants per LAC country registered in the power plant database, 2004 (source: OLADE)

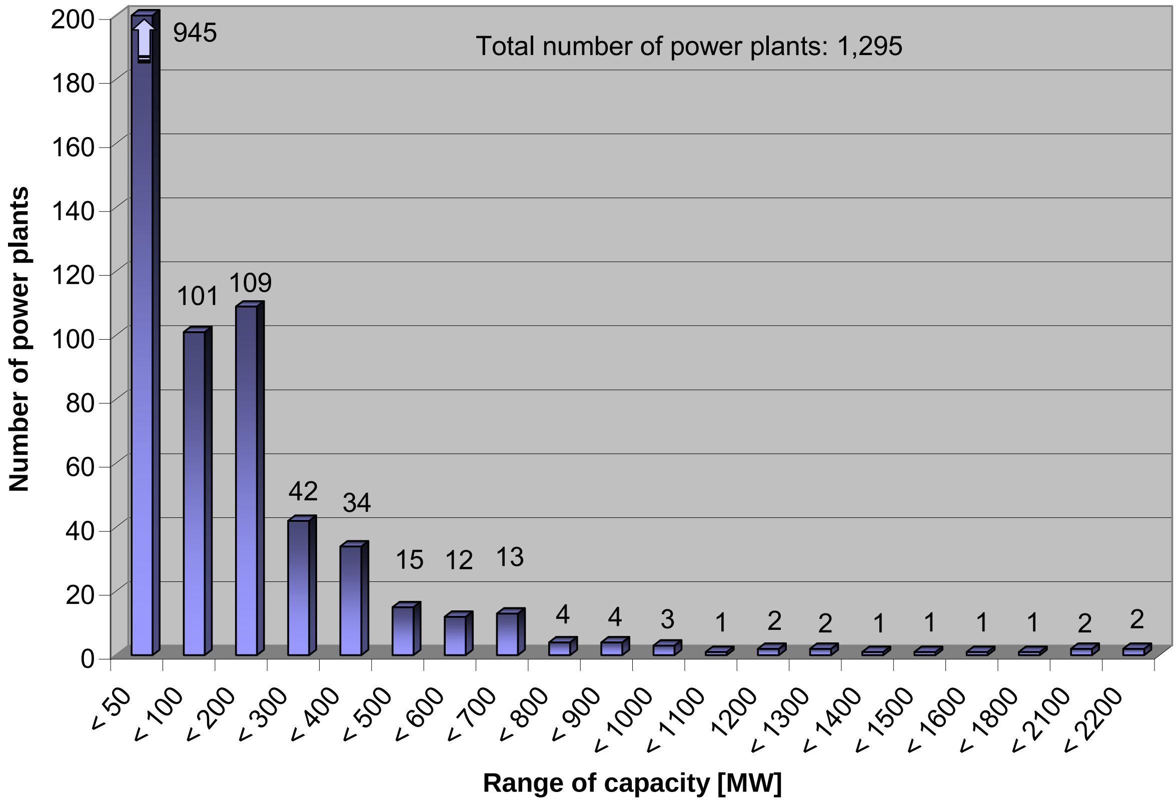


Figure: Capacity range of power plants in LAC acc. to power plant database, 2004 (source: OLADE)

2.1.3 Types of power plants in operation

In the LAC region the main types of power plants are diesel engines (mainly for decentralised power production in remote areas) and power plants with conventional steam and gas turbines (see figure below). Since the 1980s natural gas combined cycle plants and - using renewable energies - also geothermal power plants have been constructed and commissioned. In addition to the gap of information about 17 GW of installed power (see para 2, p.6) there is unfortunately no information available about the types of the 738 Brazilian power plants which account for ca. 25 GW power capacity in total.

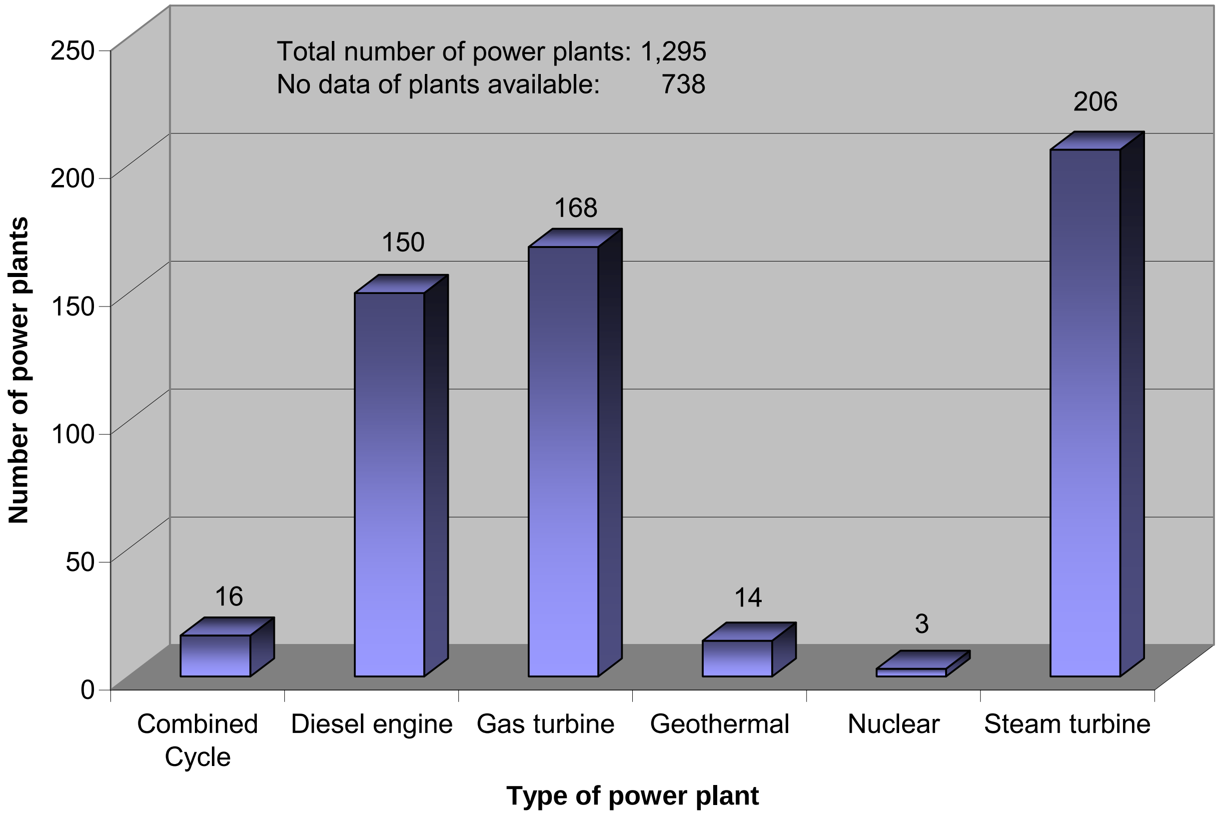


Figure: Number of different power plant types in LAC acc. to power plant database, 2004 (source: OLADE)

Considering, however, the amount of installed power capacities it becomes obvious that the diesel engines, although as numerous as the gas turbine power plants, provide only 6% of the overall power production (see figure below). Gas turbines account for 27% and steam turbines for 56% of the power generation. Gas combined cycle plants contribute 7% to the power generation. The balance of 4% is made up by geothermal and nuclear power plants.

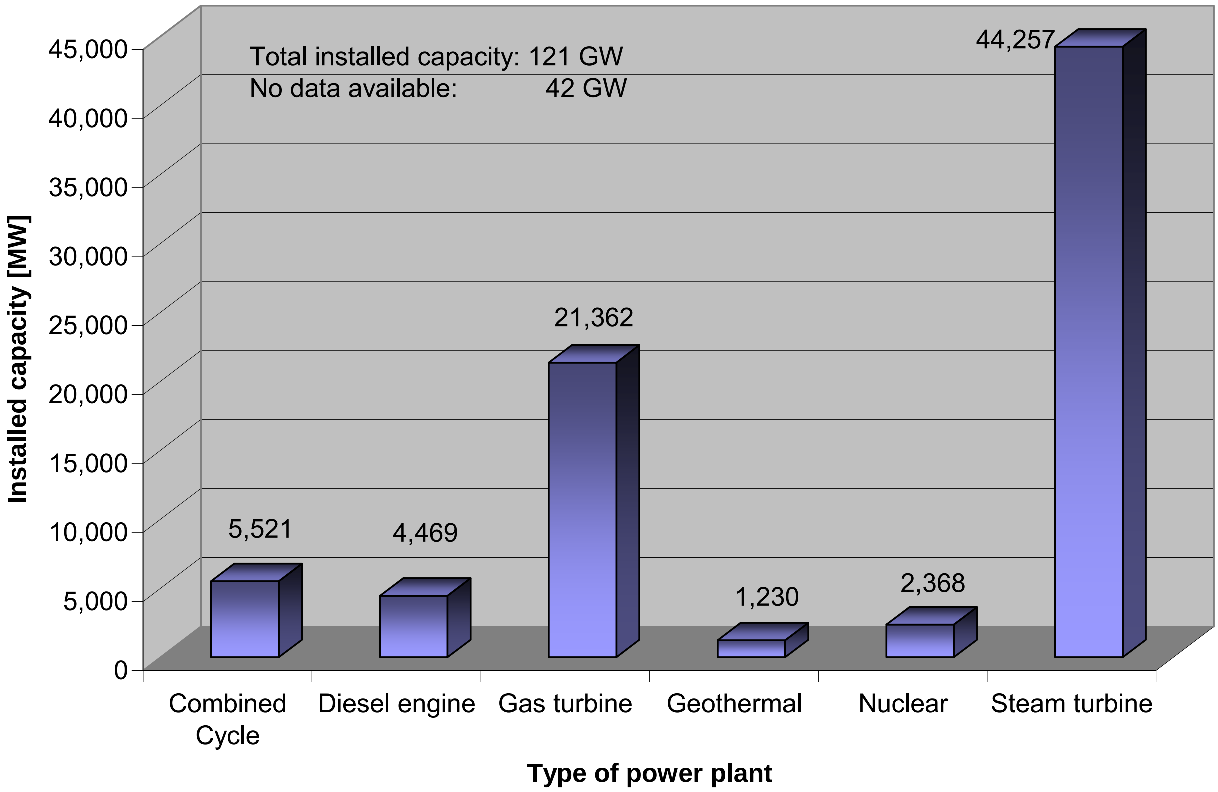


Figure: Installed capacity of different power plant types in LAC acc. to power plant database, 2004 (source: OLADE)

2.1.4 Fuels for power generation

The variety of fuels used in the power plants comprises biomass (biogas, bagasse), black liquor, coal, diesel, fuel oil, gas (e.g. from blast furnace), natural gas as well as steam (from geothermal sources) and Uranium. Regarding the number of power plants it becomes evident (see figure overleaf) that most plants operate on (in descending order) diesel, biomass, natural gas and fuel oil.

As most diesel engines and biomass plants represent power plants of lower capacity, the power generation by fuel has to be highlighted in order to get a feeling for the importance of a certain type of fuel. The figure overleaf shows that natural gas (50%) contributes most to the power generation, followed by fuel oil (25%), diesel (10%) and coal (7%). Biomass has only a share of 3% (similar to the nuclear power generation), despite the high number of plants in operation (mainly from Brazil).

It is not surprising that about 85% of the power generation is based on oil and natural gas while the region is rich of oil and gas reserves. The fossil fuel coal actually plays no major role in the LAC power sector although large reserves are present in the region. Coal is dedicated mostly for exports to Europe and the United States. Nevertheless, some coal fired power plants (pulverised fuel, conventional steam cycle) can be found in Colombia, Chile, Brazil, Dominican Republic and Mexico.

Co-combustion of coal and biomass actually is of minor importance as there are only a few coal fired power plants available in the region. Co-combustion may gain importance when the number of coal fired plants will increase in the medium to long term future.

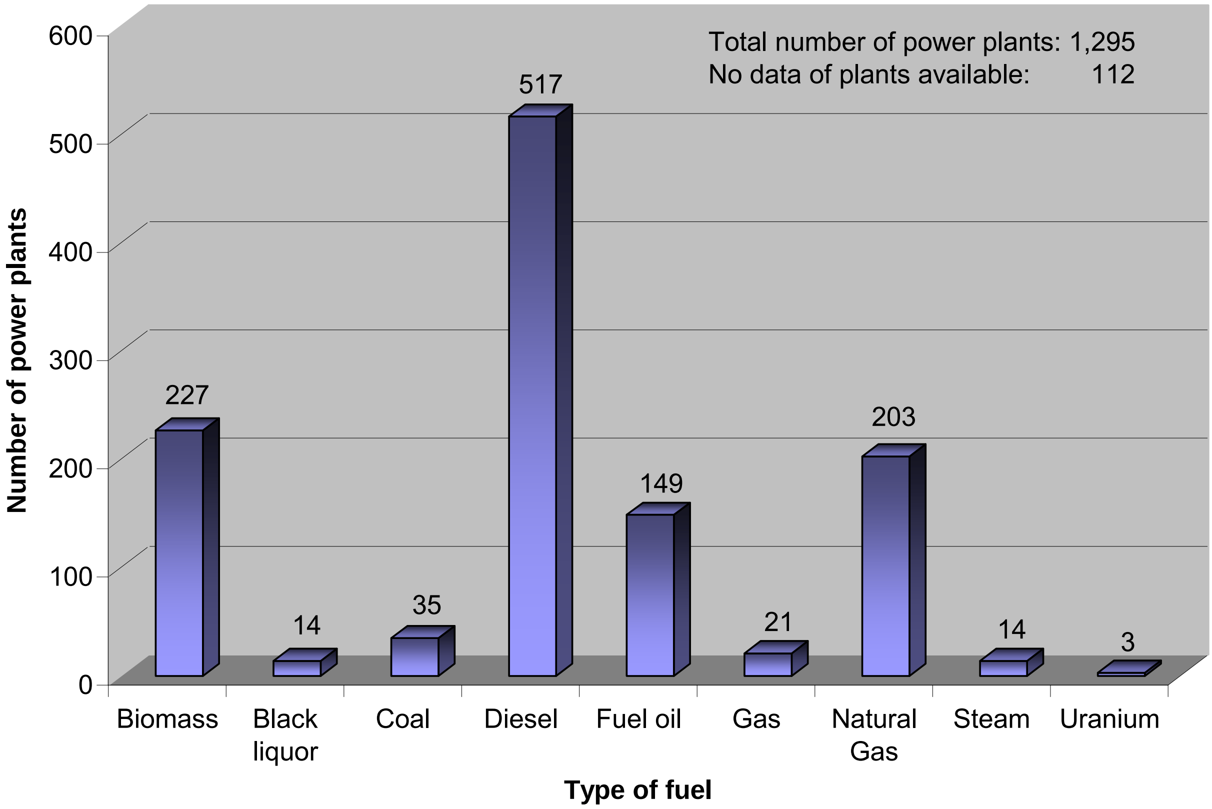


Figure: Fuels used in LAC power plants acc. to power plant database, 2004 (source: OLADE)

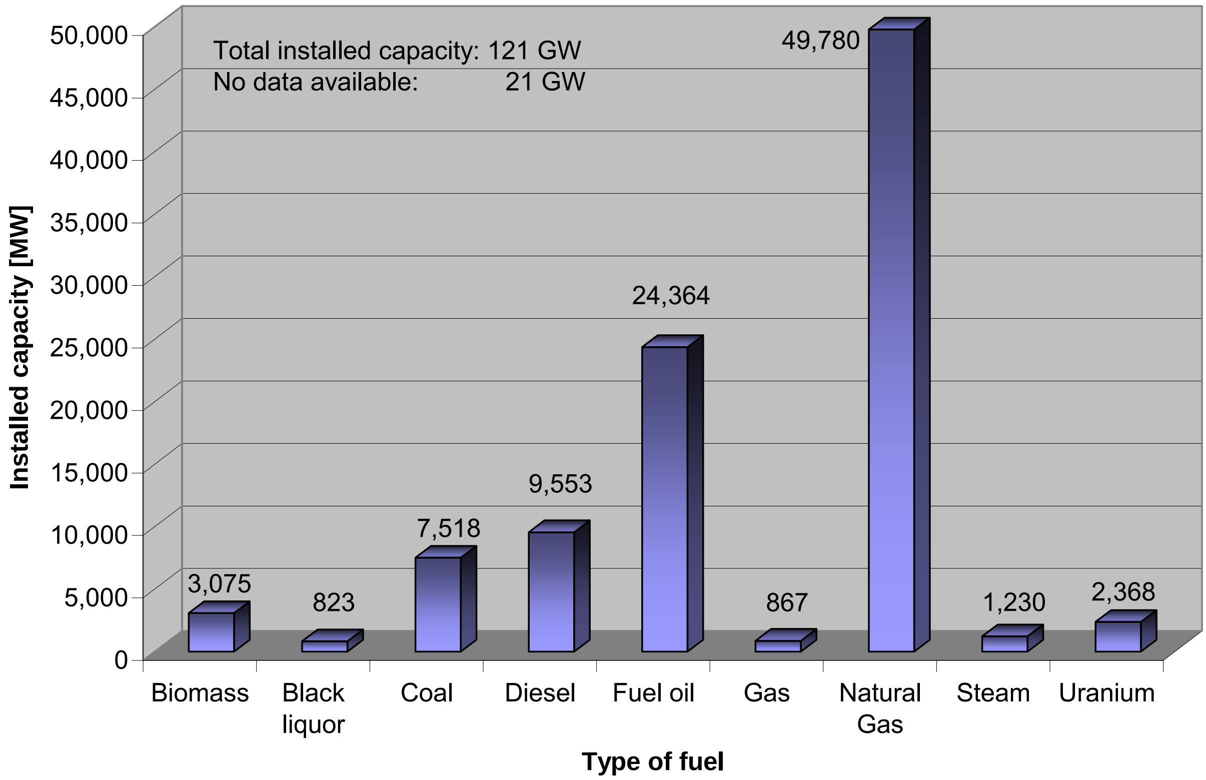


Figure: Contribution of different fuels to power production in LAC acc. to power plant database, 2004 (source: OLADE)

In the following figure (below) the installed capacities of the different types of power plants are compared, however, this time under consideration of the fuel used. Combined cycle plants are using mostly natural gas; only a minor number of plants uses also fuel oil. Diesel engines run on both diesel and fuel oil. As a speciality, there is one diesel engine also operating with biogas in El Salvador. The gas turbine power plants use natural gas at a high share, but also some facilities are running on fuel oil and diesel. The power plants operating with steam turbines mainly burn natural gas and fuel oil. To a minor extent coal is used at feedstock. There are even some steam turbine plants operating on diesel.

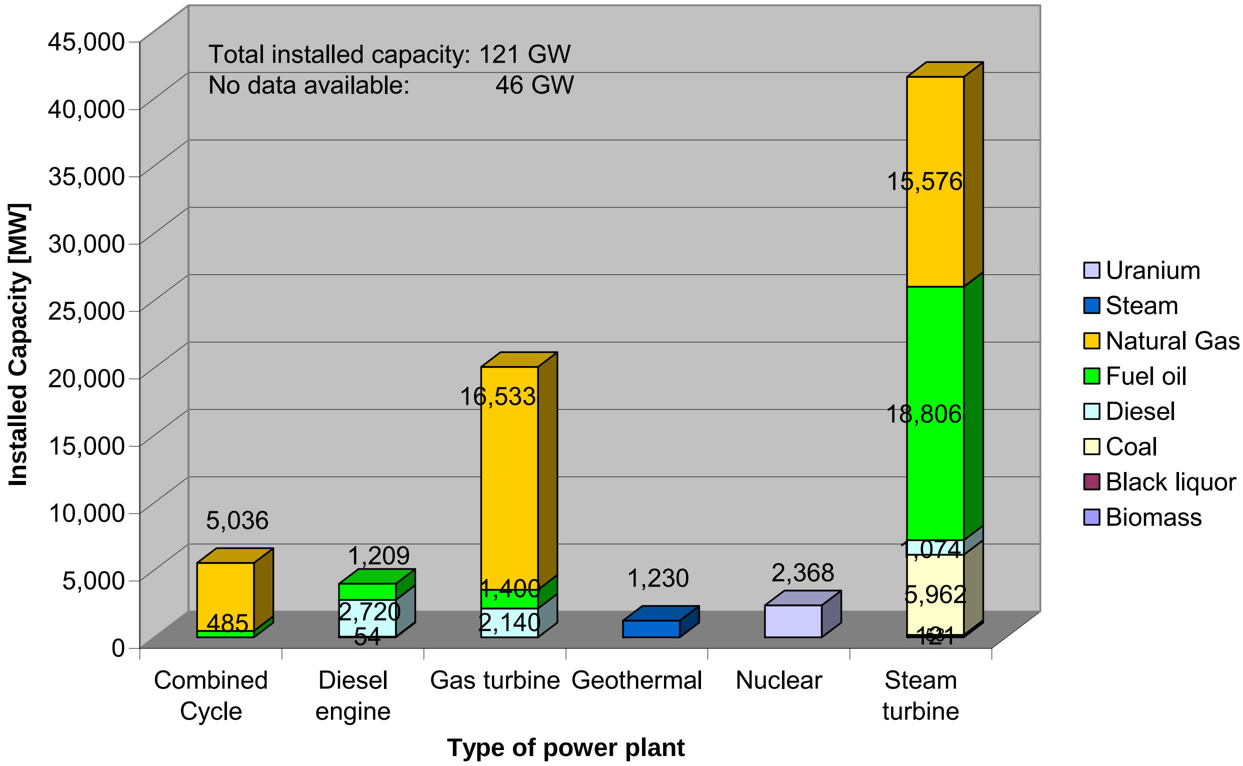


Figure: Fuel feed to different types of power plants acc. to power plant database, 2004 (source: OLADE)

2.1.5 Age of the power plants

The figure overleaf shows the decade of power plant commissioning and summarises the installed capacities per decade.

The main development of the power market commenced in the 1960s and increased through the 1970s. However, a remarkably decrease of new capacities can be detected in the 1980s. In the 1990s again considerable capacities have been installed contributing to the overall increase of generating capacities in LAC. In the decade < 2010 obviously only 4 years have passed and 6 years are to come where the power plant capacities will further increase.

In the period until the end of the 1960s mainly steam turbine power plants have been constructed (see figure overleaf). Since the 1970s gas turbines became a main competitor to steam turbines for large scale power generation. Also since the 1970s an increasing number of diesel engines can be recognised in the LAC power market taking care of decentralised power supply in remote areas.

