Coal Fired Unit versus Natural Gas Combined Cycle

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Coal Fired Units Emissions are today approaching in Europe the Emissions of Natural Gas Fired Combined Cycles.

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The main addressed objectives of this paper are: underline advantages and disadvantages of the techincal alternatives of coal and natural gas plant; evaluate the capital costs and revenues of these two alternatives; emphasize that by now coal fired units emissions are approaching the emissions of the combined cycle, but in the near future with the coming of the zero emission technology any difference could be removed.
Finally, this paper will discuss what could be the position of an investor today in respect to the development and opportunities of the CCS (Carbon Capture Sequestration) technologies.

Confronto tra impianti alimentati a carbone e a gas naturale in ciclo combinato
I principali scopi di questo articolo sono: illustrare i vantaggi e gli svantaggi di due tipologie di impianti alimentati con carbone e con gas naturale; valutare i costi di investimento delle due alternative; mettere in rilevo il fatto che le emissioni delle nuove unità alimentate a carbone sono molto simili alle emissioni delle unità a gas a ciclo combinato e che in un prossimo futuro, con l'entrata in servizio delle unità a carbone"zero emission", non vi saranno differenze.
Infine, questo articolo illustra quale potrebbe essere la posizione di un investitore di oggi di fronte agli sviluppi e alle opportunità offerte dalle tecnologie CCS (Carbon Capture Sequestration).

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The economic development of one country is dependent upon the ability of the authorities to set up a highly suitable, competitive and reliable electricity sector.
It is well known that Italy, where in 2010 more than 56% of electricity will be produced by natural gas, is the European country having the most expensive and unbalanced fuel mix in the electricity production sector.
The main disadvantages for Italy from this unbalanced fuel mix are:
- higher electricity cost in respect to other western countries; this high Italian kWh cost reduces the competitiveness of many energy intensive industry productions;
- potential risk of electricity shortage in case of interruptions of natural gas supply from one of the three main Italians suppliers (Algeria, Libya and Russia).

The main reasons of this fuel natural gas oriented policy in Italy have been:
- strong opposition to the conventional coal fired units from the green associations and from the local authorities, asserting that coal is more polluting in respect to natural gas;
- higher capital cost required for the construction of coal fired units;
- halt in 1988, after a referendum, of all nuclear construction, shut of the existing reactors and their decommission from 1990 (the only country in the world).

Recent reduction of natural gas supply within the 2005 and 2006 winters and political crisis among Russia and its nearby countries concerning the gas prices, pushed Enel to increase its investments in new or retrofitted coal fired units, but also Italian IPPs started to take in due consideration the coal alternative.
Within this framework IPG finalized a feasibility study on behalf of a new Italian IPP interested to compare for its brown field site a natural gas combined cycle plant with a coal fired unit preparing also technical documents for the debate with local and government authorities and with green associations so to obtain the permits required by the Italian laws.
The main addressed objectives of this paper are:
- underline advantages and disadvantages of the above mentioned alternatives that is

coal and natural gas;
- evaluate the capital costs and revenues of these two alternatives;
- emphasize that by now coal fired units emissions are approaching the emissions of the combined cycle, but in the near future with the coming of the zero emission technology any difference could be removed.

Finally this paper will discuss what could be the position of an investor today in respect to the development and opportunities of the CCS (Carbon Capture Sequestration) technologies.

1. Comparing Coal and Natural Gas Technology Alternatives

Electricity is generated, in accordance with demand, in peaking or base-load plants and transported over long distances to reach the consumer at the required voltages.
Today the fossil fuel options are natural gas and coal and the technology options are coal fired conventional plants, coal fired IGCC and natural gas fired combined cycles. Heavy fuel oils are less used in the conventional plants, due to the high purification cost of their exhaust gas and due also to their higher cost in respect to coal. Distillate oil is used in the combined cycles usually only during start up or as secondary fuel, due to its higher cost in respect to natural gas and due to the consequent increase of gas turbines maintenance costs.

Table 1 - Differences between coal and natural gas alternatives for new electric generation capacity decisions

	Coal-Fired Plant	Gas-Fired Plant
Fuel	Low cost fuel	More expensive fuel
Investment	More costly initial plant	Less costly initial plant
Emissions control	More investment	Lower investment and emits very low SO_2
Emissions level	Emissions of coal fire units are becoming day by day near to the emissions of Gas-Fired Plants	Permits for new US gas fired plants typically require lower emissions in respect to similar plants in Europe (3 ppm NOx and single-digit CO) (note)
ZEP (Zero Emission Projects): the new frontier	Emissions will become equivalent to the Gas Fired plants emissions and new technologies are expected	Gas Fired Plants could remain competitive in respect to Coal Fired Plants, if their efficiency will increase

Note: US gas turbines have DLN systems capable of operating at less than 5 to 8 ppm NOx and catalyst must be used in addition to attain limits.
All triple-pressure US HRSGs are equipped with SCR and CO catalyst beds.