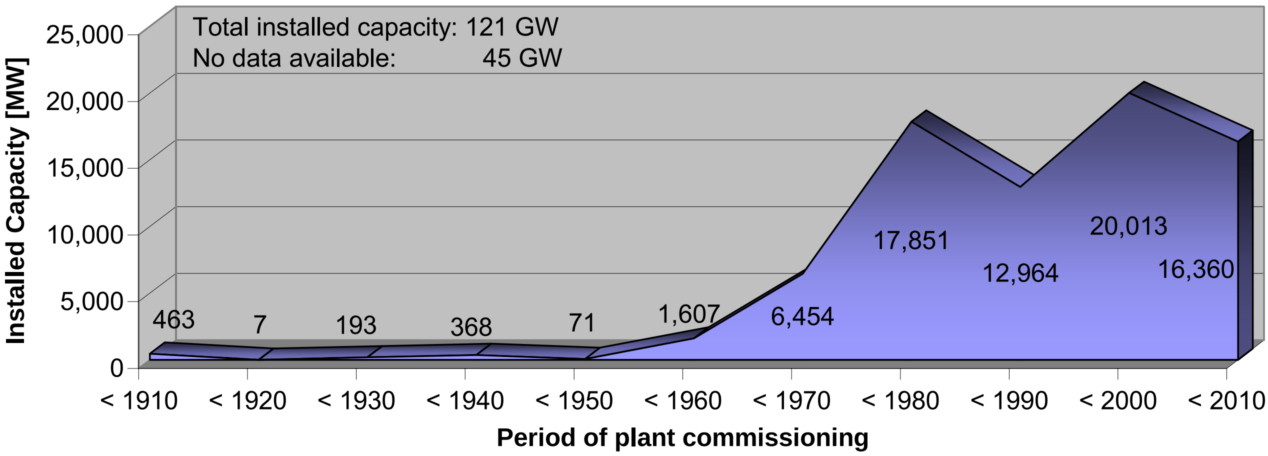


Figure: Installed capacity and period of plant commissioning acc. to power plant database, 2004 (source: OLADE)

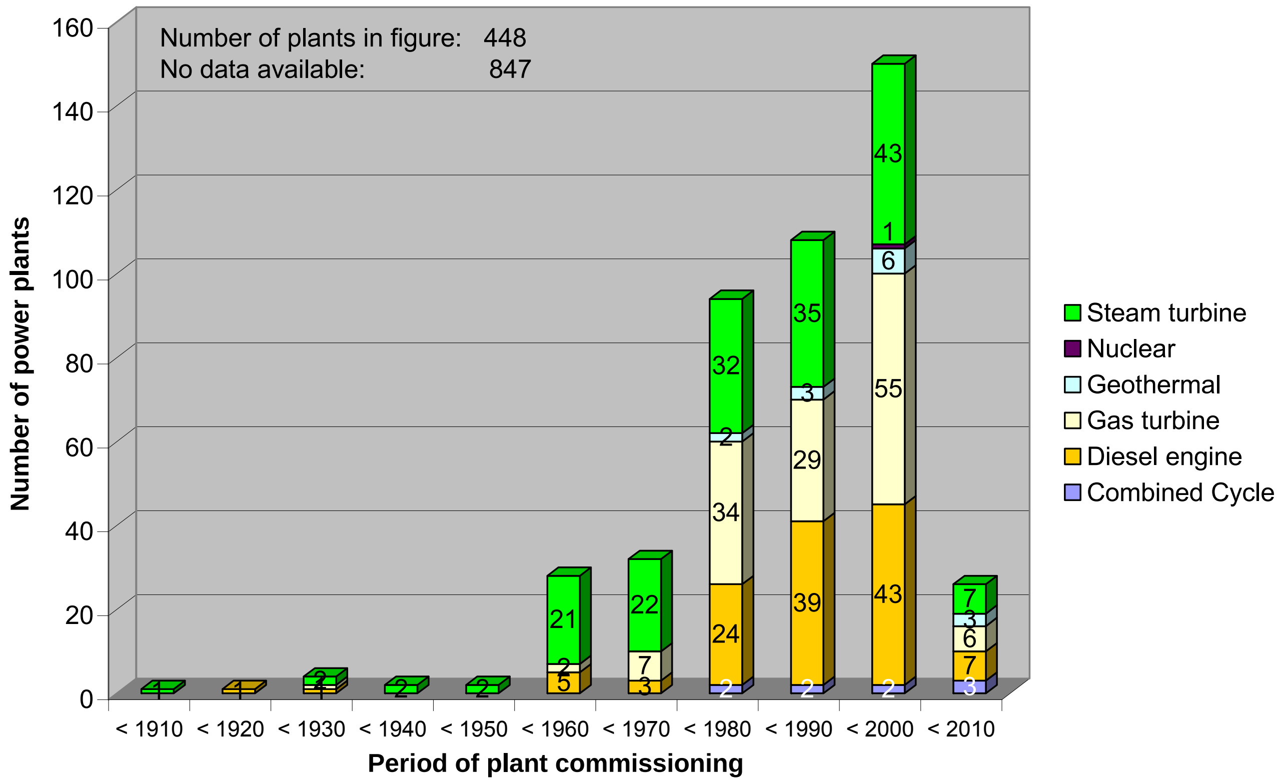


Figure: Periods of commissioning of different power plants acc. to power plant database, 2004 (source: OLADE)

Taking a possible replacement of the installed capacities after 30 years of operation into account a potential can be calculated which is actually in the order of 9 GW (7%) of the actually installed capacities, but will rise in the coming decade. Moreover, the LAC power market is growing at a rate of 4-5 % p.a. (i.e. some 12 GW p.a.).

2.1.6 Emission reduction from power plants

Actually there is no legislation in place that regulates emission output of power plants of any size. Hence, most commonly there are no emission reduction facilities installed at the operating power plants in LAC.

3 EU CFT technologies – options for the LAC power market

Chapter Key Topics:

- Adequate EU CFT technologies for large scale power generation corresponding to the LAC power market needs comprise gas and steam turbine plants as well as combined-cycle plants running on natural gas.
- Options for the longer term (>20 years) include pulverised coal combustion and IGCC plants – for the time when the oil and gas reserves of the region start to deplete.
- Solid Fuel Processing has emerged as an important clean coal technology. Blending of different coal types or of coal with biomass or waste, washing, cleaning or grinding became standard procedure for pollution minimisation and for improvement of efficiency.
- Co-combustion of coal with biomass or waste fuels offers many advantages over using the fuels solely. Using coal as part of a fuel mix allows operators to be able to compensate for variations in the fuel mix and stabilise combustion. From a coal perspective, the use of biomass or wastes offers the potential to use cheaper fuels. There are also potential global and local environmental benefits if coal is partially replaced with biomass fuels that do not release fossil-derived CO_2 or other pollutants such as SO_2.
- Existing power plants can be modernised through refurbishment or upgrading (retrofit, repowering and rehabilitation) instead of building new plants. Especially the retrofitting of ageing power plants with pollution control equipment or repowering with fluidised bed boilers or gas turbines will be cost-effective compared to the construction of new power plants.
- Flue gas treatment can achieve virtually any level of emission reduction. However, retrofitting has often considerable practical and economic implications. Installing FGD and NOx control will usually add 25% to the cost of a new PF plant and for retrofitting of an existing plant it may add up to 30% of the entire capital costs.
- EU technologies offer retrofit options for emission reduction either by modifications of the burner design (low-NOx), the process design (air staging, reburning), plant control systems or by end-of-pipe pollution abatement and control technologies (e.g. filters, scrubbers, etc.).

According to the findings about the LAC power market (see chapter 2) natural gas and oil are the main fuels used for fossil fuel power generation. Coal actually plays only a minor role.

Corresponding to the recent requirements of the LAC power sector this chapter will focus on available state-of-the-art EU technologies for large scale power generation from oil and gas, i.e.:

- Gas Turbine Power Plant
- Combined Cycle Gas Turbine (CCGT) Power Plant
- Steam Turbine Power Plant

Nevertheless, as projections of the future oil and gas demand indicate a depletion of the resources in the region at less than 30 years coal may gain an increasingly importance in the LAC power sector. Therefore also two options of power generation from coal will be taken into consideration, i.e.:

- Pulverised Fuel Combustion
- Integrated Gasification and Combustion of Coal (IGCC)

3.1 Gas / oil fired gas turbine power plants

3.1.1 Gas turbines characteristics

Gas turbines can be divided into three main types:

- Heavy-duty industrial gas turbines (GTs) which are considered conventional in design, the firing temperatures and cycle efficiency of these units are conservative by modern standards and this is reflected in the design and choice of materials throughout the GT. These units range in output from 15 to 170 MW and yield an open cycle efficiency of approximately 29 to 34 per cent. These conventional design units are noted for being very reliable machines and they have accumulated considerable operating hours.
- Heavy-duty industrial GTs which are considered “state of the art”: The firing temperatures, compression ratios, combustion systems, cooling and sealing systems, material selection, manufacturing processes and blading designs in these machines are considered in many cases to be “state of the art”. In general, these units fall into two main output bands in simple cycle 50 Hz configuration: 60 to 70 MW and 250 to 270 MW. The open cycle efficiency figures range from about 34 to 38 per cent.
- Aero-derivative GTs: These GTs as the term suggests are land-based derivatives of successful aero-engine designs. Aero-derivative units are characterised by high open cycle efficiency figures and short start-up times, compared with heavy-duty industrial GTs. The largest aero-derivative GTs are in the region of 45 to 50 MW, going down to 2 to 3 MW at the low end of the range. Typically open cycle efficiencies in the 25 to 50 MW output band are in the range 38 to 42 per cent.

All three types of gas turbines can be used in open-cycle (OCGT) or combined-cycle (CCGT) configuration, which are in more detail described in Annex 1.

3.1.2 Gas fired turbines

The term "gas turbine" is most often used as an abbreviation for a gas-turbine engine, which is a heat engine that accepts and rejects heat and produces work. The input heat is usually in the form of fuel that is burned (giving rise to the term “combustion turbine”), but may also come from another process via a heat exchanger. The rejected heat is usually in the form of hot engine-exhaust flow released to the atmosphere, but may also be rejected to another process via heat exchanger. The work may be given as output torque in a turning shaft or as the velocity and pressure energy in a jet, which would produce thrust on a moving airplane. The term “gas turbine” can also be used more narrowly for just the turbine expander in a gas-turbine engine.

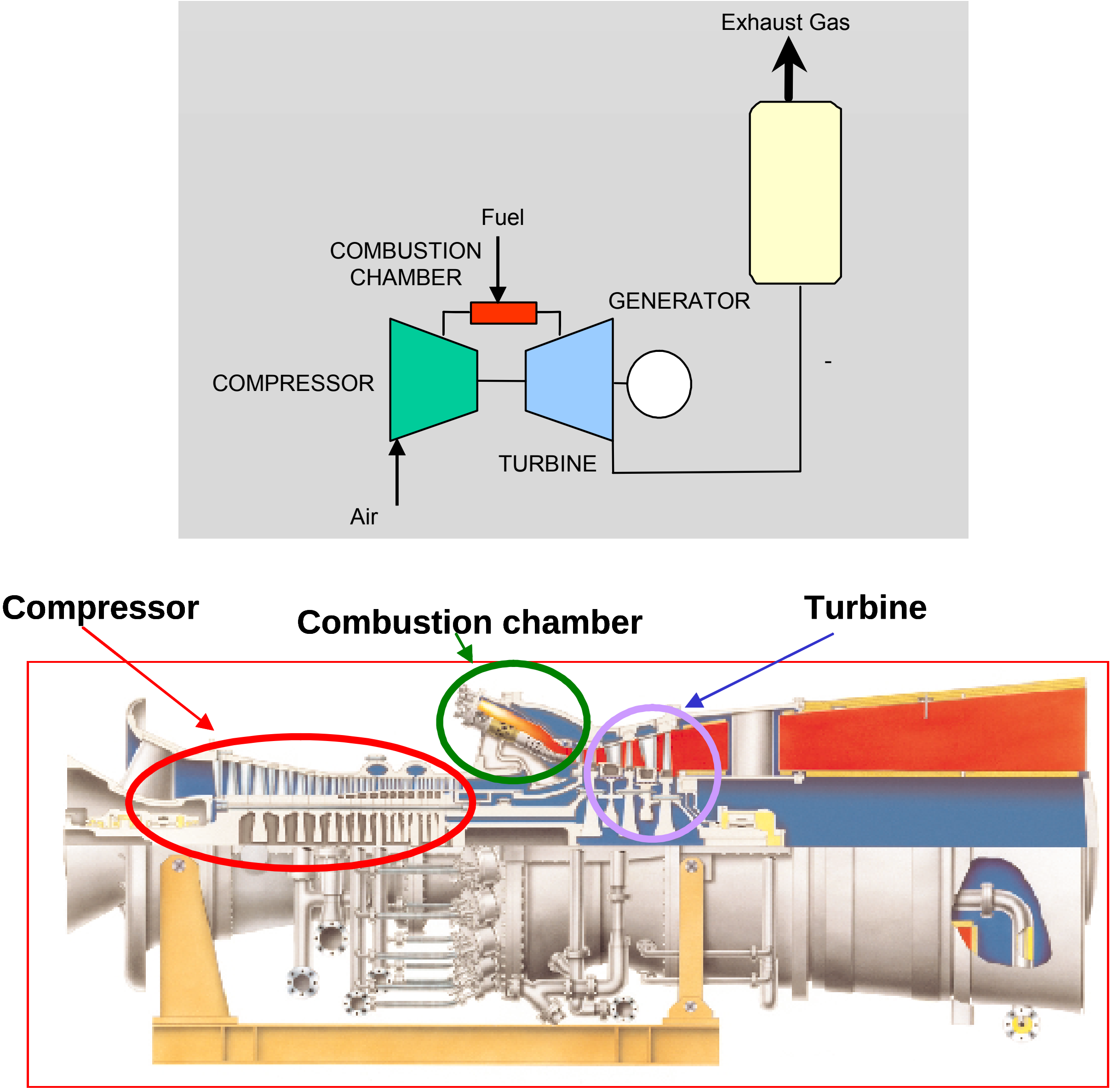


Figure: Simple gas turbine cycle

Therefore, the gas turbine is typically an internal combustion rotary engine, the most widely known example of which is the jet aircraft engine. Basically, the engine burns a lean mixture of fuel with compressed air. The hot pressurized combustion gases expand through a series of rotating turbine wheel and blade assemblies resulting in shaft power output, propulsive thrust, or a combination of the two. Today the gas turbine engine is a widely used source of propulsive thrust and mechanical power.

The basic gas turbine engine consists of a compressor, a combustor, and a turbine in series. The basic cycle is illustrated in the figure given above. The intake air is compressed and delivered to the combustor at substantially increased pressure and temperature. There, the fuel is burned and the temperature raised to a higher value (beyond of 1100 °C during continuous operation). These high pressure/high temperature combustion gases then expand through the turbine, causing it to rotate. The turbine drives the compressor and any excess energy available produces shaft power, thrust, or a combination of both. Every gas turbine engine operates on some variation of this cycle.

The number of stages or configuration can change, but there is always compression followed by heating followed by expansion of the working fluid (air in this case).

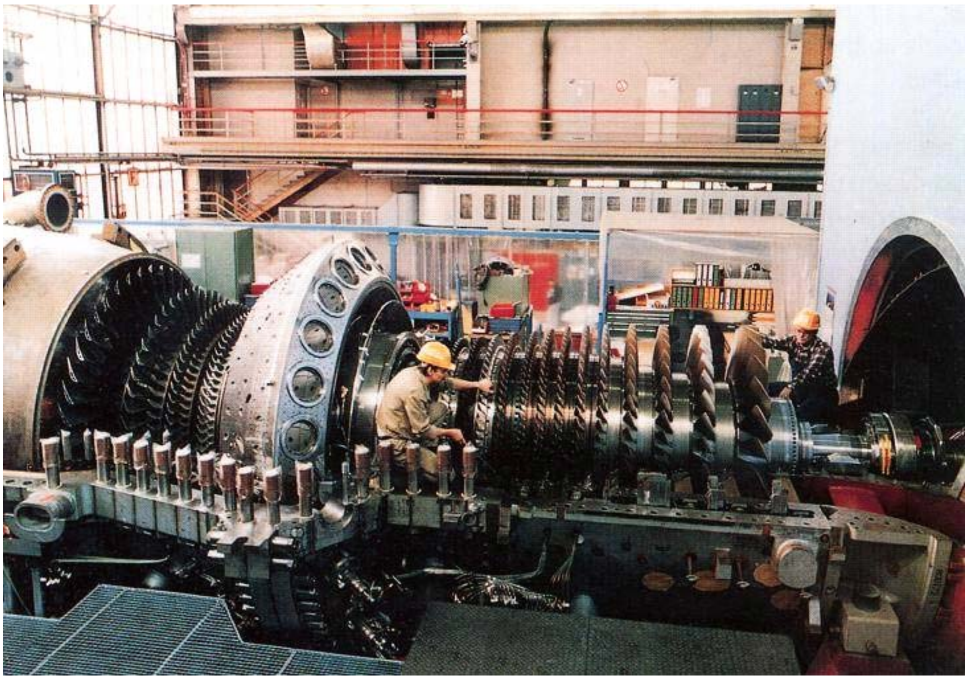


Figure: Gas turbine assembly (photo: courtesy of Alstom)

It is important to realize that in the gas turbine the process of compression, combustion and expansion do not occur in a single component as they do in a reciprocating engine. They occur in components which are separate in the sense that they can be designed, tested and developed individually, and these components can be linked together to form a gas turbine unit in a variety of ways (see figure above). The possible number of components is not limited to the three already mentioned. Other compressors and turbines can be added, with intercoolers between the compressors, and reheat combustion chambers between the turbines. A heat exchanger which uses some of the energy in the turbine exhaust gas to preheat the air entering the combustion chamber may also be introduced. These refinements may be used to increase the power output and efficiency of the plant at the expense of added complexity, weight and cost. The way in which these components are linked together not only affects the maximum overall thermal efficiency, but also the variation of efficiency with power output and of output torque with rotational speed. One arrangement may be suitable for driving an alternator under varying load at constant speed, while another may be more suitable for driving a ship’s propeller where the power varies as the cube of the speed.

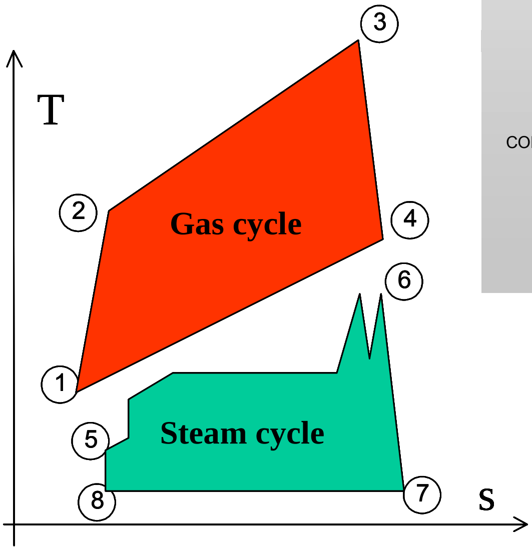
Apart from variations of the simple cycle obtained by the addition of these other components, consideration must be given to two systems distinguished by the use of open and closed cycles.

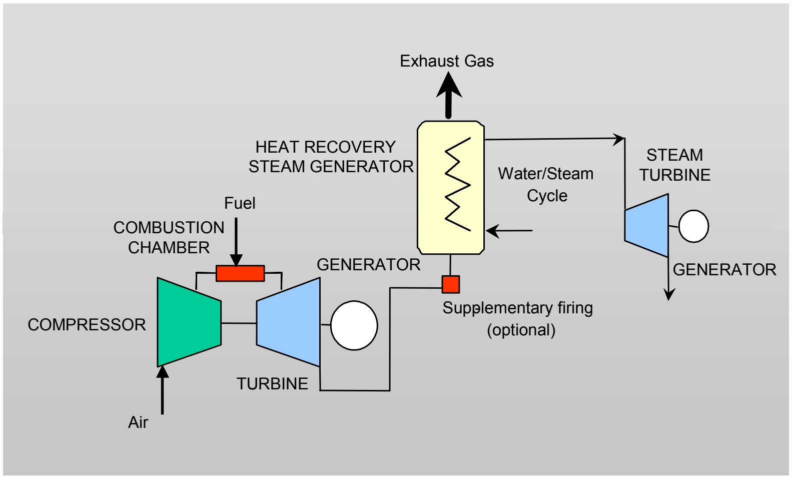
3.1.3 Combined-cycle gas turbines (CCGT)

The previous explanations of the gas turbine process clearly showed that the exhaust gas still leaves the turbine with a high temperature. In the case of an improvement of the simple cycle, this heat potential can be partly utilized by means of recuperative heat exchange (HRSG – Heat Recovery Steam Generator).

This heat potential can be used even more efficiently, if the gas turbine is combined with other plants. A steam process is connected to the gas turbine process in order to achieve an increase in power and efficiency, because the exhaust gas temperature of present gas turbines is higher than the turbine inlet temperature of a steam process. In order to meet the demand for heat, the heat contained in the exhaust gas can be exchanged to a district heating network in a waste-heat boiler

The advantage of the gas turbine process lies in the heat supplied at a high temperature level. The high exhaust gas temperature is disadvantageous. The turbine inlet temperature of the steam process is limited by the material technology and has a relatively low temperature level. The extraction of the heat at a low temperature level is advantageous. Combining both processes, the advantages of each can be used.





1-2	Compressor
2-3	Combustion chamber
3-4	Turbine
5-6	Heat Recovery Steam Generator
6-7	Steam Turbine
7-8	Condenser

Figure: Heat exchange of a combined cycle

The description of the combination of a gas and steam turbine in a T,S-diagram (see figure above) shows the transfer of heat contained in the gas turbine´s exhaust gas to the steam cycle by a heat exchanger. This results in the heating up of the water in the steam cycle followed by evaporation and superheating of the steam. Therefore, a required minimum temperature difference between the exhaust gas and the steam must be maintained. In general this state exists at the boiling point of water. The super-heated steam expands in the steam turbine.

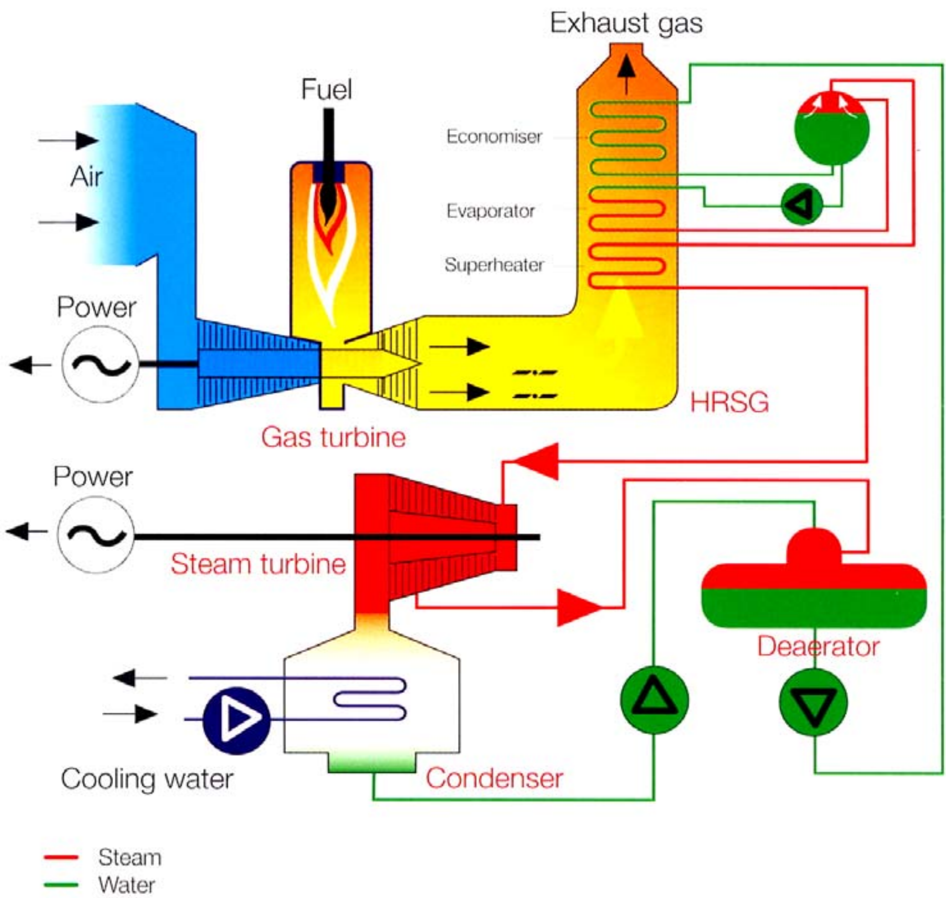


Figure: Combined Cycle Power Plant

The rise in power and efficiency achieved by combining both processes is based on the additional effective power available through the steam turbine process.

The schematic description of this combined gas and steam turbine process is shown in the figures given above. The gas turbine process consisting of a compressor, a combustion chamber and a turbine is combined with a waste-heat boiler used as a heat exchanger in which the water is transformed into steam by a pre-heater, an evaporator, and a superheater. The steam flows through the turbine and is condensed to water in a condenser. This combination of processes is the most efficient of all thermal power plants.

A rise in the effective power of the total cycle can be achieved by heating the exhaust gas of the gas turbine by means of a supplementary firing. In the heat exchange with the steam process the exhaust gas is available at a higher temperature with the result that the turbine inlet temperature can be increased. Consequently the steam turbine delivers more power than a steam turbine operating in the unfired process.

3.1.3.1 Emission control from gas-fired turbines and combined cycles

Abatement of dust emissions

Fuel dust contained in natural gas is washed out at the production site if necessary. Dust or particulate matter emissions from gas turbines burning natural gas are not an environmental concern under normal operation and controlled combustion conditions.

Other gases, such as the by-products of chemical plants, can contain dust. These gases are required to meet different emission limit values compared to natural gas and must be burned or co-combusted in power plants equipped with primary and secondary measures to reduce the dust emissions if these limits cannot be met.

Abatement of SO_2 emissions

Fuel sulphur in natural gas in the form of H_2S is washed out at the production site. Thus, fuel qualities are obtained which directly meet SO_2 emission limit values for all applications. Other gases, e.g. as by-products of chemical plants, can contain sulphur. These gases are required to meet different emission limit values compared to natural gas and must be burned or co-combusted in power plants equipped with FGD technology if these limits cannot be met.

Abatement of NOx emissions - Water or steam injection

Since dry low-NOx combustors (DLN) have reached an acceptable state of development, water/steam injection has become used in Europe, although only to a minor degree so far, as a NOx reduction measure. However, for existing installations, it is the most easily applicable technology, and may be applied in combination with other NOx abatement measures. In Canada, about half of the gas turbines with NOx control are equipped with steam/water injection.

Water/steam injection can be performed either by the injection of a mixture of fuel and water or steam or by the injection of water or steam through nozzles directly into the combustion chamber. The evaporation or superheating of steam requires thermal energy, which is then not available to heat the flame. Thus, the flame temperature decreases and NOx formation also reduces. The emission reduction rate strongly depends on the amount of water or steam used. In order to reach high emission reduction rates, large amounts of water or steam are necessary. Sometimes the amount of water or steam injected is higher than the amount of fuel burned. A higher emission reduction rate can be achieved with water than with steam (for a given water or steam-to-fuel ratio), which can be explained by the fact that more energy is required to evaporate the water (in practice approximately twice as much steam is necessary to achieve the same NOx emission reduction). Water injection is often used when steam is not available, e.g. in simple cycle applications and in pipeline compression, whereas steam injection is usually preferred on natural gas fired combined cycles, where steam is readily available from the exhaust heat recovery system.

The steam, or water, injected into gas turbines needs to be of very high purity, which requires the use of high quality water treatment plant, which in turn may create a liquid effluent requiring disposal. Also, the steam or water needs to be injected at high pressures, usually 20 bar or greater. The use of steam or water injection may also reduce the life expectancy of a gas turbine.

Emission reduction rates between 60 and 80 % can be achieved but without limiting CO. If CO emission limit values are observed, NOx reduction rates between 40 and 60 % can be achieved. The steam/water to fuel ratio depends on the gas turbine type (e.g. for flame) and it varies between 1 to 1.2. NOx emissions can be reduced to approximately 80 – 120 mg/Nm3 (at 15 % O2).

The injection of water or steam has an influence on the general gas turbine parameters, such as the output, efficiency, and the exhaust mass flow. For example: the efficiency of a gas turbine is reduced through water/steam injection, and flame stability problems can be observed at high water-to-fuel ratios.

The investment costs for retrofitting gas turbines with water or steam injection can vary widely. They are mainly related to the water conditioning and injection devices used. The additional operating costs incurred by the water/steam injection are due to an increased fuel consumption.

Some major drawbacks of this NOx abatement technique are the increased emissions of CO and hydrocarbons, a decrease in the thermal efficiency of the installation, and an increase in fuel consumption. Steam injection causes a greater efficiency loss than water injection (3 – 4 % for water injection). Furthermore, direct injection of water or steam results in a higher material stress (small fissures can occur on the material surface due to temperature shock) than injection of a fuel/water or steam mixture. As a consequence, the latter alternative is preferred.

The emission levels can vary a lot, depending on the load of the turbine. In many installations, the steam can be produced only in higher loads, which means that emissions will be reduced only after this base load level has been reached. This makes steam injection of little use for gas turbines with lots of load changes. A steam injection retrofit for a 140 MWth gas turbine costs about € 1.7 million.

<u>Abatement of NOx emissions - Dry Low-NOx (DLN) technologies</u>

Currently, dry low-NOx combustors are applied for large gas turbines, and seem to be becoming more widespread in small facilities (e.g. gas turbines with capacities even below 20 MWe). DLN technology has recently also been applied to gas turbines operated offshore.

The basic characteristic of dry low-NOx combustors is that the mixing of the air and fuel and the combustion take place in two successive steps. By mixing combustion air and fuel before combustion, a homogeneous temperature distribution and a lower flame temperature are achieved, resulting in lower NOx emissions. Currently, dry low-NOx combustors represent a well-established technology, especially for gas turbines using natural gas.

Dry low-NOx combustion systems are very effective and reliable. Today, almost all gas turbines in industrial use are equipped with dry low-NOx systems. Modern dry low-NOx burner retrofits cost appr. € 2 million for a 140 MWth gas turbine. Due to their high efficiency, new burners are very economical to operate, especially as there are no big losses of energy from fuel losses, or in the form of hydrocarbons etc.

<u>Selective Catalytic Reduction (SCR)</u>

Many gas turbines currently use only primary measures to reduce NOx emissions, but SCR systems have been installed at some gas turbines in Austria, Japan, the Netherlands and in the US (especially in California). It is estimated that approximately 300 gas turbines word-wide are equipped with SCR systems.

3.1.4 Oil fired gas turbines

Gas turbines fuelled with liquid fuels as the main fuel (not as the back-up fuel) are very rarely applied in Europe, due to the extensively high costs of such fuels, mainly light distillate oil; and the stress imposed by liquid fuels on gas turbine blades and rest systems compared to natural gas. Therefore, applications are very rare and only exist in those cases where a natural gas supply does not exist. Two types of liquid-fuel-fired gas turbines are currently applied: heavy-duty gas turbines and gas turbines derived from aeroplane engines, so-called aeroderivatives.

By means of an axial compressor, pressurised air is driven into the combustion chambers, where the fuel injectors are connected. During the combustion reaction, the gas temperature rises, and at between 1000 °C and 1350 °C it is introduced into the turbine. These hot gases are depressurised in the turbine, which simultaneously drives both the air compressor and the alternator, which in turn generates electricity. In the “open cycle” configuration, the combustion gases are released directly into the atmosphere at a temperature of >450 °C. The thermal efficiency is then between 30 and 40 %.

Gas turbines (GT) can operate with a wide range of liquid fuels, such as residual fuel naphtha. Gas turbines in general and aeroderivatives in particular run on light distillate fuel oil or on kerosene. For recent designs of turbines, which have high turbine inlet temperatures, the manufacturers’ specifications for fuel supplies are very stringent. They stipulate the physical and chemical properties needed in order to meet both the equipment demands and the environmental standards, particularly with regard to metal contaminants (sodium, potassium, lead, vanadium, calcium), sulphur and ashes.

3.1.4.1 Emission control from oil fired turbines

Abatement of SO_2 emissions

Switching to low-sulphur oil can make a significant contribution to SO_2 emissions reduction. The sulphur content of light fuel oil used in gas turbines is determined by the relevant Directive 93/12/EEC (relating to the sulphur content of certain liquid fuels valid in the EU), and should be below 0.05 %. This very low sulphur content ensures low emissions levels of SO_2 from gas turbines fuelled by light distillate oil.

Abatement of NOx emissions

NOx formation can be restricted by decreasing the combustion temperature. This is accomplished by the pre-mix burner technique, where fuel is blended with the combustion air in order to avoid excessive peak flame temperatures. This, however, only operates when the unit is operating near full load. A different combustion method must be applied for part-load operation, start-up and shutdown, in order to avoid flashbacks. Steam injection and water injection are also used to reduce combustion temperatures and consequently NOx.

Applying stage combustion in gas turbines at lower temperatures needs a different design of gas turbines as two pressure stages with separate fuel supply are needed.

Wet reduction processes: Water or steam is injected into the combustion chambers in order to reduce the combustion temperature, thus avoiding the formation of thermal NOx. For gas turbines

(GT) operating in the “open cycle” system, water is used for injection, whereas for GTs operating in a “combined cycle” or cogeneration system, steam is more often chosen for the injection.

Some gas turbine combined cycle plants in Europe, particularly in Austria, France, Germany, Italy, and the Netherlands, have also applied SCR systems to reduce NOx emissions.

3.2 Gas / oil fired steam turbine power plants

3.2.1 Oil fired steam boilers

Boilers designed for burning liquid fuels such as heavy fuel oil are very similar to boilers that are used for the combustion of coal. A typical heavy fuel oil boiler is shown in the Figure below.

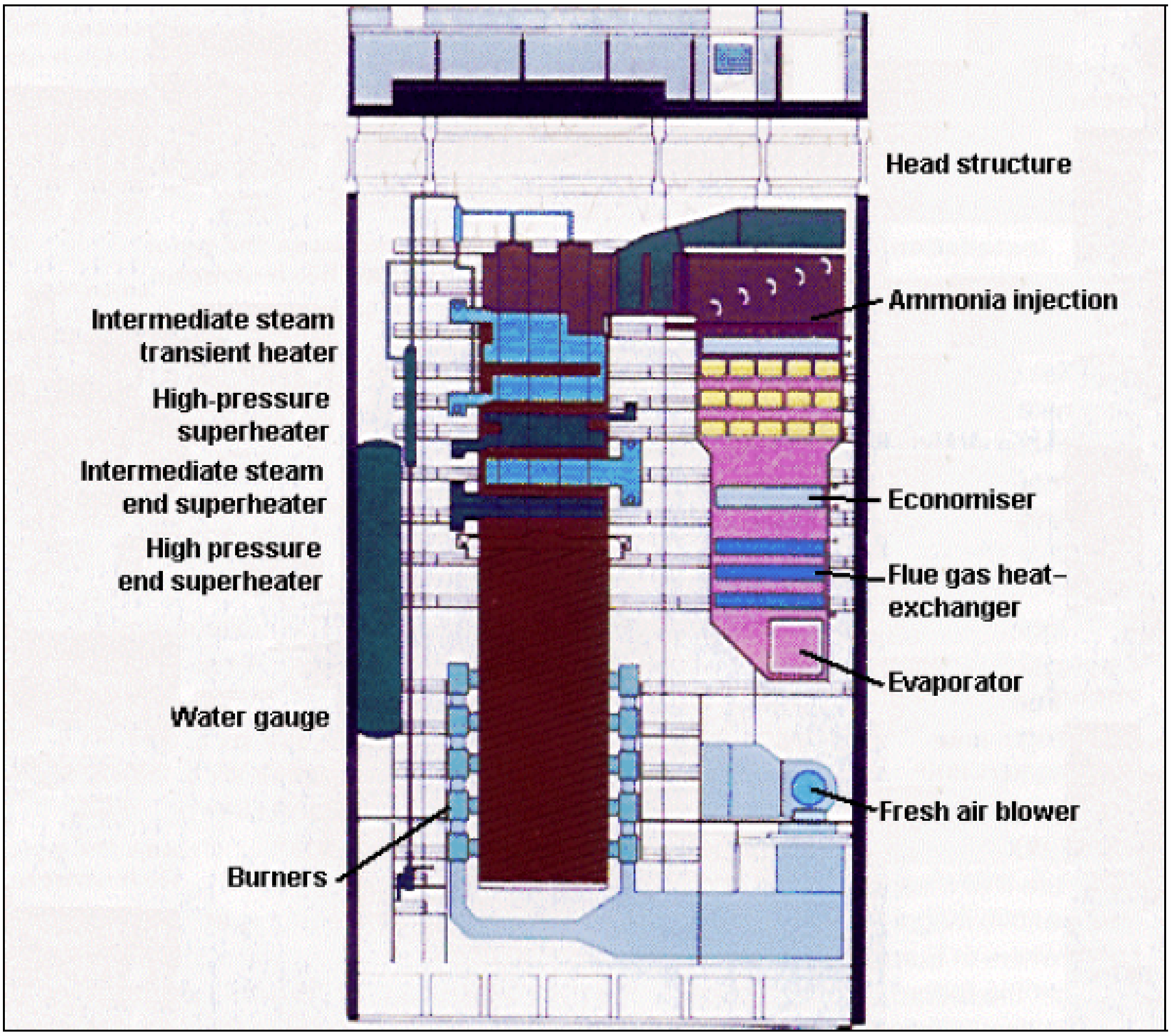


Figure: Sketch of a heavy fuel oil fired boiler

3.2.1.1 Firing systems

The firing systems used in liquid fuel combustion boilers are similar those used in combustion plants where coal is used as a fuel. To achieve a homogeneous combustion, fine aerosol droplets measuring from 30 to 150 µm are sprayed into the boiler by a mechanical process, or through the action of an auxiliary fluid (air or steam) under pressure, or even through a combination of both.

All burner designs are supplied directly with air. When heavy fuel oil is used, low viscosity is needed at the burner, in order to ensure correct atomisation of the fuel. To obtain this viscosity, the heavy fuel oil must be heated to around 120 - 140 ºC. Additives are used to improve the combustion of heavy fuel oil.

Wall- or front-firing systems: In horizontally wall-fired systems the fuel is mixed with combustion air. The burners are located in rows, either on the front wall only or on both the front and rear walls. The latter arrangement is called ”opposed firing”.

Tangential- or corner-firing systems: The tangentially-fired system is based on the concept of a single flame envelope. Both fuel and combustion air are projected from the vertical furnace corner windboxes along a line tangent to a small circle.

There are three major technical issues that need to be taken into consideration when firing heavy fuels:

- the need for heated storage, transportation and additional heating before atomisation, due to the high viscosity of the HFO
- its tendency to form coke particles
- the formation of corrosive deposits

The first two points are caused by the high molecular weight and the asphaltene nature of some of the constituents. The second and the third points stem from the presence of sulphur, nitrogen, vanadium and other metals in the fuel.

With emulsions, the physical effects of a water addition lead to better combustion properties by improving the atomisation. Micro-explosions are produced as a result of the formation, growth and bursting of vapour bubbles within the superheated droplet. Since the oil can sustain very high temperatures during combustion, the water droplets can be superheated. The emulsion droplet is eventually shattered by the internal formation of water bubbles and their rapid vaporisation. This process is called secondary atomisation, and increases the evaporation surface area and the mixing of the burning species in air. The amounts of particulates and smoke formed are minimised.

3.2.1.2 Control of emissions to air

When using heavy fuel oil (HFO) emissions of NOx and SOx, which lead to air pollution, arise from the sulphur and to a certain extent from the nitrogen contained in the fuel. Particulates originate mainly from the ash content and marginally from heavier fractions of the fuel. The presence of particulates can also lead to higher operational costs, resulting from losses due to the unburned fuel and from deposits in combustion facilities, if the equipment is not well maintained.

Abatement of particulate emissions

Particulate emissions from the combustion of heavy oils may contain two major fractions:

1. Material arising from the organic content of the fuel and its failure to complete the burn-out process:
   - unburned hydrocarbons (smoke)
   - particulates formed via gas phase combustion or pyrolysis (soot)
   - cenospheres produced from cracked fuel or carbon along with ash (coke).
2. Ash from the inorganic content of the fuel:

Smoke may arise from unburned fractions of hydrocarbon fuel exhausted in the form of a fine spray. Such hydrocarbon fractions are the remainders of reactions frozen by thermal quenching. Emissions of unburned hydrocarbons are highest at high equivalence ratios (fuel-rich conditions). Their main environmental effect is their reactions in the atmosphere with NOx and sunlight to form photochemical smog.

Soot is formed in gas-phase reactions of vaporised organic matter in a complex process involving fuel pyrolysis, polymerisation reactions, nucleation, particle growth and burn-out. Fuel droplets burning in envelope flames are subjected to very high temperatures, leading to fuel evaporation and thermal cracking of the large molecular structures, thus resulting in species of higher C/H ratio than the fuel source. Soot is most likely to be formed in fuel-rich conditions, and is normally fully burned as it mixes with air at a very high temperature in highly oxidising zones, e.g. as secondary air is injected into the combustion chamber of a gas turbine.

Coke particulates are formed in liquid-phase processes, and contain all the non-soot carbon and also part of the ash material. Such particles are nearly spherical, hollow and porous, and they range in size from 1 to 100 μm.

Ash fouling and corrosion are major problems when burning heavy oils. Vanadium and sodium are the most harmful elements, respectively forming vanadium pentoxide (V2O5) and sodium sulphate (Na2SO4). Ash deposits jeopardise heat transfer to metallic surfaces and cause corrosion of the combustion hardware, thus decreasing the equipment lifetime. In gas turbines, ash reduces the aerodynamic path for the gas flow, and therefore the turbine performance. Values given in the literature show that a mere 0.32 cm thick deposit can cause a 10 % decrease in turbine power.

Solid particulates cause corrosion, erosion and abrasion, all of which reduce the lifetime of the hardware. Carbon particulates may also increase the radiative power of the flame, causing damage to the combustion chamber materials. In addition, there is an economic loss from losing unburned material to the atmosphere, which therefore means a decrease in fuel efficiency.

Because of the effects mentioned above optimum combustion conditions are important for the minimisation of particle and ash production. Viscous fuel oil can be atomised by preheating the fuel. Additives combine with fuel constituents and combustion products to form solid, innocuous products that pass harmlessly through the combustion equipment and may be used to support the optimum combustion conditions. In older oil-fired boilers, burners with mechanical atomisation were installed. The improved design of burners with steam atomisation gives a more efficient combustion of HFO, and results in lower particulate emissions. PM emission concentrations in the raw gas (before dedusting) of lower than 100 mg/Nm3 may be achieved, though this depends greatly on the ash content of the HFO.

Particulate emissions are normally reduced by ESPs. Particles are generally collected in an ESP in a dry form, which can then be landfilled in controlled landfills. The ash resulting from fuel oil combustion presents a high content of unburned carbon. This ash can therefore be incinerated (in industrial kilns), or can be re-injected into the combustion chamber of a boiler. Fly ash from oil firing installations is regarded as hazardous waste.

Abatement of SO_2 emissions

Sulphur is usually found in hydrocarbon fuels, normally up to a maximum of 3 % by weight, and mostly in organic form, although it also exists as inorganic compounds. Heavy fuel oils usually contain higher amounts of S than other petroleum products, as it tends to concentrate in the residue along with asphaltenes during the refining processes.

At the high temperatures and oxygen concentrations typical of combustion, sulphur combines with carbon, hydrogen and oxygen to form SO_2, SO_3, SO, CS, CH, COS, H_2S, S and S_2. Under such circumstances almost all of the sulphur is in the '+4' oxidation state, hence SO_2 is the predominant sulphur compound formed in combustion. Even with a 20 % air deficiency, 90 % of the sulphur is in the form of SO_2 and as little as 0.1 % is as SO3; with SO accounting for the remainder of the sulphur.

At lower oxygen concentration (40 % deficiency) H_2S, S_2 and HS are also present in significant proportions, while SO3 is negligible. During combustion these species are in super-equilibrium concentrations. As the gases cool, their rates of consumption decrease and equilibrium may be "frozen" before the products reach room temperature.

In oxygen-rich flames, i.e. normal operation in combustion facilities, SO and SO_3 are present, as well as H_2SO_4 as a result of the combination of SO_3 and H_2O. Sulphuric acid is responsible for corrosion in combustion equipment. This is a major reason for controlling sulphur combustion.

Switching to low-sulphur oil might be a technique which can make a significant contribution to SO_2 emissions reduction. A decrease of 0.5 % in the oil sulphur content leads to a decrease in the emission value by about 800 mg/Nm3. To reduce SO_2 emissions from liquid-fuel-fired boilers, especially those burning HFO, some plants apply wet scrubbers. The figure below shows a wet scrubber applied to an Austrian HFO fired boiler.

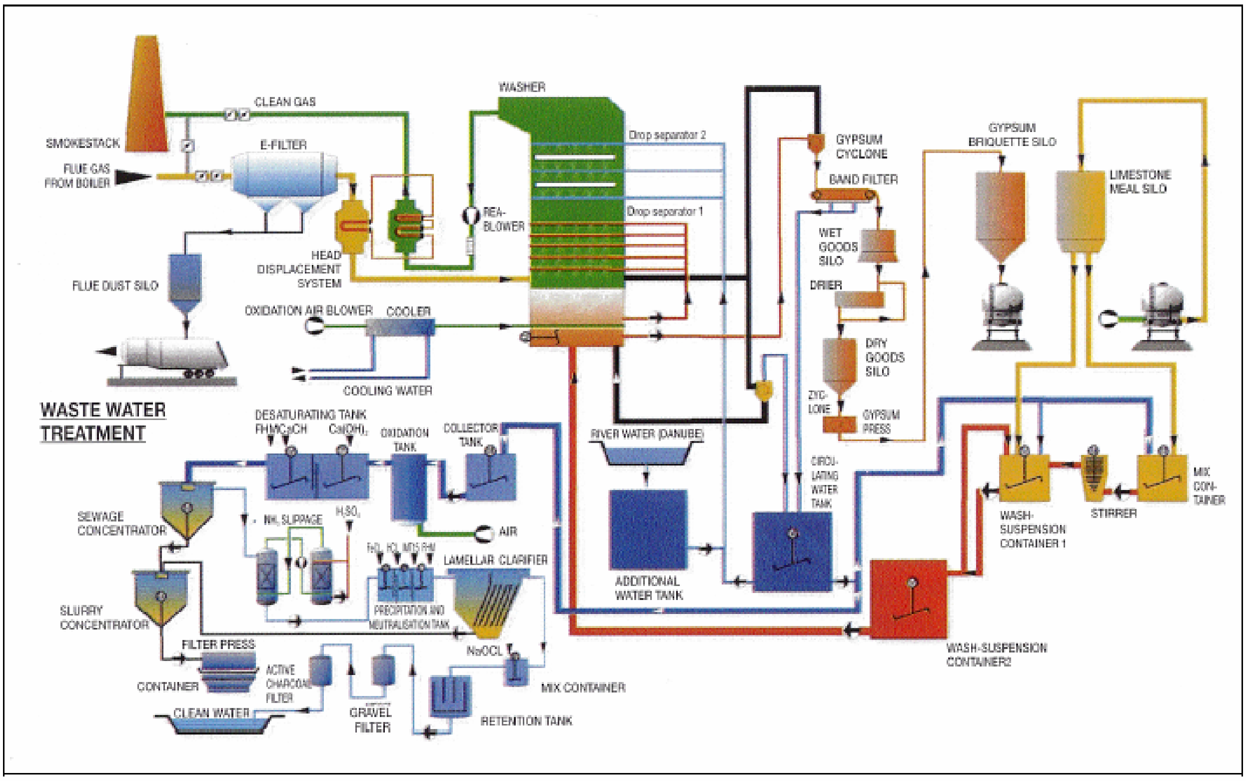


Figure: Wet FGD process applied to a HFO fired boiler

<u>Abatement of NOx emissions</u>

With conventional fuels, the NOx formation rate very much depends on the gas temperature and the amount of nitrogen in the fuel. Both characterise the most important routes for the formation of NOx. The thermal NOx can be controlled through a reduction of the flame peak temperature (e.g. limited combustion chamber load). The quantity of fuel nitrogen must also be considered and should be limited in supply contracts if necessary. The NOx concentration in the exhaust of an oil-fired boiler indicates that the NOx concentration decreases with excess air. The boiler size also plays an important role in the concentration of NOx in the flue gases. Factors such as the method of firing have little influence.