1.1 Coal versus Natural Gas

Coal-based technologies offer a significant fuel price advantage over its natural gas based competitors to virtually any power plant location. On the other hand, natural gas based technologies have a capital cost advantage over coal technologies.
Given these differences, the market areas for the generating technology and fuel choice decisions become quite clear. One simple way for defining these market areas is defining how large must be the coal fuel price advantage over gas to justify coal's plant higher capital cost. Looking in details, the market choice between coal and gas is sensitive to the type of power that is required. "Peaking" power capacity is required to meet high air conditioning loads in the summer and high heating loads in the winter, but this not in Italy where usually heating is made using natural gas. This peaking capacity is usually used only a limited portion of time and its choice is dominated by capital cost considerations. So, natural gas turbine's large capital cost advantage will continue to make it the dominant choice for utilities to meet expanding peaking load requirements.
On the other hand, "base load" power capacity is required on-line for long time to meet the bulk of the electrical system demands.
Fuel cost dominates the selection of the base load technology, because fixed capital costs become less significant when spread over a larger generation baseline.
Price differentials between coal and natural gas are projected to grow larger in the next future.
While coal prices are expected to remain stable (depending also upon region and coal quality) natural gas prices are expected to increase as higher cost natural gas reserves need to be developed to meet growing demand and offset losses from depleting gas wells. Higher natural gas prices will be needed to support development of new gas reserves. Another factor increasing the cost of the natural gas is its high transportation cost both through pipeline line or through the liquefied natural gas chain.

Table 2 - Overview of the coal market in Italy

Fuel Type	Estimated Conventional Guaranteed supply (years)
Oil	**41**
Natural Gas	**64 (note)**
Coal	**234**

Note: this value could be reduced in case of a too quick increase of natural gas consumption

In Italy green associations and local authorities are opposing the coal choice, basing on the fact that coal is dirty and its environmental impact is more dangerous in respect to natural gas. For this reason in Italy combined cycles provide also base load power and in 2010 more than 56% of electricity will be produced by natural gas.
A chapter of this paper will be dedicated to compare the emissions of the natural gas combined cycle with the emissions of the coal fired conventional units and IGCC plants.
Due to the improvements of the exhaust gas purification technologies coal fired conventional plants emissions start today to approach in Europe the combined cycle emissions, on the contrary the emissions of the coal fired IGCC can be today also lower of the cc emissions.
Unlike natural gas, coal is not suitable for dispersed on-site use. Coal can be used most effectively where it permits the user to enjoy the economics of scale of large units and coal delivery by ship, barge, unit train or conveyor (for a mine mouth plant).
The differences between coal and natural gas alternatives for new electric generation capacity decisions are reported in *table 1*.
An overview of the coal market in Italy indicates that coal supply is safer in respect to the other fuels for the following reasons (*table 2*):
• coal reserves are abundant and distributed in more than 100 countries, while oil and gas reserves are concentrated within few countries and many of these countries are politically instable;
• high availability of coal extraction, transportation, storage and handling systems on worldwide basis.
Abundant coal reserves in many countries can be mined well into the next century at costs (in constant $'s) very close to today's production costs. The best evidence for this is that new coal mines are and will continue to be added at a very full production cost very close to the production costs of the existing mines they are replacing.
Figures 1 and 2 indicate, rispectevely, the natural gas and coal price trends from 1995 to 2005 (Cif = cost + insurance + freight). These figures show that the gas prices rise more quickly in respect to coal prices.

1.2 Fuel Transportation

Fuel transportation costs are also an important factor in the utility fuel selection. These costs can vary significantly by plant location, utility ability to promote inter-carrier competition and distance between fuel source and plant. The cost to transport coal is ranging from $ 0.60 to 0.85/million BTU for long distances. But due to the dispersion of coal reserves, coal transport costs are usually less than these amounts and are ranging between $ 0.10 to 0.30/million BTU. Gas pipeline transport costs also vary widely depending upon distance and location. They can range from $ 1.50/million BTU to $ 2,5/million BTU or higher and have an impact ranging from 30% up to 50% on the total gas price.

1.3 The Technology Choices and Their Costs (excluding CCS)

Plant capital costs are significantly different between the coal and the natural gas fired power generation options.
Natural gas based technologies have lower capital costs than coal based technologies and this difference is also depending from the technology selected for coal generation option.
This capital cost advantage of the NG plants is ranging between $ 500 to $ 1000/kW depending upon the assumptions used that is fuel source, required by authorities environmental limitations, selected technology for the coal fired plant, major equipment redundancy, plant site location and labor cost on the plant site.
The main technologies that are competing today on the market are the following.