For oil-fired boilers, the usual excess air is in the range of 2 - 4 % O_2 (in flue gas). A low excess air combustion will be characterised by 1 - 2 % O_2. This technique is rarely used alone, but is very often used in combination with 'Low-NOx burners' or 'Overfire Air'.

Flue gas recirculation is more often used in oil- or gas-fired boilers than in coal-fired ones. The higher combustion temperature improves the NOx reduction through the addition of cold clean flue gas. This technique is often used in combination with low-NOx burners and/or OFA, together achieving a 60 - 75 % reduction from the original NOx emission baseline level.

Amongst all the air staging techniques, the most commonly used in oil-fired boilers are 'burners out of service' (BOOS) and 'Overfire Air' (OFA). With modern OFA designs (optimised nozzle design, separated and swirled air flux), the NOx reduction can be as high as 60 % in tangential firing units.

Flue gas recirculation type burners are used in oil-fired boilers, matched with the various types of Low-NOx burners (LNB) and achieves a corresponding NOx emission reduction of 20 %. The key point in designing an efficient oil LNB is to ensure a good oil atomisation coupled with the burner aerodynamics, so as not to increase the carbon-in-ash level while decreasing NOx. Modern LNB designs with a proper oil atomisation system can reach a 50 % NOx reduction. For oil-fired plants in general, the NOx emission reduction limits with low-NOx burners are 370 - 400 mg/Nm3 (at 3 % O_2).

In oil-fired boilers, reburning can be implemented with gas or oil as the reburning fuel. Gas is more commonly used than oil. Reburning is interesting for new power plants but is less adapted to existing units. Many existing oil-fired boilers have been equipped with gas/oil reburning during recent years (e.g. Italy has units from 35 to 660 MWe). It is important to note that these units have all been equipped with at least OFA and flue gas recirculation at the same time, and some of them with low-NOx burners. The share of the reburning fuel is 10 to 15 % of the total thermal input. The corresponding NOx reduction is 55 - 80 % from the original NOx baseline level for oil reburning and 65 - 80 % for gas reburning.

Secondary measures such as SNCR and SCR systems have been applied to a number of oil-fired combustion plants. In Europe, SCR systems are applied, in particular, in Austria, France, Germany, Italy and the Netherlands, whereas outside Europe they are mostly applied in Japan. The SCR technology has proven to be successful for liquid-fuel-fired power plants.

3.2.2 Gas fired steam boilers

The large gas-fired boiler design is similar to that of the oil-fired boilers as described in the previous chapter. The heat from the combusted fuel is used for the production of superheated steam, which expands in a steam turbine that drives a generator. In order to efficiently convert the energy from the steam to electricity, modern gas fired boilers use supercritical steam parameters, which produces plant efficiencies of up to 48 % in the condensing mode and fuel utilisation figures of 93 % at combined heat and power production. The application of double reheat and increase of the supercritical steam parameters to 290 bar and 580 °C can reach these high efficiencies.

The burners of the boilers are in general arranged in several levels in the walls (front firing or opposed firing) or at several levels tangentially in the four corners of the boiler. Firing systems for gas-fired boilers are similar to coal- or oil-fired boilers.

3.3 Refurbishment of oil to gas fired gas power plants

Recently in Peru a power plant has been refurbished to replace the use of diesel and convert to natural gas. The owner of the plant is Empresa de Generación Termoeléctrica Ventanilla S. A. (ETEVENSA), Lima. The installed power of the diesel fired plant amounted to totally 340 MW with 2 units, 170 MW each. The diesel fired turbines have now been converted to gas fired and are operating with natural gas since the end of August 2004. Typically the effective capacity was reduced by the measure to now 325 MW (production: 2002: 9.52 GWh; 2003: 6.15 GWh) which is 15 MW lower than the prior nominal figures with diesel. This is due to the different heat and radiation properties of gas flames and the respective adjustments to be made in the control systems. In order to improve the efficiency and the power output again the owner is planning to install a heat recovery boiler to establish a combined-cycle system.

In Peru there are three other power plants also interested in refurbishing to use natural gas. Countries of the Southern Cone plan as well the elimination of oil fired plants by converting the plants to natural gas firing.

Activities like these are re-powering measures which supplement either an existing gas turbine plant (in line with a swap from diesel / fuel oil to natural gas) by adding heat recovery boiler(s) or an existing steam power plant by adding gas turbines and heat recovery boiler(s) in order to realise a gain in overall power output and efficiency. Principally, it consists of transforming an existing conventional power plant into a combined-cycle system, as pure combined-cycle re-powering results in the most efficient arrangement.

For re-powering a steam power plant the following 3 main technologies are available that are based on commercially proven experience:

- Heat recovery re-powering / pure combined cycle re-powering
- Condensor / feedwater heater re-powering
- Boiler windbox re-powering

3.3.1 Heat recovery re-powering

Heat recovery re-powering systems are the most common application of re-powering. These systems utilize gas turbine exhaust energy to generate steam in a heat recovery steam generator (HRSG), thus displacing the power boiler in the existing steam plant. The design can comprise a single throttle pressure non-reheat cycle in which all of the existing steam cycle feedwater heaters are utilized. Other cycles can be designed for increased efficiency using two- or three-pressure HRSG configurations with and without feedwater heaters.

The high exhaust temperature of advanced technology gas turbines makes re-powering a reheat steam turbine an economically viable option. Options using a three pressure level reheat HRSG are receiving considerable attention as utilities enhance use of existing sites.

A multi-pressure combined-cycle system can be accommodated by existing steam turbines that have multi-flow low-pressure sections since the crossover pipe from the intermediate-pressure section to the low- pressure section can be readily modified to accept the low-pressure steam admission. The intermediate-pressure steam is admitted to the cold reheat piping which is part of the re-powering system. If the economic evaluation requires a lower cost system, it can be provided by a two- or single-pressure system with higher heat rate.

Since combined cycles achieve highest efficiency with no extraction feedwater heaters and multiple low-pressure admissions, the throttle flow of the re-powered steam turbine must be reduced relative to its design to maintain the same exhaust flow and heat rejection to the condenser cooling water. Further, the pressure drop between the HRSG superheater discharge and the steam turbine nozzle should be minimized for highest combined-cycle efficiency. Therefore, the re-powered steam turbine should operate with valves open in a sliding pressure mode. Since the throttle flow is reduced about 25%-30% to maintain the design condenser flow, the steam pressure would be similarly decreased. Since the combined-cycle heat rate is relatively insensitive to steam pressure, the reduced steam pressure does not significantly increase the plant heat rate. Economics may justify steam turbine modifications to improve efficiency in some applications. The performance change is application specific and depends on the match of the new gas turbine with the existing power plant. Because heat recovery re-powering leads to the largest improvements in net plant output and heat rate, most of the industry focus today is on this re-powering approach.

3.3.2 Condensor / feedwater heater re-powering

In a fossil steam plant, approximately 20% to 30% of the throttle steam flow is typically used for feedwater heating. If the feedwater heating duty was supplied by the gas turbine exhaust energy, then additional steam would be available for passing through the entire length of the steam turbine. In practice, the amount of additional steam passing ability is limited by the exhaust loading of the steam turbine, the heat rejection duty of the condenser or cooling towers and/or the site license discharge limits. The gas turbine is used to heat feedwater in the economizer before the feedwater enters the boiler. Feedwater to the economizer can be taken from the condenser or following any combination of heaters. The greatest improvement in cycle heat rate occurs, if all existing feedwater heaters are displaced.

3.3.3 Boiler windbox re-powering

Boiler windbox re-powering systems utilize gas turbine exhaust gas as preheated combustion air in the existing boiler. In this application, the hot, oxygen-rich gas turbine exhaust gas provides the function of the forced draft fan and air heater. The heated combustion air reduces the boiler fuel requirements.

Windbox re-powering displaces the air preheater and would result in a high stack gas temperature, if no modifications of the boiler heat recovery sections were made. In most instances, additional economizer surface will be added to the boiler, transferring this duty from the steam turbine extraction cycle to the boiler, in order to arrive at a reasonable stack gas temperature for the re-powered configuration.

Additional issues in this form of re-powering include the quantity of gas turbine exhaust flow relative to boiler needs, the exhaust pressure losses imposed on the gas turbine, and possible steam system derating due to the reduced oxygen content from turbine exhaust gases relative to ambient air.

3.3.4 System selection factors

The selection of the most economic re-powered configuration for a specific application is dependent upon many factors. These include:

Fuel	Natural Gas Light Distillate Oil Coal
Duty Cycle	Base Load Mid-Range Daily Start-Stop
Steam Plant	Non-reheat Reheat Turbine Size Type of Cooling Cooling Water Temperature
Environmental Requirements	Emissions Thermal Discharge
Economic Factors	Fuel Cost Interest Rate Fixed Charge Rate Life of Plant

The most appropriate configuration has to be decided individually for each project.

3.4 Cleaner coal technologies

There exists a wide diversity of technologies for cleaner power generation from coal. Generally, it can be differentiated between three main industrially developed types of clean coal technologies:

- Supercritical Pulverised Fuel
- Fluidised Bed Combustion
    - Atmospheric Fluidised Bed Combustion
    - Pressurised Fluidised Bed Combustion
- Integrated Gasification Combined Cycle

A standard way of classifying power generation technologies, based on the characteristics of the environment in which the fuel releases its energy content, is shown in Figure 1.

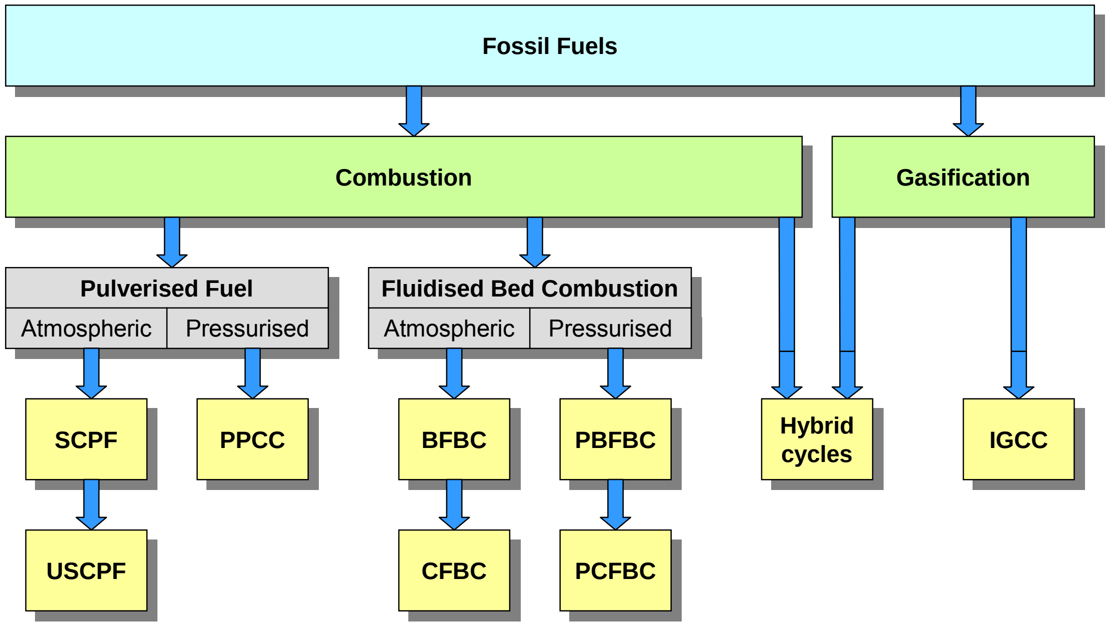


Figure 1: Main types of fossil fuels based power generation technologies

As far as the steam side is concerned, all of these technologies are based on a conventional steam turbine/generator - the problems are similar in each case. Different is the fuel/flue gas path, where each technology has its own peculiarities and technological problems to be solved. There are also many new processes, at varying stages of development and maturity, gradually moving from the desktop, to laboratory, to demonstration and thereafter to commercialisation.

3.4.1 Pulverised Fuel - PF

Since its introduction in the 1920s, pulverised fuel (PF) combustion has been the mainstay of coal-based power generation and is likely to dominate the market well into the future. Over the years, PF technology has been the subject of continuing development effort, but perhaps the most significant recent development has been the introduction of advanced boilers capable of operating under supercritical steam conditions.

In PF combustion fuel is blown with air into a boiler furnace. There are “sub-critical” (SCPF) and “supercritical” (USCPF) boilers. PF boilers are termed “sub-critical” if the steam generated is below the critical pressure of 221.2 bar. Above this pressure, there is no distinct water/steam phase transition, and the boiler is said to be “supercritical”. Compared with sub critical power generation, the increased thermal efficiency of supercritical boiler technology has brought benefits of reduced fuel consumption and reduced emissions of harmful pollutants. As a result, supercritical steam cycles have gained rapid acceptance in OECD countries, with some 19.4 GWe of supercritical plant commissioned between 1995 and 1999 compared to just 3.0 GWe of sub-critical capacity.

In PF combustion, coal is finely ground and then blown with air through a number of burners into a boiler furnace. The coal burns and the heat released is used to produce high-pressure superheated steam. This is then used to drive a steam turbine/alternator set to produce electricity. Boiler units are typically large (300-1000 MWe) and matched with a single dedicated turbine/alternator set.

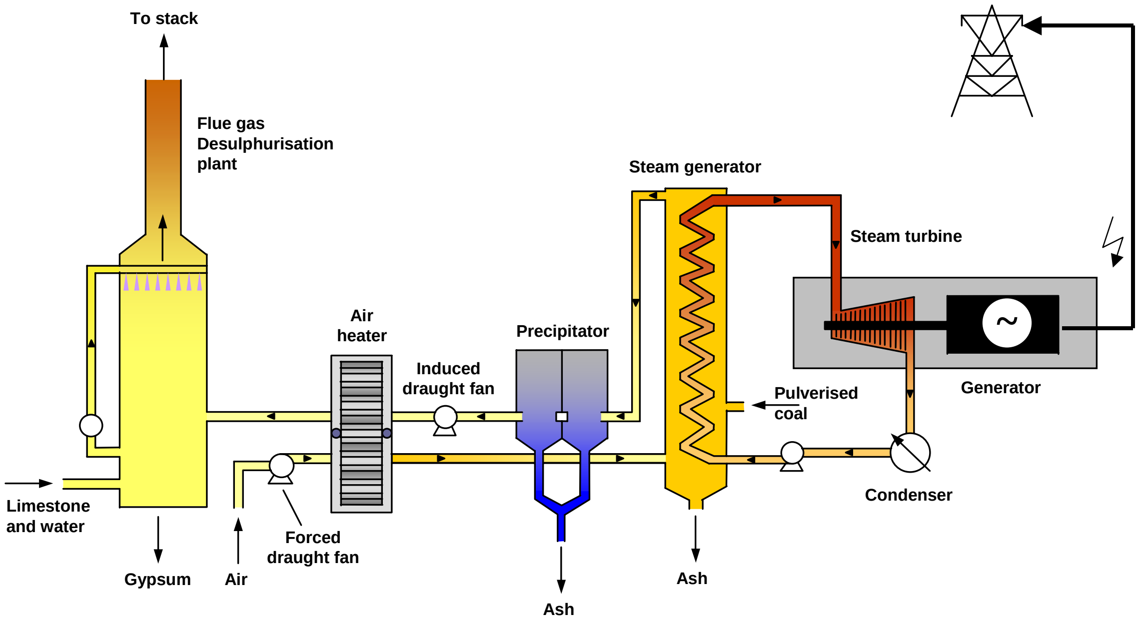


Figure 2: Schematic diagram of a typical PF power plant

Another type of PF power plant is the pressurised pulverised combustion of coal (PPCC). This type of power plants is currently under development, mainly in Germany. It is similar to conventional pulverised coal combustion, in that it is based on the combustion of a finely ground cloud of coal particles, the heat released from combustion generates high pressure, high temperature steam, which is used in steam turbine-generators to produce electricity. The pressurised flue gases exit the boiler and are expanded through a gas turbine to generate further electricity and to drive the gas turbine's compressor; hence this is a form of combined cycle power generation. This technology is currently at a developmental stage and is not widespread.

Currently, the state-of-the-art supercritical pf plants currently operate at up to 300 bar and 600ºC, with net efficiencies ~45%, depending on coal type and plant location. Ålborg Power Station Unit 3 at Vendsysselværket, Denmark - a double-reheat supercritical 285 bar/580ºC, 412 MWe coal-fired plant - currently achieves 45.1% efficiency.

Steam conditions and cycle efficiencies continue to improve steadily. By 2020 650-700ºC is expected to be commercially available, with cycle efficiencies in the range 50-55%. About half this efficiency gain is expected to come from enhanced steam conditions and the rest from reduced plant losses (e.g. lower flue gas exit temperatures, higher feed water temperatures, lower pressure drops, better combustion, more efficient auxiliaries) and improved operating methods. Table 1 shows a classification of pulverised coal power plants.

Table 1: Classification of pulverised coal power plants according to UNIPEDE

Category	Subcritical	Supercritical Advanced	Supercritical	Ultra Supercritical
Year	<1990	1990-1995	1995-2000	>2000
Live steam pressure [MPa]	16.5	22.1	27.5-30	30
Live steam temperature [ºC]	540	540-560	560-600	>600
Reheat steam temperature [ºC]	–	560	580	>600
Single reheat	–	✓	✓	–
Double reheat	–	–	–	✓
Generating efficiency [%]	~38	~41	~44	46+

Enhanced steam conditions put considerable demands on boiler and steam turbine materials. Work is under way to develop materials with the required strength and ductility that can withstand the highly corrosive and erosive environment pertaining to advanced steam conditions, without it advances will be forfeited. Currently, a number of new ferritic and austenitic steels are being investigated for applications up to 650ºC, whilst nickel (Ni)-based alloys are under consideration for 700ºC and above. There are now approx. 100 supercritical pf plants around the world. Besides material developments, the most significant recent advances include double reheating, reduced condenser pressure and improved turbine designs. The replacement of spiral-wound furnace tubing with vertical furnace-wall tubing represents a further imminent advance; this would be both cheaper and easier to install and maintain, and would add to the boiler efficiency through presenting a lower pressure drop.

Pulverised coal can be combusted at high pressure (>20bar) to provide a high-temperature (>~1400-1500ºC) flue gas, which is then expanded through a gas turbine to generate electricity directly. Exhaust gas from the turbine can additionally be used in a steam generator to produce steam for a steam turbine. The approach is not subject to the same maximum temperature limitations as conventional combustion technologies and can, therefore, take full advantage of the higher efficiencies offered by raising the inlet temperature of the gas turbine. **Fehler! Verweisquelle konnte nicht gefunden werden.** shows the most advanced PF installations in Europe, together with data on the boiler.

Table 2: Selected state-of-the-art supercritical steam power plants in Europe

Power Station	Fuel	Output net [MWe]	Steam pressure [bar]	Main steam temp. [°]	Reheat steam temp. [°]	Net efficiency LHV [%]	Year
Avedore (DK)	coal	390	290	580	600	46.8	2001
Boxberg (D)	lignite	907	266	545	581	41.8	2001
Esbjerg (DK)	coal	411	250	560	560	45	1992
Hemweg 8 (NL)	coal	630	260	540	568	42	1994
Lippendorf (D)	lignite	875	267	554	581	43.1	2000
Niederaussem (D)	lignite	965	275	580	600	45.2	2002
Nordjyllands (DK)	coal	411	290	582	580	47	1998
Schkopau (D)	lignite	950	285	545	560	40	1995
Schwarze Pumpe (D)	lignite	1600	267	547	560	41	1998
Staudinger (D)	coal	509	262	545	562	43	1992

One of the world’s largest and most environmentally friendly lignite-fired power plants “Schwarze Pumpe” is situated in the state of Brandenburg, some 60 km northeast of Dresden in Germany. The plant has two 800 MWe units and was built as the first of a series of three plant of this type. The units entered commercial operation between November 1997 and May 1998. The power plant’s most important task is to generate base-load power for the public grid. Designed with extraction condensing turbines, this power plant also supplies district heat to surrounding towns and villages and process steam to the neighbouring briquette factory. The power plant can also provide an immediate reserve of 5% of rated capacity in 30 seconds for grid frequency regulation.

Figure 3: Schwarze Pumpe PF power plant

The units are characterised by supercritical steam conditions, as well as single reheat and variable-pressure operation. They achieve a net electrical efficiency of more than 41% and a fuel utilisation factor of up to 55%. With advanced combustion processes and efficient flue-gas scrubbing systems, plant emissions remain safely within Germany‘s strict statutory limits, and in most cases by a significant margin below it.

3.4.2 Fluidised Bed Combustion

Fluidised bed combustion (FBC) is a method of burning fuel in a bed of heated particles suspended in a gas flow. At sufficient flow rates, the bed acts as a fluid resulting in rapid mixing of the particles. Fuel is added to the bed and the continuous mixing encourages complete combustion and a lower temperature than that of pf combustion.

FBC technology was developed by the oil industry during the 1930s and the principles have been applied to the controlled combustion of solid fuels since the 1960s. When a gas is passed upwards through a bed of fine particles, the velocity of the gas determines the degree of disturbance. At low velocities there is very little particle movement but, as the velocity increases, individual particles begin to be forced upwards until they reach the point at which they remain suspended in the gas stream. Any further increase in gas velocity causes turbulence, with rapid mixing of the particles. A particle bed in this state behaves like a liquid and can be described as “fluidised”. Fluidised bed coal combustion uses a continuous stream of combustion air to create the necessary turbulence. The constant mixing of particles encourages complete combustion and also allows a uniform temperature to be maintained within the combustion zone. The ash produced accumulates in the bed, eventually forming the bulk of the particles. Surplus ash is drawn off at intervals to maintain the bed at the correct level. Most of the heat generated is transferred to a water/steam system, usually via water tubes immersed in the bed.

The principal advantages of FBC power plants can be summarised as follows:

- “in situ” desulphurisation possible already during combustion in the fluidised bed through the reaction of sulphur dioxide with limestone or dolomite sulphur sorbent, forming calcium sulphate;
- limited nitrogen oxide emissions thanks to combustion temperatures which are much lower than in conventional PF boilers, or typically around 850°C, which is below the temperatures where “thermal NOx” can form;
- high heat transfer to immersed boiler tubing, where steam is generated for expansion through a steam turbine, allowing for a compact boiler arrangement;
- high flexibility for use with different ranks of coal, including those with high contents of sulphur and/or ash;
- possibility to burn other low grade fuels, such as biomass, RDF and other waste substances and to perform “co-combustion” of different types of fuels;
- use of crushed fuel with relatively large particles, leading to reduced milling cost.

FBCs fall into one of two main categories:

- Atmospheric-pressure
- Pressurised.

There are two main derivatives of FBC, namely bubbling fluidised bed combustion (BFBC) and circulating fluidised bed combustion (CFBC). There exist also several hybrid systems and also pressurised versions of both BFBC and CFBC. The status of these different systems varies, with some now fully commercial and some still under development.

The possibility of applying fluidised bed combustion technology for the generation of electricity from coal first attracted worldwide interest in the 1960´s. This was especially because it promised to be a cost effective alternative to pf plants, while at the same time allowing sulphur capture without use of add-on scrubbers. As a result, R&D efforts began in the U.S. and in Europe, first with atmospheric bubbling fluid bed (BFB) units, and, when it became apparent that utility size BFBC plants would have very large physical size, also on pressurised fluid bed combustion

3.4.3 Atmospheric Pulverised Bed Combustion - AFBC

Fluidised bed combustion power plants use the same steam cycle as conventional pulverised fuel fired boiler plant. They raise steam via a different combustion technology.

Atmospheric fluidised-bed combustion (AFBC) technology consists of forming a bed of finely sized ash, limestone (for sulphur removal), and solid fuel particles in a furnace and forcing combustion air up through the mixture, causing it to become suspended or fluidised. It is characterised by a lower temperature level resulting in lower achievable efficiencies but, on the other hand, by high fuel flexibility and a low emission level without the need of secondary measures such as catalyst or desulphurisation units.

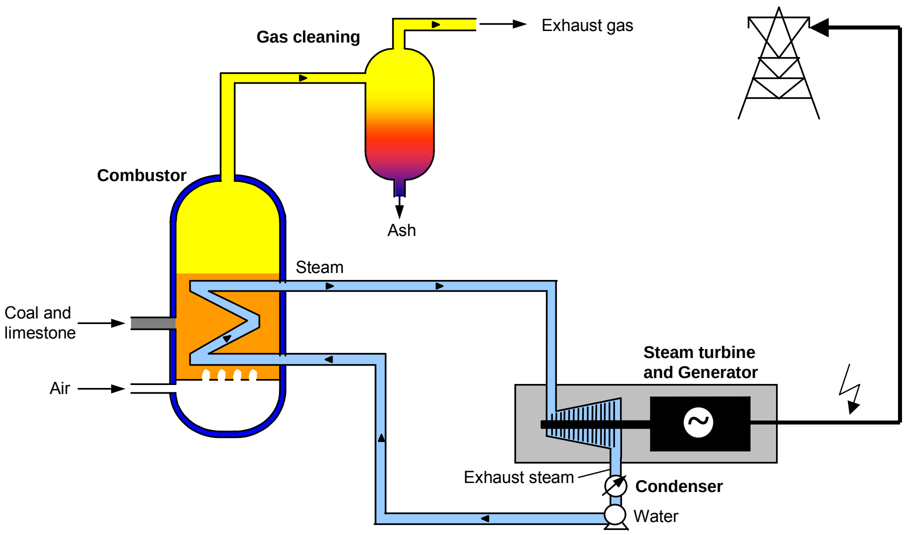


Figure 4: Principle for an AFBC power plant

The process characteristics of AFBC can be briefly summarized as follows:

- The ACFBC process, whereby a coal particle recycle many times in the combustor, ensures a high carbon burn-out and combustion efficiency which would otherwise be altered by the limited furnace temperature.
- However, this limited temperature of about 850°C, which is optimally selected for the most efficient capture of the coal-borne sulphur species, entails a number of advantages, one of which, and not the least, being of minimizing NOx formation.
- The in-situ capture of sulphur species through direct injection of the sorbent into the combustor, which is significantly enhanced through the recycling process, is also a significant advantage when compared to downstream abatement.
- Fuel, flexibility is possibly the main asset of ACFBC technology which is most suited for a broad variety of fuels, from coal washing residues, to high sulphur fuels such as petroleum residues including petroleum coke.
- ACFBC technology uses no coal mills (only simple crushers), which is a significant advantage over PC boilers, in particular when dealing with high ash content coals with high abrasivity.

FBC is commercially available as a stationary or a circulating version. The atmospheric “bubbling-bed” AFBC technology (BFBC) has a defined height of bed material and operates at or near atmospheric pressure in the furnace.

FBC can control gaseous emissions already during combustion by addition of limestone or dolomite (SO_2) and through low combustion temperatures and staged combustion (NOx.). FBC is a very suitable conversion technology for a large variety of biomasses and recovered fuels.

Advantages and disadvantages of Bubbling Fluidised Bed Combustion Technology BFB systems are generally cited as providing some of the following advantages over competing systems:

- Environmentally acceptable disposal of many industrial and agricultural wastes that could otherwise not be incinerated
- High availability is often claimed and many commercial units have operated well for lengthy periods.

- High combustion efficiency can often be achieved.
- Cost-effective operation is often cited - high availability coupled with high efficiency can result in the generation of additional energy from the same amount of fuel. In some situations, several fuels can be burned simultaneously.
- Fuel flexibility - a wide range of solid fuels has been utilised successfully in appropriately designed units.
- Combustion can be maintained in a stable condition even during fairly significant changes in fuel characteristics.
- Low operating costs - costs can be relatively low as there are no moving parts in the BFB boiler. In addition, refractories are usually very durable. The lack of in-bed heating surfaces in some designs eliminates many potential maintenance problems.
- Low emissions can be achieved – relatively low bed temperatures allow limestone to react effectively with sulphur species present. Low bed temperatures coupled with staged air minimise NOx formation.
- Suitable for retrofit applications - BFB units have often been used as replacements for old, inefficient alternatives such as grate-fired or small pf units.

Although BFBC units may have significant advantages over some competing forms of combustion technology, they may have a number of disadvantages when compared with PF fired plant. These include:

- To date, commercially proven only at relatively small scale. Range of units available presently limited to small-medium capacity.
- Slightly lower overall generating cycle efficiencies and higher greenhouse gas emissions
- Per unit of power produced compared to some pf-fired technology, unless the latter utilises FGD for sulphur control purposes.
- Relatively large volumes of solid residues can be generated. Some may require special measures for their disposal.

In the mid-1970s, the atmospheric “circulating” fluidised-bed combustion technology (CFBC) was developed. CFBC has particular advantages, e.g. with respect to heat transfer, combustion efficiency and fuel feed.

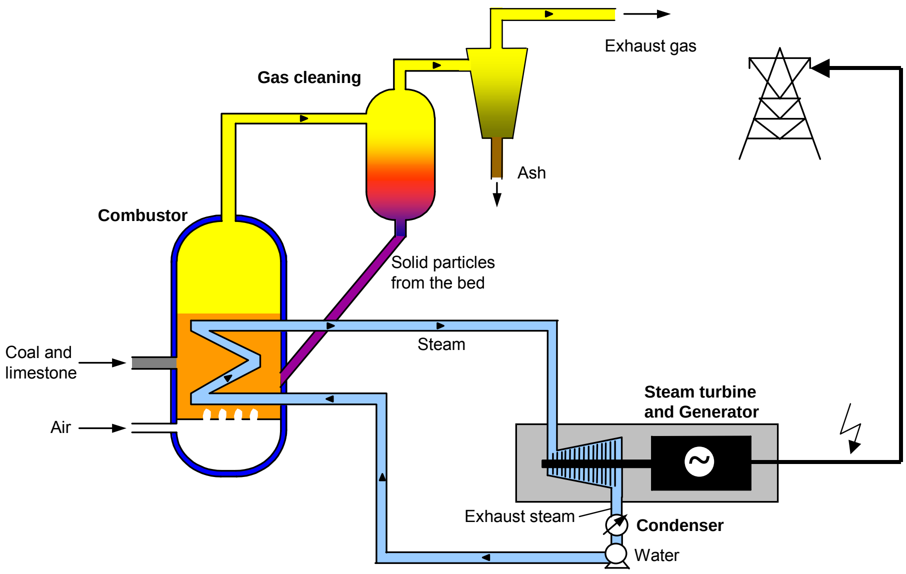


Figure 5: Schematic diagram for the CFBC technology

Advantages and disadvantages of CFBC The advantages over competing combustion systems generally cited by proponents of the various CFBC technologies include:

- Low levels of SO_2 and NOx can often be achieved without the addition of back-end cleanup systems.
- The capital costs of a CFBC unit can be ~10% lower than those associated with, for instance, a conventional pulverised fuel-fired system of the same capacity.
- Cooled combustion gases emerging from the CFBC can be cleaned of residual particles using conventional cleanup techniques such as bag filters or electrostatic precipitators.
- A CFBC is often capable of operating on a wide range of fuel types, including those that cannot be burned in more conventional systems. In effect, a fuel can be regarded as any material whose combustible content is capable of maintaining the bed temperature, thus increasing the range of fuel types significantly over earlier combustion systems.
- For a given output, an equivalent CFBC unit is often physically smaller than a pf-fired installation.
- The relatively long residence time of fuel particles in the system allows for the successful combustion of difficult-to-burn or light particles. In addition, it allows lengthy reaction times between limestone or dolomite and sulphur species present, thus reducing emission problems.

The disadvantages of CFBC technology are viewed as:

- Commercially proven only at relatively small scale compared to PF-fired systems. Although developments are in hand to scale up the technology, no demonstration/commercial plants are yet under construction.
- Thermal efficiencies are limited and comparable with those of PF-fired installations. Although supercritical steam conditions will increase efficiency, application is not yet widespread.
- Relatively large volumes of residues can sometimes be generated. Some of these residues can require special measures for their disposal. Utilisation of residues is limited and development of further options is required.

Table 3: European state-of-the-art AFBC power plants

Power Station	Fuel	Output net [MWe]	Steam pressure [bar]	Main steam temp. [°]	Reheat steam temp. [°]	Net efficiency LHV [%]	Year
Lagisza (PL) - planned	*coal*	*460*	*260*	*560*	*580*	*43*	*2007*
Gardanne Provence (F)	coal	250	169	567	567	40	1996
Sulcis (I)	coal	350	163	565	580	40	2005
Turow (PL)	lignite	216	132	540	540	38	1998

Following the introduction of the circulating technique (CFBC) characterised by the 250 MWe plant at Gardanne in France which was supported by the European Commissions THERMIE programme, the majority of FBC fluidised bed power plants are of the circulating type. Feasibility studies are under way for a plant of 600 MWe.

Figure 6: Gardanne CFBC power plant

The technique is offered world-wide by a number of companies.

3.4.4 Integrated Gasification Combined Cycle - IGCC

An alternative to coal combustion is coal gasification. When coal is brought into contact with steam and oxygen, thermo-chemical reactions produce a fuel gas, largely carbon monoxide and hydrogen, which when combusted can be used to power gas turbines. Integrated Coal Gasification Combined Cycle (IGCC) power generating systems are presently being developed and operated in Europe and the USA. These systems give increased efficiencies by using waste heat from the product gas to produce steam to drive a steam turbine, in addition to a gas turbine. Existing commercial systems achieve efficiencies close to 45%. With recent advances in gas turbine technologies these systems are capable of reaching above 50%. IGCC systems additionally produce less solid waste and lower emissions of SO_X, NO_X and CO_2. Over 99% of the sulphur present in the coal can be recovered for sale as chemically pure sulphur.

In a typical integrated gasification combined cycle (IGCC) power-generating plant, pulverised coal is fed into a gasifier at about 30 bar pressure, together with O_2 from an air separation unit (ASU). The raw fuel-gas is produced in the gasifier at about 1300ºC and is cooled to about 200ºC before being scrubbed with water to remove compounds such as NH_3 and hydrogen chloride (HCl). It is then further cooled and scrubbed with a solvent to remove sulphur compounds such as hydrogen sulphide (H_2S). The cleaned gas is then fired in a gas turbine. Ash in the coal is recovered as a mineral slag from the gasifier and the sulphur compounds removed from the gas are recovered as sulphur. N_2 from the ASU is typically added to the fuel-gas in the gas turbine to control NOx emissions.

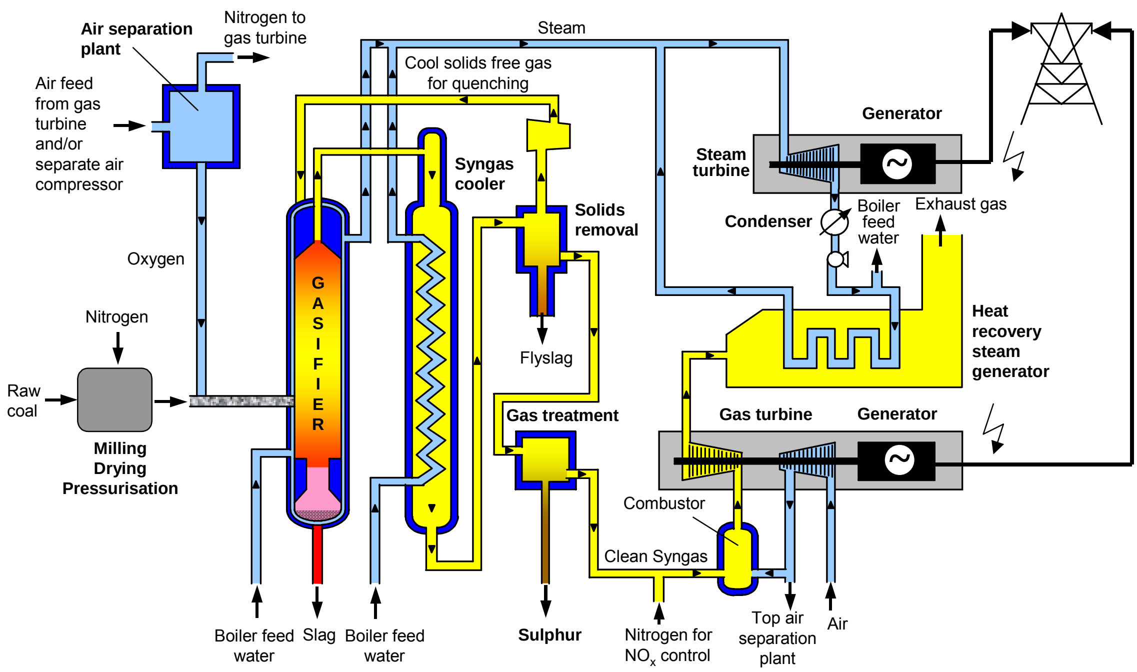


Figure 7: Schematic representation of a IGCC power plant

Further development work is required to overcome reliability and operational flexibility problems, and to reduce the cost. However, these obstacles to adoption are gradually being eroded. In the short-to-medium term, R&D effort is focusing on three major areas shown hereinafter:

- Enhanced understanding of gasification (to establish the fuel flexibility of IGCC technologies - directed at understanding gasification reaction rates and carbon conversion and predicting the gasifiability of individual coals and other fuels, ash/slag behaviour, and the potential for sulphur capture in fluidised bed gasifiers)

- Improved individual plant components (more reliable and/or cheaper gasifiers/syngas coolers, pressurised coal feeding systems, gas clean-up, gas turbines and ASUs)
- Improved overall process layout and design (specifically dynamic simulation, start-up and shut-down strategies, operability, simplified designs that reduce cost, and optimum integration strategies).

IGCC technology is based on a partial oxidation of coal aimed at producing a synthesis gas essentially made of hydrogen and carbon monoxide. This syngas is afterwards dedusted and desulphurised prior to be used to fuel a combined cycle.

The main advantages of IGCC are:

- an extensive desulphurisation through the use of efficient petrochemical processes,
- a high efficiency already reaching 45% and potentially above 50% in the future, due to the use of a combined cycle scheme, which helps reducing the greenhouse effect,
- low NOx emissions through NOx reduction systems equipping the gas turbine combustion chambers,
- vitrified ashes which are inert and thus preclude soil contamination,
- the capability to use high sulphur bearing fuels as well as industrial wastes and residues.

Disadvantages of IGCC are:

- High capital costs
- Complexity of installation

Table 4: European state-of-the-art IGCC power plants

Power Station	Fuel	Output net [MWe]	Gas turbine [MW]	Steam turbine [MW]	Net efficiency LHV [%]	Year
Buggenum (NL)	oil	250	155	128	41.0	1995
Puertollano (E)	coal	330	182.3	135.4	42.2	1997

The first IGCC plant was built in the early 1970s in Germany; however, large-scale demonstration units have only recently come into operation in Europe and the USA. These include Puertollano in Spain (330 MWe), Buggenum in the Netherlands (250 MWe) and Wabash River (260 MWe), Tampa Electric (260 MWe) and Piñon Pine (99 MWe) in the USA. These are achieving efficiencies of 38-44%.

Figure 8: Puertollano IGCC power plant

The Puertollano project involved the development of the world's largest Integrated Gasification Combined Cycle (IGCC), 330 MWe power plant. In 1992, the environmental advantages of this coal gasification technology gained the support of the European Commission under the THERMIE Programme, as a targeted project. In addition, 8 major European utilities and 3 technology suppliers formed a consortium named ELCOGAS to manage the project.

The plant was originally designed to run essentially on gas. However, following agreements reached with the Spanish Ministry of Industry and Energy, incentives were awarded to allow extensive modifications to be undertaken enabling low quality coal and coke to be used. The plant design ensured that its features were focused on two main targets: improved efficiency of 45% net and reduced emissions. Emission data for the year 2000 showed the plant's emission levels were well below the regulatory limits specified when gas was being used.

The Gasification Unit is based on the PRENFLO system, an entrained-flow system with dry feeding. The syngas is produced by reaction of coal with oxygen at high temperatures up to 1600ºC. The PRENFLO process is capable of gasifying a wide variety of fuel types, and qualities of coal, for the production of synthetic gas. The "design" fuel of Puertollano power plant is a 50% mixture, by weight, of local high ash coal and high sulphur petroleum coke. The gasification process takes place in a cooled gasifier vessel, the internal surface of the wall being lined with refractory to protect the metal vessel from the hot coal gas. The slag produced during gasification provides a critical protective layer, which prevents diffusion of the gas through the refractory coating. The slag flows down the gasifier walls to be quenched and granulated before removal. The hot coal gas exits the top of the gasifier, where it is quenched to ~800°C with cooled recirculated gas. The quenched gas then enters the high-pressure steam heat exchanger, located in the same pressure vessel as the gasifier and the quenching zone, and then to an intermediate pressure exchanger located in a separate vessel.

The Gas Cleaning Unit treats the gas at the outlet of the intermediate pressure boiler removing the solid particles (using candle filters), and incorporates a water wash step (Venturi scrubber) for ammonia, HCl, HCN and trace component removal. The sulphur removal unit consists of a fixed bed catalyst (99.9% efficiency). The cleaned gas is then passed through a conditioning phase (saturation with water), before delivery to the gas turbine.

The Air Separation Unit supplied by Air Liquid, uses air extracted as a bleed from the gas turbine air compressor, to generate oxygen with high purity (85%) for feeding to the gasifier and nitrogen for pneumatic transportation of the fuel. Nitrogen is also used as a safety purge system.

The Combined Cycle Plant is designed around a Siemens V94.3 gas turbine, a triple pressure heat recovery boiler supplied by Babcocks Wilcox Espanola and a Siemens reheat generator. This equipment produces steam that is used to produce additional electric power in a conventional steam turbine with condensation cycle. The gas turbine is able to operate with both syngas and natural gas allowing greater plant flexibility.

3.4.5 Solid Fuel Processing

The traditional role of coal preparation has been one of improving the quality of coal to meet market requirements, e.g. by reducing ash content and providing correctly graded coal. However, more recently, it has been widely recognised that coal preparation can also bring considerable environmental benefits. These benefits include reduced emissions of heavy metals, sulphur dioxide, through removal of some pyritic sulphur from coal, and reduced emissions of carbon dioxide, through increased efficiency of downstream coal utilisation plant. Other benefits include the reduced transportation requirements, including energy savings, associated with low-grade coal and reduced quantities of ash residues for disposal.

With these benefits, coal preparation has now emerged as an important clean coal technology, particularly in developing coal economies, such as CIS, where much of the coal is still utilised in its raw untreated state. In these countries, there is a growing awareness of the benefits of improved quality and consistency of coal supply and one of the immediate priorities is to increase the level of coal preparation. Furthermore, with global coal consumption predicted to increase in the future, largely to meet the needs of these developing economies, there will be a need for coal preparation technologies for many years to come.

Table 5: Summary of the EU Coal Preparation Technologies

Process	Technologies
Raw coal pre-treatment	• Static screens • Vibrating screens • Jaw crushers • Twin-scroll sizers
Coal cleaning	Coarser grades (above 3 mm) • Dense medium static baths • Dense medium cyclones (normally down to 0.5 mm) • Jig washers, e.g. Baum jig, Batac jig, ROM jig
	Finer grades (below 3 mm) • Fine coal density separation techniques (e.g. spiral concentrators and teeter-bed separators) • Froth flotation, column and mechanical
	Ultrafine grades (below 0.3 mm) • Froth flotation, column and mechanical • Enhanced density separators
Coal sizing and classification	• Static screens, e.g. sieve bends • Vibrating screens, e.g. product grading screens, desliming screens, Banana screens • hydro cyclones
Dewatering	Grades above 5mm • Dewatering screens • Vibrating-basket centrifuges and scroll centrifuges
	• Grades below 5mm • Vacuum filters (disc, drum or horizontal belt) • Hyperbaric filters, pressure filters • High speed scroll centrifuges
Tailing treatment and water clarification	• Thickener/classifiers, enhanced by the use of chemical reagent systems • Filter presses • Multi-roll filters • Solid bowl centrifuges
Plant monitoring and control	• Process monitors, e.g. nucleonic density gauges, magnetic flow-meters, ultrasonic level detectors and mechanical belt weighters • Coal quality monitors, e.g. on-line ash and moisture monitors • Automatic control systems • Management information systems • Intelligent control systems, e.g. neural networks

3.4.6 Flue Gas Cleaning

Flue gas treatment can achieve virtually any level of emissions clean up. However, retrofitting these technologies often has considerable practical and economic implications. Installing FGD and NOx control will typically add 25% to the cost of new PF plant and can represent about 30% of plant capital costs when retrofitted to existing plant. It also increases annual operating costs by 5-10% and reduces plant efficiency by around 2%.

<u>NOx</u>

A number of processes have been developed for removing NOx from flue gases. These processes fall into one of three categories:

- selective catalytic reduction (SCR)
- selective non-catalytic reduction (SNCR)

- combined processes for SO_2 and NOx (SNOx) removal.

SCR methods, which involve the injection of NH_3 in the presence of a catalyst, can reduce 80-90% of NOx to molecular nitrogen (N_2) and water vapour. SCR is selective in that it does not oxidise NH_3 or SO_2. It is expensive to install and operate, however, as catalysts have limited lifetimes. Non-catalytic methods, which involve the injection of urea or NH_3 directly into the furnace, are also available. The NOx –reduction rates are somewhat lower, typically 40-50%.

SO_2

SO_2 is emitted from coal combustion through oxidation of the sulphur in the coal. The coal itself can be treated before combustion (i.e. via coal preparation) to reduce its sulphur content, but FGD is used to remove SO_2 after combustion. Two main FGD options are available, each capable of removing >95% of SO_2 :

- regenerative (eg the Wellman-Lord process)
- non-regenerative (wet scrubbing and sorbent injection).

Although both use a sorbent, eg lime or limestone, regenerative processes use the sorbent as a carrier for the SO_2 and can be regenerated for further use; by-products are elemental sulphur or a concentrated SO_2 stream useful for sulphuric acid manufacture. Few commercial plants are available because they are more complex and costly to install. In non-regenerative methods, the SO_2 combines permanently with the sorbent to form a new compound. The majority of FGD plants installed on coal-fired plants are of this type, of which wet scrubbing is the most common. The sorbent is usually mixed with water before being brought into contact with the flue gas. The residue, a wet mixture of calcium sulphite and calcium sulphate, if dried and completely oxidised, forms gypsum that is used extensively in the building industry.

Spray-dry systems have been developed as an alternative to wet FGD. Sorbent is injected directly into the flue gas (alone or in combination with in-furnace desulphurisation). These are less costly to install but have higher operating costs and are, therefore, better suited to smaller plants or plants with lower load factors. Like wet scrubbers, the waste product (sodium or calcium sulphate) is mixed with the fly ash.

SNOx

Combined processes for removing NOx and SO_2 from flue gases are just now achieving commercialisation. Processes capable of removing both gases include the use of activated carbon reactor beds, microbial removal and electron beam irradiation. All these systems tend to be complex and are currently expensive. A 300 MW full-scale SNOx plant began operation in Denmark (Ålborg Power Station) in 1991. A 5 MW pilot plant also exists for a combined particulate, SO_2 and NOx removal system. Development of these systems may be encouraged by their potential for producing refinery products like sulphur or sulphuric acid.

Particulates

The two main technologies used to control particulate emissions from large-scale coal-burning plant are electrostatic precipitators (ESPs) and fabric filters or “baghouses”. ESPs are most commonly chosen for large boilers. In these, the dust-laden flue gases are passed horizontally between collecting plates, where an electrical field creates a charge on the dust particles. The particles are drawn towards the collecting plates, where they accumulate. They are dislodged periodically by vibrating the plates and fall into a hopper for removal. ESPs are capable of removing >99.5% of particulates and meeting all current emission standards for particulates.

ESPs are generally not effective with coals containing <1% sulphur. However, there are a number of technologies available that can improve their efficiency. Sulphur trioxide (SO_3) injection can be used to condition the fly ash particulates to improve their resistivity; precharging can be used to improve removal; and ESP controllers can be upgraded to digital processes that employ pulse energisation. Fabric filters can remove up to 99.9% of particulates and are the main alternative to ESPs. They are less sensitive to dust loading or ash characteristics than ESPs and are, therefore, more flexible. However, they are also more expensive to construct and operate. A baghouse consists of a large surface area of porous fabric that filters out particulates. Dust builds up on the surface of the fabric and this in turn assists the collection process. The bag is cleaned intermittently by reverse-pulsing air through the filter. This dislodges the dust and allows it to fall into a hopper. Much research has been conducted into fibre materials used to make the bags, and organic coatings to improve temperature stability and resistance to chemical and mechanical attack. Modern materials also allow for the development of more robust ceramic fabric filters, metallic fabrics and rigid filters that can be used in higher-temperature flue gases.

Table 6: Best effective emission values for the main pollutants in coal fired power stations world-wide.

Power Station	Fuel	MWe [MWe]	NOx [mg/Nm³]	SO_2 [mg/Nm³]	Particulates [mg/Nm³]	Year
Mellach (A)	Coal (< 1% S)	250 + heat	180	110	10	1986
Hawthorne (USA)	Coal (< 1% S)	550	65	150	22	2001
Boxberg (D)	Lignite	907	150	350	10	2002
Haramachi (J)	Coal (< 1% S)	2x1000	120	200	25	1997
Tomatoh-Atsuma (J)	Coal (< 1% S)	2x700	100	143	10	2000
Tachibana-Wan (J)	Coal (< 1% S)	2x1050	90	143	10	2002
Hekinan (J)	Coal (< 1% S)	2x1000	30	75	5	2001
New Units (Japan)	Coal (< 1% S)	700÷1000	50	75	5	

3.4.7 CO_2 removal and storage

Many systems for controlling the pollutants are already in widespread use in different parts of the world. In parallel with the on-going drive for greater efficiency and lower costs for such control systems, however, efforts are also being focused increasingly on the control and minimisation of CO_2 emitted from coal-fired power plants and other large industrial processes. Several possible routes exist towards this objective. The options available to reduce the CO_2 emissions from fossil fuelled plants are:

- To increase the power plant efficiency.
- Change to another fuel with less carbon dioxide, or to biofuels which is renewable.
- Capture and permanent storage of CO_2.

<u>Improved plant efficiency.</u>

Increased plant efficiency means that less coal is burned (producing less CO_2) for the same power output. This may be achieved through more advanced development of existing (PF) plant, for instance, by applying enhanced steam conditions. At present, the average thermal efficiency of PF plant in OECD countries is roughly 36% (Lower Heating Value). However, in many parts of the developing world, efficiencies are much lower. Clearly, a significant reduction in the amount of CO_2 emitted could be achieved by bringing such plant up to a higher standard. The latest developments in PF technology have pushed efficiency levels to above 40%, which means a drop in the level of CO_2 emitted of up to 25%. The renewal of the power plants in the new countries in Germany of reduced the CO_2 emissions by 40% adjusted for the same level of energy production.

CO_2-neutral fuels

The CO_2 issue can be further addressed by the introduction of so-called "CO_2-neutral fuels" such as biomass and wastes with a sufficiently high calorific value (see also next chapter). Such fuels and their utilisation as part-replacement in coal fired plants have been under investigation for several years, particularly in the EU, where these fuels are fired directly or as their pyrolysis products. However, experience so far revealed that, apart from their relatively small contribution to the total energy supply and their limitations in temporal and spatial availability, considerable fuel dependent operating problems may also arise. Because of the general strategy to widen the range and increase the utilisation of such fuels, further intensive research is required into their specific properties and their interaction within the combustion process and with the surrounding materials.

However, with the incorporation of CO_2 capture, efficiencies of both systems will initially be reduced substantially, by around 10-12 percentage points for PF, less for IGCC, at around 6-8 percentage points.

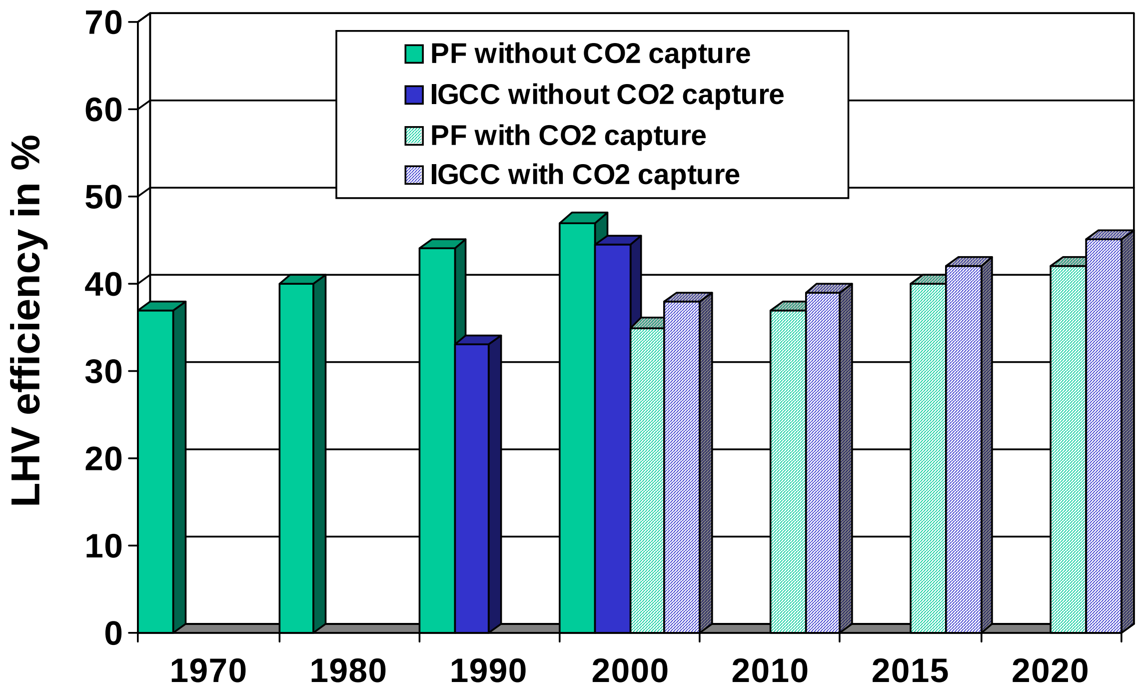


Figure 9. Efficiencies over time for PF and IGCC with CO_2 capture penalty in years ahead.
(John Topper: *Clean Coal Technology and CO_2 Mitigation*

CO_2 capture.

Reasonably matured technologies for capture of CO_2 are usually divided in three categories

- Post-combustion capture, where the flue gas from the combustion is cleaned from CO_2.
- Pre combustion capture, where the carbon is removed from the fuel before the combustion.
- Utilisation of oxygen for the combustion, but without the nitrogen in air, in form of either air separation or a solid oxygen carrier

The main approach to controlling CO_2 emissions is to capture it from the combustion flue gases. Some types of CO_2 capture technologies (based on both chemical and physical absorption) are well established and have been in use for several decades. The majority of chemical-based methods rely on scrubbing systems that utilise amine solutions to remove CO_2 from exhaust gases. Amine scrubbers have already been applied to different types of coal-fired industrial process and power station. In most cases, the systems used are similar in concept and configuration and usually employ a regenerative amine, such as monoethanolamine (MEA) as the working solvent. Depending on the particular application and type of flue gas being treated, such systems can recover up to 98% of the CO_2 present, and produce a CO_2 stream of up to 99% purity. Historically, many processes have relied on MEA. Recently, however, more advanced amines have been developed, for instance by Mitsubishi Heavy Industries (MHI), and are now being applied commercially. Such new amines are claimed to suffer less degradation and to have lower consumption rates and energy requirements than conventional MEA-based solvents; significant improvements in performance have been reported. Here, technological developments have been instrumental in both improving product quality and reducing operational costs.

A number of commercial-scale physical absorption-based technologies are also in use, generally applied to systems operating at higher pressures. These rely on a range of solvents that include methanol and propylene carbonate. For IGCC applications, processes based on the use of proprietary solvents such as Union Carbide’s Selexol are considered to be the most applicable. Such solvents are favoured where high concentrations of CO_2 are present in the flue gas stream. They also impose low energy requirements on the system. In the United States, Selexol-based systems have been demonstrated at the Texaco Cool Water IGCC plant and used commercially at the Destec-based Plaquemine facility. In general, further development of physical solvent-based systems would be advantageous in order to broaden their range of operating conditions.

Storage & sequestration of CO_2

Although the emphasis to date has focused on CO_2 abatement, attention is now being given to the technical and economic prospects for recovering CO_2 for subsequent use or disposal. Injecting carbon dioxide into deep, unmineable coal seams where it is adsorbed to displace methane (effectively: natural gas) is another potential use. Currently the economics of enhanced coal bed methane extraction are not as favourable as enhanced oil recovery, but the potential is large.

The world's first industrial-scale CO_2 storage was at Norway's Sliepner gas field in the North Sea, where nearly one million tons per year is injected into a deep reservoir (saline aquifer) and remains safely in place. The US$ 80 million incremental cost of the sequestration project was paid back in 18 months on the basis of carbon dioxide tax savings at $50/ton. (The gas contains 9% CO_2 which must be reduced for export.) The overall Utsira sandstone formation there, about one kilometre below the sea bed, is said to be capable of storing 600 billion tons of CO_2.

While the scale of envisaged need for CO_2 disposal far exceeds today's uses, they do demonstrate the practicality. Safety and permanence of disposition are key considerations in sequestration. Different sources estimate that if CO_2 capture and storage is developed to avoidance costs of about 20 €/ton of CO_2, the technology can be commercially introduced.

Captured carbon dioxide gas can be put to good use, even on a commercial basis, for enhanced oil recovery. This is well demonstrated in West Texas, and today over 3000 km of pipelines connect oilfields to a number of carbon dioxide sources in the region. At the Great Plains Synfuels Plant, some 13,000 tons per day of carbon dioxide gas is captured and 5000 t of this is piped 320 km into Canada for enhanced oil recovery. This Weyburn oilfield sequesters about 85 cubic metres of carbon dioxide per barrel of oil produced, a total of 19 million tons over the project's 20 year life. Overall in USA, 32 million tons of CO_2 is used annually for enhanced oil recovery, 10% of this from anthropogenic sources.

3.4.8 Co-combustion of biomass

Interest in co-combustion of coal with biomass and waste fuels is growing rapidly world-wide with a view to achieving sustainable development, social cohesion, energy supply security and industrial competitiveness.

Co-combustion of coal with biomass or waste fuels offers many advantages over using the fuels separately. From the waste / biomass perspective, co-firing with coal offers the opportunity to use larger-scale higher-efficiency plants. Using coal as part of a fuel mix allows operators to be able to compensate for variations in the fuel mix and stabilise combustion. From a coal perspective, the use of biomass or wastes offers the potential to use cheaper fuels. There are also potential global and local environmental benefits if coal is replaced partially with biomass fuels, which do not release fossil-derived CO_2 or other pollutants such as SO_2.

Co-firing of biomass in existing fossil-fuel fired power plants can reduce high costs and efficiency disadvantages of existing biomass energy generation. Reasons are the lower capital and operating costs, higher electrical efficiencies and increased fuel flexibility and the avoidance of additional generation capacity. Another driving force of gaining importance is the ban to dump combustible wastes.

Co-firing refers in practice of introducing biomass as a supplementary energy source in high efficiency boilers. The technique of co-firing has been practiced, tested or evaluated for a variety of biomass types and co-firing shares in combination with different combustion technologies and processes, including grate firing, fluidised bed combustion and pulverised combustion.

In most of the co-combustion installations currently in operation, biomass is directly combusted together with fossil fuels, mostly coal. In the pulverised coal fired installations such as operating in central Europe, the percentage of biomass that is co-fired is relatively small as compared to the fluid bed installations operating in Scandinavia.

Co-combustion is practised with different types and amounts of biomass wastes in different combustion and gasification technologies, configurations and plant sizes. One can distinguish:

- direct co-combustion
- indirect co-combustion
- parallel firing.

For direct co-combustion, all components of the secondary fuel enter the boiler together with the primary fuel since both fuels enter the boiler (eventually in a separate feeder). Currently, this is the most commonly applied co-combustion principle. The cheapest variant of direct co-combustion in a pulverised coal power plant is through mixing pre-treated biomass and coal in the coal yard or on the coal conveyor belt, before combustion in the same boiler. Many coal- and oil-fired boilers at power stations have been retrofitted to permit multi-fuel flexibility. At the Gelderland power plant for example (NL), waste wood is pulverised and directly co-fired in the pulverised coal furnace using a separate burner. Another option is to install a biomass grate in an existing pulverised coal burner as has been done in the St. Andrä power plant in Austria. Sludge-types of biomass can be directly co-fired using an oil lance.

Indirect co-combustion by pre-gasification is applied in a number of plants in Austria (Zeltweg), Finland (Lahti) and the Netherlands (Geertruidenberg). The investment costs are significantly higher as compared to a direct co-combustion installation. One of the major advantages is that ashes of the main fuel and the co-combusted fuel are kept separate.

For parallel firing, a fully separate combustion installation is used for the biomass/waste and the steam produced is fed to the main installation where it is upgraded to higher conditions, resulting in higher conversion efficiencies. Though the investment in indirect co-firing and parallel firing installations is significantly higher than in direct co-combustion installations, advantages such as the possibility to use relatively difficult fuels with high alkali and chlorine contents and the separation of the ashes are reasons why this can be justifiable. An example of parallel firing is the supply of steam from the MSWI in Moerdijk (Netherlands) to a neighbouring gas fired combined cycle power plant.^

3.4.9 Capital costs of coal power plants

According to IEA estimation the investment in a new generating capacity for all types of energy generation is expected to be of the order of 4 trillion US$ in the period to 2030, The figure is based on following capital costs relating to thermal power plants.

Table 7: Capital costs estimates

Technology	Capital costs in US$ per kW
Conventional coal power plant	800 – 1,300
Advanced coal power plant	1,100 – 1,300
Circulating Fluidised Bed combustion plant	1,100*
IGCC	1,300 – 1,600

** - POWERCLEAN estimation*

3.5 Refurbishment and upgrading of existing power coal power plants

Construction of power plants was at its highest in the years between 1960 and 1990. In the last decade, coal-fired power plant construction has declined while more natural gas combined cycle plants are being built. This trend is expected to continue especially with deregulation. As plants age they tend to become less reliable. Their performance and efficiency decline, and operating and maintenance costs increase. Derating of the plant due to equipment ageing and changes in operating regimes may also have occurred.

There are generally two methods of power plants modernisation:

- refurbishment and
- upgrading.

The cost-effectiveness of refurbishment was a subject of many studies. The review of those can be concluded as follows;

- Economic modelling of the refurbishment project compared with the construction of a new fossil plant shows a wide range of outcomes depending on the assumptions.
- Refurbishment has no clear economic advantage over the construction of a new fossil plant of equivalent capacity.

IEA has carried out a study with power plant refurbishment of existing plants is based on the assumption that major refurbishment will take place once during the lifetime of a plant during the next thirty years. Only plants that will not be retired during this period are considered. The cost assumptions used in this calculations in case of developed countries amounts to 200-300 $/kW for boilers and 100 for turbines and in case of economies in transition amounts for to 150-300 $/kW for boilers and 50-100$/kW for turbines.

The power plants may be burning coals for which they were not originally designed, further affecting their performance. Current environmental legislation is usually stricter than in the past; consequently older power plants may not meet the new environmental requirements.

Upgrading of existing power plants comprised of:

- retrofit of pollution abatement and control technologies using electrostatic precipitators or flue gas desulphurisation and process optimisation by installing modern instrumentation and control systems to improve plant performance and reduce operating and maintenance costs.
- repowering existing power plants with circulating fluidised bed (CFB) boilers or by integrating a gas turbine to form a combined cycle.
- Rehabilitation/reconstruction of entire units, of mills and pulverisers and the transport of the pulverised coal to the burners.

Retrofitting is the primary concept in any modernisation scenario. Retrofitting ageing power plants with pollution control equipment or repowering with fluidised bed boilers or gas turbines can be in contrast to refurbishment more cost-effective than building new power plants. The evaluation of any plant for upgrading/retrofitting/repowering includes a wide range of business aspects such as load growth forecasts, financial parameters, environmental regulations and other legal requirements. For example, two reasons for upgrading older plants are to replace lost capacity and to help meet future changes in power demand. Many of these older plants were built on the assumption that they would be used at a constant high loading (base-loaded). However, the upgraded plant may be obliged to vary output to match demand (load following). Fuel represents about 60-80% of a power plant’s operating costs; consequently significant savings can be made by firing cheaper fuels. The requirements and technical condition of each power plant are bound to be different. Thus the suitability of a power plant for rehabilitation/retrofitting/repowering has to be determined separately for each plant. Continuous monitoring is required following the upgrade to confirm that the anticipated improvements have been achieved. Some factors need to be considered when evaluating a refurbishment project.

The most important retrofitting activities are:

- Improvement of the fuel preparation and firing system towards the increase of the burnout, the uniformity of the flue gas temperature distribution and the abatement of the air pollutants
- Implementation of techniques for further reduction of the NOx emissions and for the flue gas desulphurisation
- Improvement of particles precipitation systems
- Optimisation of the existing fuel drying system or implementation of new effective drying techniques
- Replacement, rearrangement or size change of heat exchange surfaces
- Optimisation of the heat exchanger maintenance and the soot blowers operation
- Supplementary heat exchange surfaces for further exploitation of the flue gas thermal energy
- Reduction of the boiler infiltrate air by improving the boiler sealing
- Improvement of the air preheating system
- Reduction of the ID and FD fan losses
- Improvement of the cooling tower performance
- Cold end optimisation (condenser and low pressure section of steam turbine)
- Steam turbine retrofitting (blades replacement and improvement of the labyrinths' operation and turbine control system, etc)

The effect of deregulation/liberalisation on the retrofit and/or rehabilitation of coal-fired power plants will be an increase in competition emphasising the role of the most cost-effective generation methods and locations. However, investment in retrofit or rehabilitation will be deferred until the complete development of this deregulated market. Competition and financial issues may have the initial effect of a drive to generate power at minimum cost. Upgrading or repowering may have to wait until costs are reduced even further or environmentally driven licence fees are used. Once a market is deregulated, greater demand for retrofit or rehabilitation is expected to materialise in the short-to-medium term depending on the potential and the prospects of a plant to produce power cost-effectively. Deregulation can provide an economic environment which may stimulate market-driven retrofit and rehabilitation projects in the long term.

Further developments in improving thermal efficiencies, minimising environmental impact while enhancing fuel flexibility and reducing capital and operating costs, may open up more opportunities for repowering with CFB boilers. Opportunities may be further enhanced by the development of new markets for the use of CFBC residues. New designs, especially more compact boilers, may facilitate the repowering of ageing boilers. The survey results demonstrate that compliance with environmental regulation is the driving force for retrofit of air pollution abatement and control systems, and market competition is the main driving force for repowering. The most important factor is the competitive lifetime of the modified plant. The likely competitive period income needs to be significantly greater than the project costs. Legislation on reducing greenhouse gases would increase the potential for repowering with gas turbines.

Another important upgrading factor is renovating equipment to increase fuel flexibility which allows the operator to take advantage of cheaper coals on the spot market. Coal blending is receiving increasing attention from power generation companies worldwide. It is used to produce coal of the correct quality for the intended use at the lowest price. Cheap coals can be blended with low-sulphur coals, for example, to produce a mix that meets the relevant legislation at the lowest price.

Coal blending is used routinely in countries depending heavily on imported coal such as Japan, Denmark and the Netherlands. Improved performance is being gained from more appropriate coal selection/blending, handling and grinding, improved pf flow distribution and metering, and accurate monitoring and 'intelligent' control of other plant parameters. Improved instrumentation and data analysis/interpretation is also enabling operating costs to be lowered by more effective and timely maintenance that improves plant reliability and availability, reduces overall maintenance costs and extends plant life.

Instrumentation has been developed and is now being applied to monitor on-line parameters such as coalapplicability, bunker flows, milling performance, distribution of pf to burners and unburnt carbon in ash. Data generated in this way are being analysed and interpreted by 'expert' systems, and used for control purposes allowing a NOx emissions reduction by up to 25%. A significant reduction of NOx generated by the combustion process can be achieved through modifications either to the burner or to the furnace. During coal combustion, NOx can be formed either from nitrogen in the combustion air or from that within the coal itself; how much depends on the availability of O_2, the air temperature, the temperature-time history experienced by coal particles, and coal properties such as volatile matter content and reactivity. Combustion modifications hence aim to reduce both the supply of O_2 and the local temperatures in the furnace. Some relevant parameters (e.g. furnace volume) are difficult to change; however, significant NOx reduction can be achieved by fine tuning, improved control systems and balancing fuel/air ratios.

Low-NOx burners are designed to control the initial mixing of air and fuel, to maintain the temperature and O_2 levels in critical parts of the flame at the minima necessary for effective combustion. They are now widely installed and can reduce NO emissions by 50-70%. Air staging aims to reduce the level of O_2 in zones where it is critical for NOx formation. It can be applied in the furnace or in the burner and 20-40% NOx reduction has been achieved on full-scale plant. Through the combination of Low-NOx burners with furnace air-staging 50-80% NOx reduction can be achieved. Fuel staging i.e. reburning aims to reduce the NOx already formed. The technique involves injecting fuel into a second combustion zone generally above the main combustion zone. The reburning allows a NOx emissions reduction by 50-60%.

The amount and nature of unburned carbon in the ash is thought to affect the performance of electrostatic precipitators, which are commonly used to remove fly-ash from power-station flue gases. Many coal-fired boilers retrofitted with low NOx firing systems are experiencing significant operational difficulties due to increased carbon in the fly ash or increased water wall wastage. Although the magnitude of an increase in unburned carbon after a low NOx retrofit is system and coal dependent, it is often the case that a reduction in emissions of nitrogen oxides is accompanied by a corresponding increase in the amount of unburned carbon in fly ash. Specific conclusions regarding the magnitude of carbon in ash include:

- The effect of improving coal grind is highly dependent upon the configuration of a given boiler and may be less important for units that have undergone low-NOx retrofit.
- Changes in air distribution after a low NOx retrofit can have a substantial effect on carbon levels in fly-ash.
- Furnace geometry, such as wingwall location and mills in service, can dramatically impact carbon levels in fly-ash.

4 Costs of electricity generation

Chapter Key Topics:

- For small-to medium-power outputs (up to approximately 30 MW), a diesel generator power plant can be a genuine alternative. The high efficiency of modern diesel engines is slightly less than combined-cycle with the same rating.
- Whenever gas or oil is fired in a power station, the combined-cycle plant is more economical than the steam power plant due to its higher efficiency and lower specific price. Modern combined-cycle plants are simpler, less expensive, and operationally more flexible than steam power plants.
- For short utilization periods (peaking units), the gas turbine is most economical. Gas turbines can serve as intermediate - or base-load units in countries where fuel is abundant at low cost. The lack of water consumption has made this machine popular in dry regions. The short installation time allows a customer to plan a new installation on short notice.
- If all fuels are readily available at world market prices, gas fired combined-cycle plants are the most economical solution for intermediate- and base-load applications. This results in a limited environmental impact (small heat rejection or low water consumption). With clean fuels like natural gas, this technology also achieves lowest emissions.

4.1 Cost of electricity

The cost of electricity is a specific term related to MWh of electricity produced. It consists mainly of capital cost, fuel cost, and operation and maintenance costs. In the current trend towards deregulation of the power generation industry the cost of the generated electricity is a key element when selecting the type of power plant for a given application. Other factors that are evaluated include:

- permitting procedure
- financiability, loan structures
- environmental concerns (nuclear waste, air emissions, water consumption, heat rejection, noise)
- construction time, depreciation period of the project, etc

Every power plant is designed to keep the production cost as low as possible. Legislation and environmental protection give boundary conditions to this goal.

It should be noted that the presented information can vary depending on local and regional conditions, and therefore represents general trends (e.g. fuel gas prices can be regionally below half of world market prices making plants using fuel gas even more competitive).

Capital costs per unit of electricity for a given power plant depend on the price and the amortization rate for that plant, on interest or on the desired yield on capital investments (annuity factor), and on the load factor of the plant. Capital costs are also influenced by the interest during construction.

Fuel costs per unit of electricity are proportional to the specific price of the fuel and inversely proportional to the average electrical efficiency of the installation (this average electrical efficiency must not be mixed up with electrical efficiency at rated load).

Operation and maintenance costs consist of fixed costs of operation, maintenance and administration (staff, insurance, etc.) and the variable costs of operation and maintenance, and repair (consumables, spare parts, etc.).

By adding the capital cost, fuel cost and operation and maintenance cost the cost of electricity is calculated. Present value is generally the basis used for economic comparisons. The various costs for a power station are incurred at different times but for financial calculations are corrected to a single reference time, which is generally the date on which commercial operation starts. These converted amounts are referred to as present value.

The equivalent utilization time at rated output is the electrical energy generated by a plant in a period of time divided by the rated output. This definition enables corrections to be made for the effects of different operating modes (e.g. part-load operation) for the power plants under consideration in an electrical grid, so that they can be analyzed on a comparable basis.

It is important to understand that the cost of electricity is made up of fixed and variable costs.

Fixed costs are:

- interest and depreciation on capital
- the fixed costs of operation, maintenance and administration (e.g. staff)

Variable costs are:

- the fuel used
- the variable costs of operation, maintenance and repair (e.g. spare parts)

For a time of low demand and high supply (e.g. night hours), power stations can quote a price as low as the variable costs and, for short periods of time, an even lower figure, since stopping a station also incurs costs. During times of high demand (e.g. noon peak) they can quote at a level which will recuperate additional fixed costs. For reasons of simplicity, the average cost of electricity will be used for the following comparisons.

4.2 Competitive standing of combined-cycle power plants

On the following sections, the combined-cycle power plant is compared with other thermal plants.

The main range of ratings under consideration is between 30 and 1000 MW. Combined-cycles with a smaller output can, of course, be built but they are less interesting for pure power generation, because the relative cost increases as the power rating decreases. These are optimally used for heat and power production (e.g. district heating or process-steam delivery at the same time as power generation).

4.2.1 Comparison of turnkey prices

The figure below shows how specific investment costs for the various types of power plants depend on the power output. These costs are valid for turnkey installations. They are based on 1998 price levels and progress payments and do not include interest during construction. The data shown indicates trends, so appropriate caution must be taken in applying them, since many factors affect the price of a power plant-site-related factors such as soil conditions; earthquake factors;

noise limits; types of cooling and corresponding structures; emission limits; labour rates; commercial risks; legal regulations, and so forth. The figure also shows the low investment costs required for the gas turbine, which have contributed significantly to its wide spread acceptance.

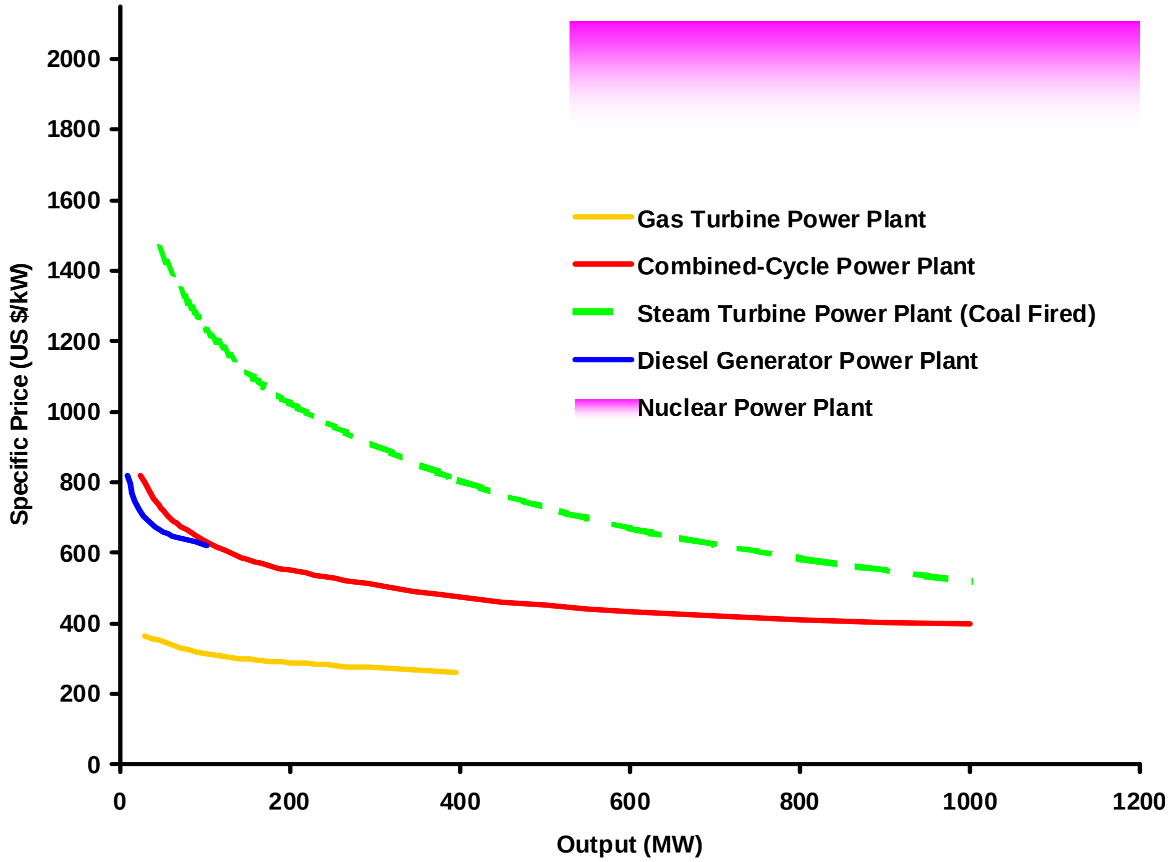


Figure: Comparison of different turnkey power plants in terms of specific price and output

Taken together with its simplicity and short start-up time to full load, the gas turbine is an attractive peak-load machine. Steam power plants are more expensive than combined-cycle power plants. Combined-cycle plants are quite inexpensive and therefore easier to finance compared to conventional power stations.

The following figure shows the breakdown of the total cost in a combined-cycle plant between the main equipment.

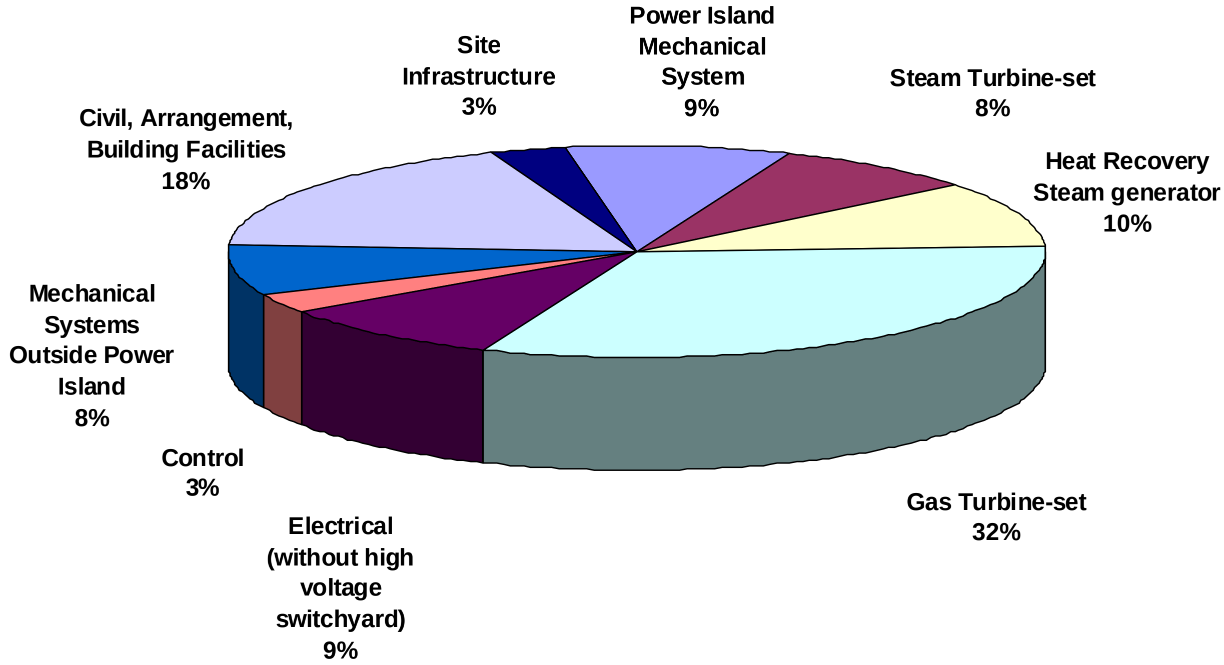


Figure: The cost percentage of the different plant areas for a typical 400 MW turnkey combined cycle plant

4.2.2 Comparison of efficiency and fuel costs

At today's fuel prices, efficiency is an important factor for installations operated at intermediate or base load. If an expensive fuel like liquefied natural gas (LNG) is used, the efficiency is crucial. For that reason high efficiency is a prerequisite for having an economical plant.

The figure below indicates how electrical efficiency at rated load for the different types of power plant relates to the power output. Steam turbine power plants have been segregated into coal fired and nuclear plants. The combined-cycle plants are without supplementary firing. The chart points out the thermodynamic superiority of the combined-cycle plant. This was made possible, to a large extent, by gas turbine technology which already achieves an efficiency of 38% to 40% with a turbine inlet temperature of 1300°C. Only a few years ago, the efficiency of a newly installed coal-fired steam power plant was at these levels-but with much a higher investment cost and complexity.

Some gas turbines can burn heavy oil or crude oil. Gas turbines with large combustion chambers and single burners are better capable of burning heavy fuels than those with several burners/combustion chambers since the latter are more sensitive to changes in flame length, radiation, etc. Modern gas turbines with high firing temperatures are, in general, not designed for heavy fuel operation, but mainly for natural gas and distillate oil.

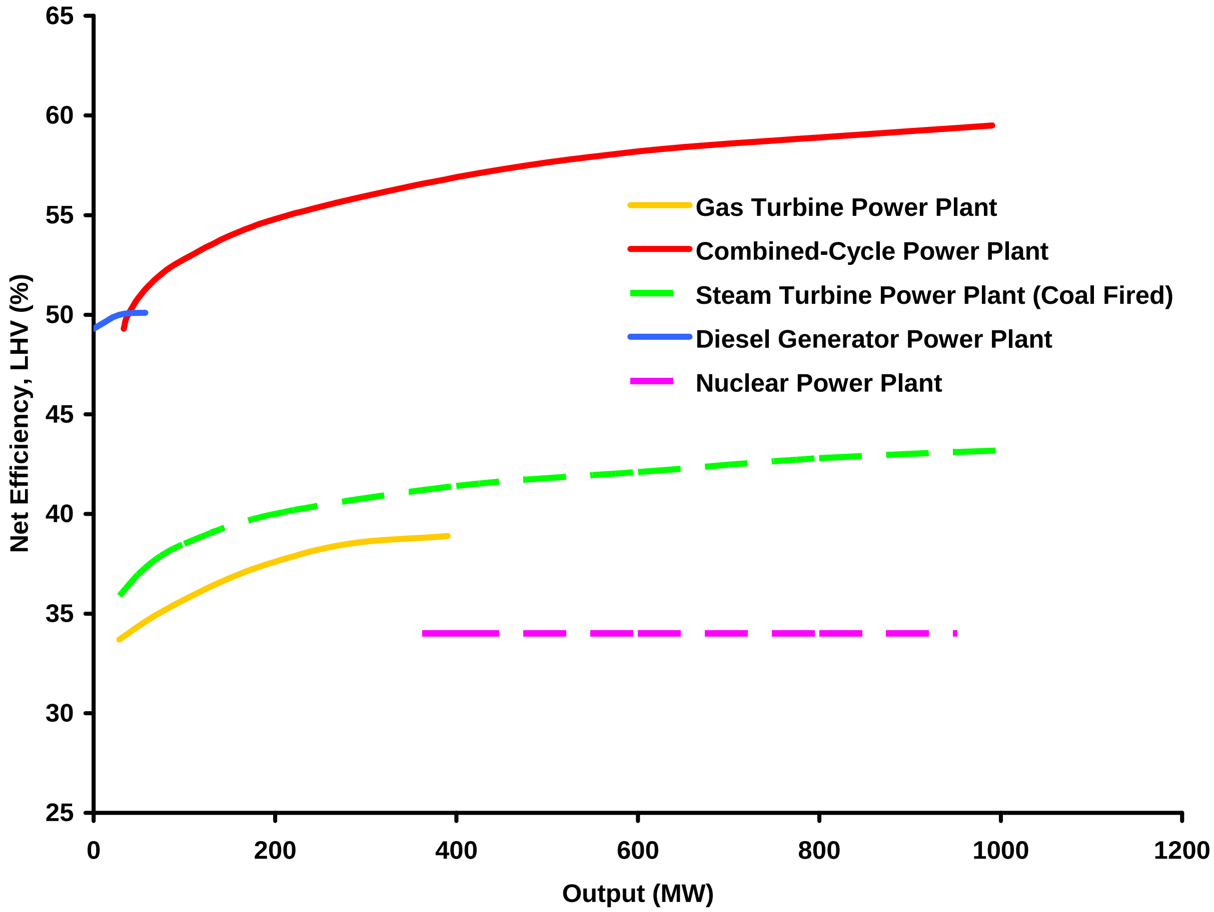


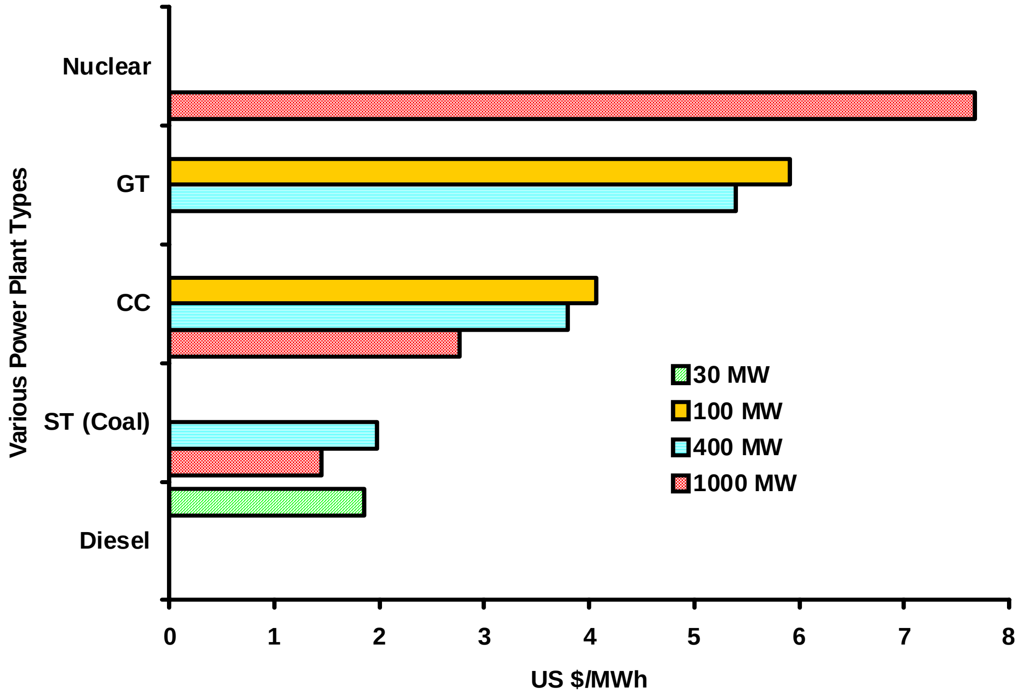
Figure: Net efficiencies for Gas Turbines, Combined Cycle, Steam Turbine (Coal Fired), Nuclear and Diesel Power Plants

When determining the specific fuel costs of power generation, efficiency is one factor. The other is the price of fuel - specifically, the fuel cost portion in the cost of electricity is the ratio of fuel price and efficiency. A power plant can remain competitive despite a low efficiency, when the fuel used is cheap.

Fuel selection and the corresponding type of power plant is determined not only by short-term economic considerations, but also in accordance with political criteria and assumptions about long-term developments in the prices of the various fuels available.

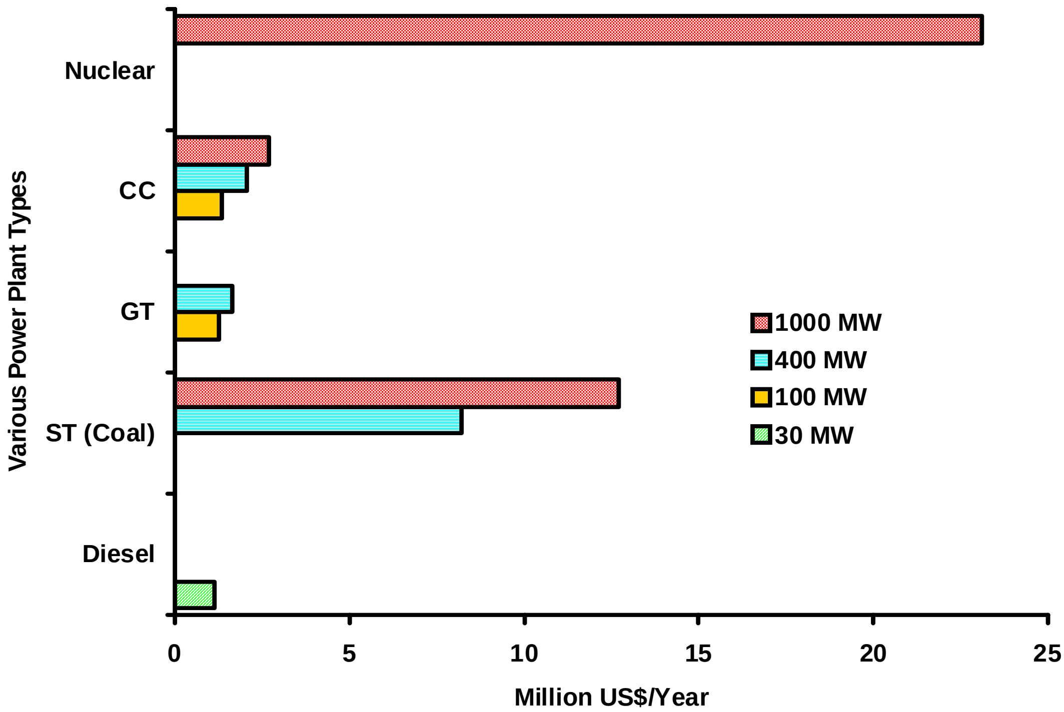
4.2.3 Comparison of operation and maintenance costs

At current levels of fuel and capital cost, operation and maintenance costs affect the economy of a power plant in a limited manner only. They strongly depend on site specific and local conditions and account for approximately a tenth of the cost of electricity in a combined-cycle plant. The following figure illustrates the variable operation and maintenance cost of the different power plants. Variable costs for a combined-cycle plant are lower than for gas turbine plants, because these costs are driven by the spare parts of the gas turbine, which can be distributed over a larger output in the combined-cycle plant. The next figure shows the fixed operation and maintenance costs of the different power plants.



GT Gas Turbine Power Plant
CC Combined-Cycle Power Plant
ST (Coal) Steam Turbine Power Plant (Coal Fired)
Diesel Diesel Generator Power Plant
Nuclear Nuclear Power Plant

Figure: Variable operating and maintenance costs for various power plants of different sizes



GT Gas Turbine Power Plant
CC Combined-Cycle Power Plant
ST (Coal) Steam Turbine Power Plant (Coal Fired)
Diesel Diesel Generator Power Plant
Nuclear Nuclear Power Plant

Figure: Fixed operating and maintenance costs for various power plants of different sizes

4.2.4 Comparison of availability and reliability

Reliability is the percentage of the time between planned over-hauls where the plant is ready to answer the call, whereas the availability is the percentage of total time where power could be produced.

Availability and reliability have a big impact on plant economy. When a unit is down, power must either be generated in another power station or purchased from another producer. In each case, replacement power is more expensive. The power station's fixed costs are incurred whether the plant is running or not. In deregulated markets, reliability is crucial. Typical figures for the availability and reliability of well designed and maintained plants are detailed in the following table.

Type of Plant	Availability	Reliability
Gas Turbine Plant (gas fired)	88 – 95 %	97 – 99 %
Steam Turbine Plant (coal fired)	82 – 89 %	94 – 97 %
Combined-Cycle Plant (gas fired)	86 – 93 %	95 – 98 %
Diesel Generator (diesel fired)	90 – 95 %	96 – 98 %
Nuclear Power Plant	80 – 89 %	92 – 98 %

Table: Availability and reliability of generating plants

These figures are valid for plants operated at base load. They would be lower for peak or intermediate-load plants, because frequent start-ups and shutdowns reduce lifetime and increase the scheduled maintenance and forced outage rates.

4.2.5 Comparison of construction time

The time required for construction affects the economics of a unit - the longer it takes, the larger the capital is employed without return, since construction interest, insurance and taxes during the construction period add to the price of the plant.

A gas turbine in a simple-cycle application can be installed within the shortest time frame because of its standardized design. Gas turbines therefore help secure power generation in fast-growing economies. Additional time is needed for the completion of a combined-cycle plant. Combined-cycle plants can be installed in a two phase installation process, with the gas turbine running first in simple-cycle mode, and then in combined-cycle mode as the steam cycle becomes available. With this procedure, two-thirds of the power is available in the time required for a gas turbine installation. However, an outage is needed to convert the gas turbine power plant from simple-cycle to combined-cycle mode. The typical time required for a combined-cycle is around 20 months (varying according required balance of plant).

4.2.6 Comparison of electricity costs

Based on the data presented the following three figures show the cost of electricity with a range of ratings from 100 MW to 1000 MW. Utilization times used in these figures were corrected with reliability of the individual types of plant to reflect that a forced outage disturbs operation and causes start-up and shut down losses and additional wear and tear on the equipment

The following conclusions can be drawn from these diagrams:

The main competition is among combined-cycle, gas turbine and coal-fired steam turbine power plants. This situation is unlikely to change in the near future.

For small-to medium-power outputs (up to approximately 30 MW), a diesel generator power plant can be a genuine alternative. The high efficiency of modern diesel engines is slightly less than combined-cycle with the same rating. To achieve a higher output with diesel generators, however, multiple units must be combined. Therefore, the diesel-based plant loses its attractiveness for higher power ratings, because investment costs are higher than those for combined-cycle power plants without compensating for that fact by providing greater fuel flexibility.

Conventional steam power plants are suitable for use as coal burning plants operating in base-load (or occasional intermediate-load duty) if cheap coal is available or gas is expensive (e.g. LNG) for a combined cycle plant. Whenever gas or oil is fired in a power station, the combined-cycle plant is more economical than the steam power plant due to its higher efficiency and lower specific price. Modern combined-cycle plants are simpler, less expensive, and operationally more flexible than steam power plants.

The choice between a steam power plant and combined-cycle plant for intermediate-to-base-load applications is a question of fuel availability and price. If natural gas is available and cheap, a combined-cycle design will be selected. If coal is the fuel, a steam power plant will be chosen.

However, recent trends in fuel price development show a higher increase with natural gas and oil prices than with the coal price. It is expected that this trend will continue due to the high demand for natural gas and the approach of mid-depletion points in some exploitation regions. This gives coal fired power plants a good perspective for the medium term future in the power sector.

For short utilization periods (peaking units), the gas turbine is most economical. Gas turbines can serve as intermediate - or base-load units in countries where fuel is abundant at low cost. The lack of water consumption has made this machine popular in dry regions. The short installation time allows a customer to plan a new installation on short notice.

If all fuels are readily available at world market prices, gas fired combined-cycle plants are the most economical solution for intermediate- and base-load applications. This results in a limited environmental impact (small heat rejection or low water consumption). With clean fuels like natural gas, this technology also achieves low emissions.

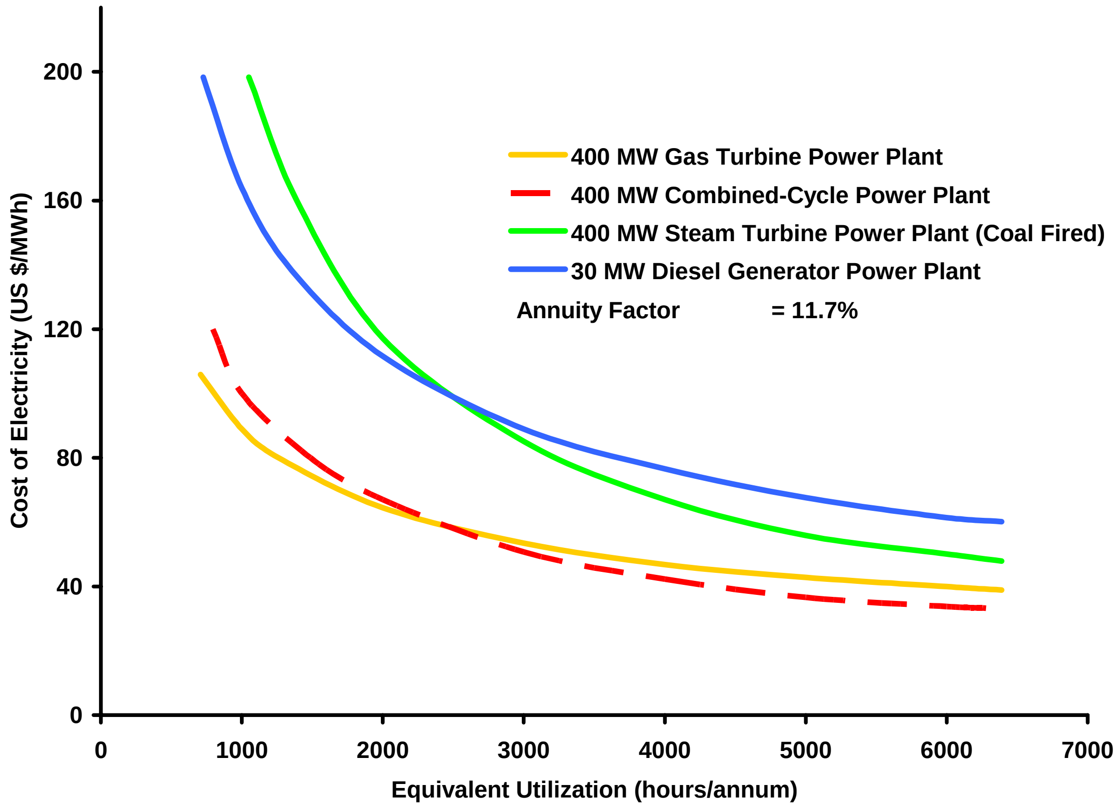


Figure: Dependence of the cost of electricity on the equivalent utilization time (small scale plants)

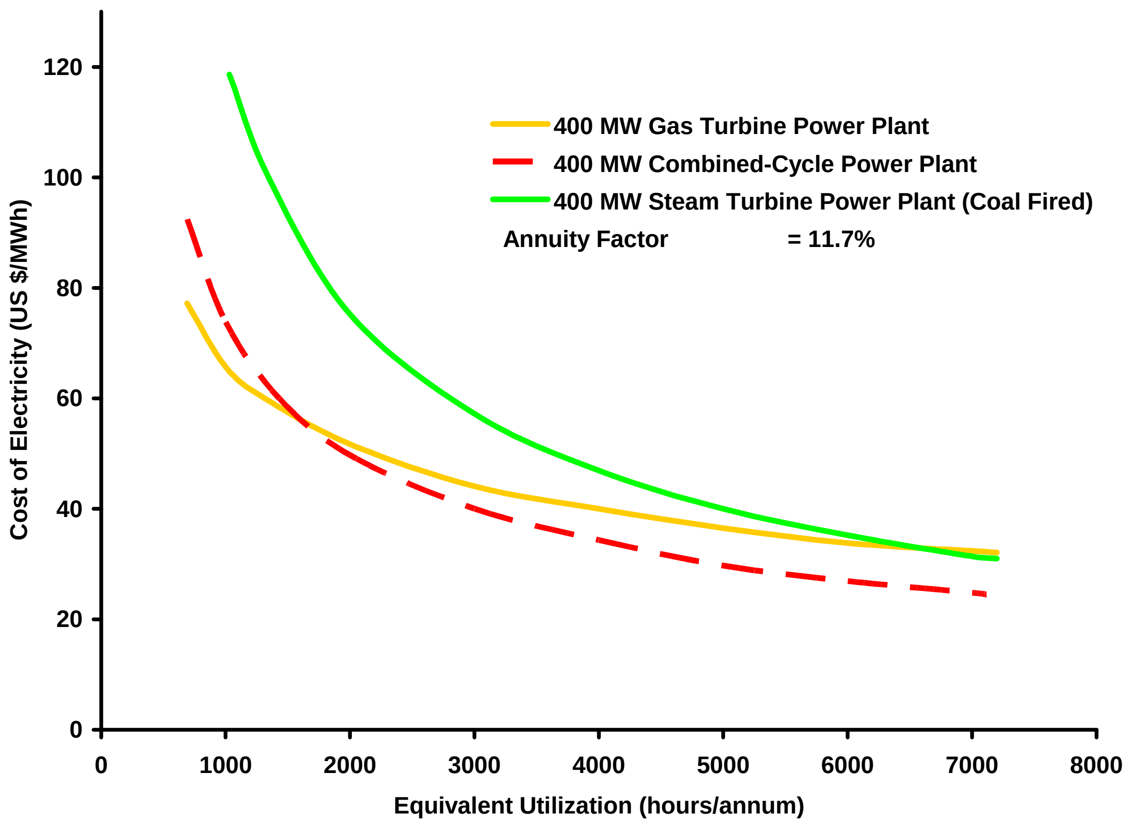


Figure: Dependence of the cost of electricity on the equivalent utilization time (medium scale plants)

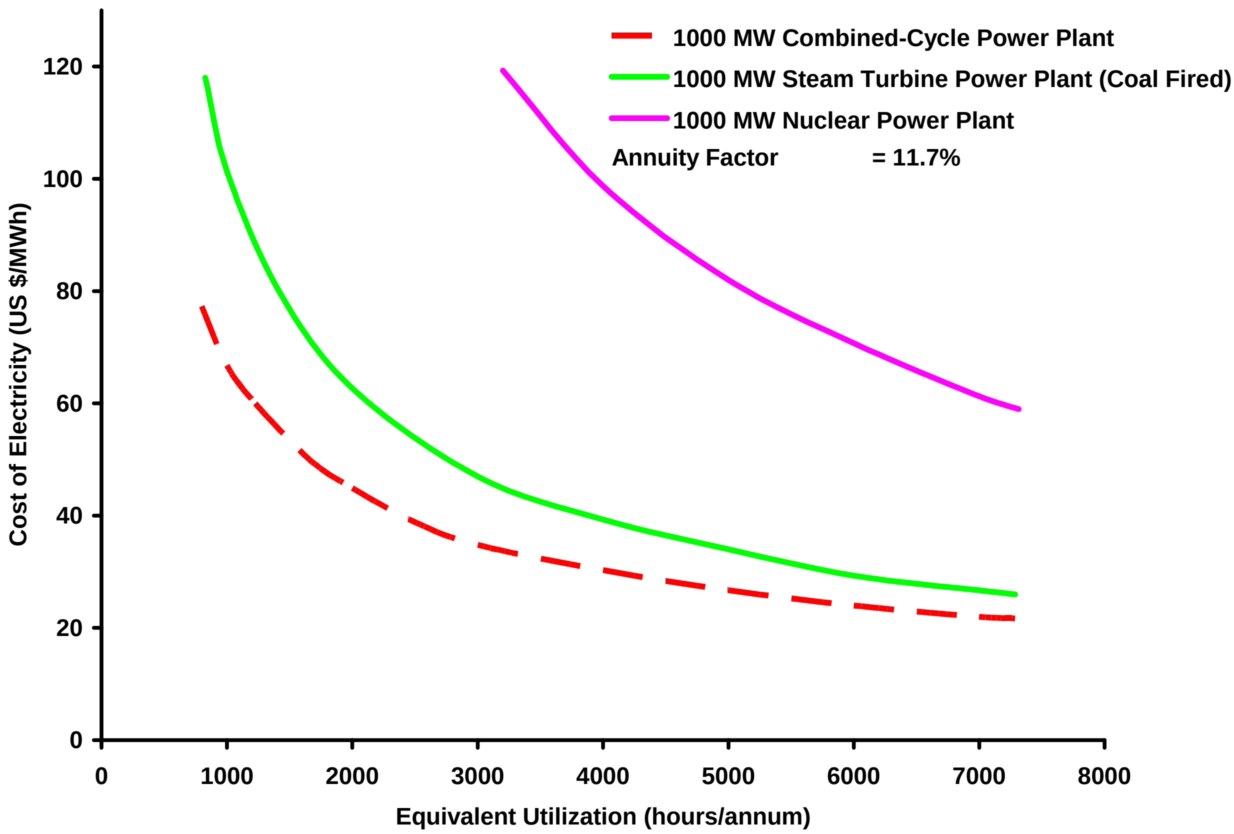


Figure: Dependence of the cost of electricity on the equivalent utilization time (large scale plants)

5 Glossary and list of abbreviations

$ - US Dollar

€ - Euro, 1 € ≈ 1.30 $

ACC - new EU Member States since 01.05.2004

AFBC - atmospheric fluidised-bed combustion

BAT - Best Available Techniques

b – barrel = 159 litres

bcm – billion cubic meter

b/d – barrels per day

BFB - bubbling fluid bed

BFBC - bubbling fluidised bed combustion

billion – 1,000,000,000 = 10^9 = Giga

bn – see billion

bkWh - billion kilowatt hours

BREFs - BAT Reference documents

BTU – 1 British thermal unit (Btu) = 0.252 kcal = 1.055 kJ

CCT - clean coal technologies

CCGT – combined-cycle gas turbine

CF – cubic feet = 0.028 m^3

CFBC - circulating fluidised bed combustion

CFT - clean fossil fuel technologies

CH_4 - methane

CHP – combined production of heat and power; sometimes, when referring to industrial CHP, the term “co-generation” is used

CO_2 – carbon dioxide

EC – European Commission

EIS – Environmental Impact Assessment Studies

ELCOGAS - in 1992, the environmental advantages of this coal gasification technology gained the support of the European Commission under the THERMIE Programme, as a targeted project. In addition, 8 major European utilities and 3 technology suppliers formed a consortium named ELCOGAS to manage the project.

ESPs - electrostatic precipitators

EU – European Union

FBC - fluidised bed combustion

FGD - flue gas desulphurisation

FTA – Free Trade Agreement

GHG – greenhouse gas

GJ – Giga-joule, 10^9 J

GTL - gas to liquid conversion (GTL) plants

GW – Giga-watt, 10^9 W

HFCs – hydrofluorocarbons

IEA –International Energy Agency

IGCC - Integrated Coal Gasification Combined Cycle

LA – Latin America; Argentina, Brazil , Bolivia, Chile, Colombia, Ecuador, Paraguay, Peru, Uruguay, Venezuela

LAC – Latin America and the Caribbean (see above)

LNB – low NOx burners

LNG – liquefied natural gas

m – million, 10^6

mb/d – million barrels per day, 10^6 b/d

MBTU - Million British Thermal Units

MCFD - million cubic feet / day

Mt – million metric tons, 10^6 t

Mercosur – countries of Argentina, Brazil, Paraguay, Uruguay

MW – Mega-watt of electricity, 10^6 W

MWh – Mega-watt hour, 10^6 Wh

N_2O - nitrous oxide

NGCC – natural gas combined cycle

OLADE – Organizacion Latinoamericana de Energia (Latin American Energy Organisation)

OPEC – Organization of Petroleum Exporting Countries

PF - pulverised fuel

PFCs – perfluorocarbons

PFBC - pressurised fluidised bed combustion

PRENFLO - the Gasification Unit is based on the PRENFLO system, an entrained-flow system with dry feeding. The syngas is produced by reaction of coal with oxygen at high temperatures up to 1600ºC. The PRENFLO process is capable of gasifying a wide variety of fuel types, and qualities of coal, for the production of synthetic gas. The “design” fuel of Puertollano power plant is a 50% mixture, by weight, of local high ash coal and high sulphur petroleum coke.

PSA – production sharing agreement

R&D – research and development, especially in energy technology; may include the demonstration and dissemination phases as well

RGC - Regional Generation Companies

SCR – selective catalytic reduction of NOx

SNCR - selective non-catalytic reduction of NOx

SF_6 - sulphur hexafluoride

SIEE - Economic-Energy Information System

Southern Cone – countries of Brazil, Argentina, Chile, Bolivia, Paraguay and Uruguay

tcm – thousand cubic meter

TCF – trillion cubic feet = 10^{12} cubic feet = 28 10^9 m^3

ton – metric ton = tonne = 1,000 kg

TPA – third party access

TPP - thermal power plants

TW – Tera-Watt, 10^{12} W

TWh – Tera-Watt hours

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CARNOT Programme
http://europa.eu.int/comm/energy/en/fa_13_en.html

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Commission on the Green paper "Towards a European Strategy for the Security of Energy Supply"
http://europa.eu.int/comm/energy_transport/en/lpi_lv_en1.html

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Directorate General Environment
http://europa.eu.int/comm/dgs/environment/index_en.htm

Directorate General External Relations
http://europa.eu.int/comm/external_relations/russia/intro/index.htm

EU Parliament: Committee on Industry, External Trade, Research and Energy
http://www.europarl.eu.int/committees/itre_home.htm

European Association for the Promotion of Cogeneration (Cogen Europe)
http://www.cogen.org/

European Atomic Forum (Foratom)
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European Petroleum Industry Association (EUROPIA)
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European Renewable Energy Council (EREC)
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European Transmission System Operators (ETSO)
http://www.etso-net.org/

European Union of Natural Gas Industry (Eurogas)
http://www.eurogas.org/

European Wind Energy Association (EWEA)
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Organisation for Economic Co-operation and Development (OECD)
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Secretariat of the Energy Charter
http://www.encharter.org

Union for the Co-ordination of Transmission of Electricity (UCTE)
http://www.ucte.org/

Union of the Electricity Industry (Eurelectric)
http://eurelectric75.atalink.co.uk

United Nations Environment Programme (UNEP):
http://www.unep.org/

VICEMINISTERIO DE ENERGIA Y HIDROCARBUROS –BOLIVIA
http://www.energia.gov.bo

7 Annex 1 – Characteristics of Gas Turbines

	Model	ISO Based Load (kW)	Heat rate Btu/kW-hr	LHV efficiency (%)	Budget price ($)	$ per kW
Solar Turbine	Titan 130	13,500	10,250	33.3	4,700,000	348
Rolls Royce	Trent 60	58,000	8,370			
Pratt&Whitney	FT8 PowerPac	27,970	8,900			
Rolls Royce	Avon	14,580	12,100	28.2	5,175,000	355
GE Power System	LM6000 Sprint Intercooler	47,300	8,250	41.4	14,100,000	259
Alstom Power	GT 8C	52,800	9,920	34.4	15,100,000	285
Alstom Power	GT8C2	57,200	9,750	35.0	19,100,000	281
Siemens	V64.3A	68,000	9,690	35.2	16,500,000	262
Alstom Power	GT11N2	114,500	9,780	34.9	22,800,000	200
Siemens	W501D5A	122,480	9,730	35.1	24,500,000	200
Siemens	V94.2	159,000	9,890	34.5	29,890,000	188
Alstom Power	GT13E2	165,100	9,550	35.7	33,850,000	205
Alstom Power	GT24	183,000	8,910	38.3	36,400,000	199
Siemens	W501F	186,160	9,066	37.6	37,000,000	199
Siemens - Westinghouse	V94.3A	190,000	9,375	36.4	36,100,000	190
Siemens - Westinghouse	W501G	243,500	8,700	39.2	46,000,000	189
Alstom Power	GT26	265,000	8,895	38.4	50,350,000	190
MHI	M701F	270,300	8,930	38.2	50,275,000	186
MHI	M701G	334,000	8,630	39.5	60,120,000	180
GE Power System	PG9351 (FA)	255,600	9,250	36.9	48,560,000	190
GE Power	PG6101	70,150	9,980	34.2	20,000,000	285

	Model	ISO Based Load (kW)	Heat rate Btu/kW-hr	LHV efficiency (%)	Budget price ($)	$ per kW
System	(FA)					

Table: Gas Turbine Characteristics and Budget Price Levels (Source: Gas Turbine World (January - February 2002)

	Plant Model	ISO Based Load (MW)	LHV efficiency (%)	Nº Gas Turbines	Budget price ($)	$ per kW
GE Power System	S-206FA	218.7	54.1	2xMS60016FA	103,000,000	471
GE Power System	S-109FA	390.8	56,7	1xMS9001FA	139,100,000	356
Alstom Power	KA26-1	393.0	58.5	1xGT26	140,500,000	358
Alstom Power	KA13E2.2	485.7	53.2	2xGT13E2	166,000,000	342
Alstom Power	KA 10C-1	41.28	51.1	1xGT10C		
Siemens Power Generation	1S.V94.3A	392.20	57.4	1xV94.3A		
Siemens Power Generation	2 V94.3A	783.90	57.3	2xV94.3A		
MHI	MPCP2 (M701G)	981.90	58.9	2xM701G		
MHI	MPCP1 (M701G)	489.30	58.7	1xM701G		
MHI	MPCP2 (M701F)	799.60	57.3	2xM701F	236,900,000	296
	MPCP2					

	Plant Model	ISO Based Load (MW)	LHV efficiency (%)	Nº Gas Turbines	Budget price ($)	$ per kW
MHI	(M701F)	397.70	57.0	1xM701F	139,200,000	350
GE Power System	S209FA	786.90	57.1	2xMS9001FA	242,100,000	308
GE Power System	S109H	480.00	60.0	1xMS9001H		
Siemens Power Generation	1S.V94.2A	294.30	55.1	1xV94.2A		
Siemens Power Generation	2S.V94.2A	587.60	55	2xV94.2A		

Table: Combined Cycle Characteristics and Budget Price Levels (Source: Gas Turbine World January - February 2002)