Fig. 1 – Cost trends of natural gas from 1995 to 2005

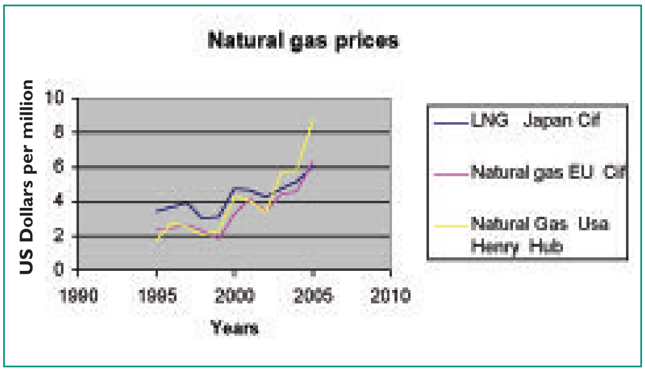
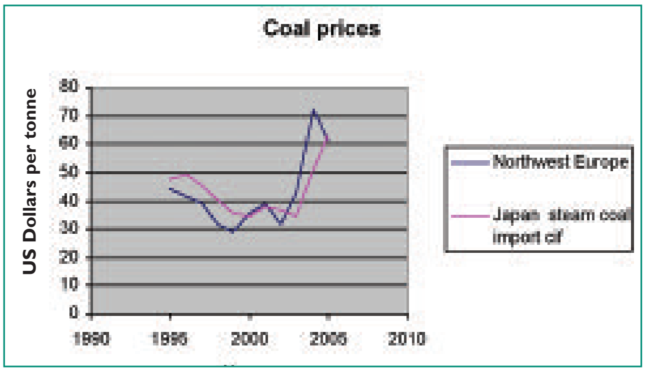


Fig. 2 – Costtrends of coal from 1995 to 2005



1.3.1 Natural Gas Combined Cycle

The combined cycle is the basic gas-fired technology that consists of gas turbines discharging hot exhaust gases into recovery boilers producing high pressure steam which operates a steam turbine. Both the gas turbine and the steam turbine move one or two electrical generators which generate electricity. For example a large 800 MWe plant of this technology costs around 600 $/kW.

The gas fired combined cycle is the most efficient commercial technology with heat rates (LHV) of only 5880 BTU/kWh (58% efficiency), but further improvements are expected in the near future. However, the natural gas heat rate is sensitive to unit operations and can decline to a lower energy efficiency if operated at loads of 50% of the rated capacity. At low loads emissions also increase, because the dry low NOx combustion systems is not in operation.

1.3.2 Conventional Pulverized Coal Fired Plant

The key components of a conventional coal fired plant are the steam generator and the steam turbine that are interconnected by the thermal cycle, where the water coming from the condenser is heated in dedicated feedwater heaters supplied by steam extracted from the steam turbine. The two main options are the subcritical and the supercritical cycles. Today supercritical components reached very good availability so these cycles are the most adopted by the utilities also due to their higher efficiency in respect to subcritical cycles.

These new conventional coal-fired steam electric generating plants employ advanced pollution controls to meet very strict environmental requirements for particulates, sulfur dioxide, mercury and NOx. The capital cost of new conventional coal-based technology was in 2003 approximately $1200/kW. As well known the boiler market situation resulted mainly in Europe in the nineties in the bankruptcy of important manufacturers. This big crisis loomed over this sector up 2004, forcing the surviving boiler makers to reduce their manpower and costs in order to get out from this downturn. Due to the very high demand in 2006 coal fired boiler prices moved up and a shortage of critical materials contributed also to this increase of boiler prices and to the extension of their delivery times. For example prefabricated P92 pipes delivery moved during 2006 from 12 to 22 months. Today the capital cost of a new conventional is in Europe around $1400 - 1600/kW.

Compared to the conventional subcritical plant's 36-38% efficiency, a sea water cooled supercritical plant can readily achieve 45% on an LHV basis.

Recently EON announced they will build the world's most innovative coal-fired power plant by 2014 with an efficiency of more than 50% and with superheater temperatures up to 700 °C, using nickel-based alloys, instead of conventional steel for the key components of boiler and steam turbine. Increasing efficiency is one of the best strategies to reduce coal consumption, but it is also the way for zero emission plants.

1.3.3 Integrated Gasification Combined Cycle Plants (IGCC)

Coal gasification is a process that converts solid coal into a synthetic gas composed mainly of carbon monoxide and hydrogen. Coal can be gasified in various ways by properly controlling the mix of coal, oxygen or air, and steam within the gasifier. Manufacturers offer several technology options for controlling the flow of coal in the gasification section (e.g. fixed bed, fluidized bed, and entrained-flow systems). Most gasification processes being in commercial operation use oxygen as the oxidizing medium.

IGCC combines a fossil fuel gasification system with a combined cycle. Depending on the level of integration of the various processes, IGCC was achieving 40 to 42% efficiency.

Most of the IGCC plants use entrained gasifiers (e.g. Texaco-GE, Krupp Uhde and Shell technologies).

Many companies including IPG [1, 2] presented interesting improvements of the existing IGCC processes, but these improvements had not success up to now, because the efficiency increase to around 46%-47% do not justify the higher cost of this technology.

IGCC cost projections range from US$1800 to $2100/kW; 20 to 30% higher than for the pulverized coal plants equipped with wet scrubbers and DeNOx. It is also important to note that about 50% of IGCC is chemical plant, on which the electric utilities operation staff do not have experience and that finally IGCC has higher O & M costs in respect to the pulverized coal plants.

IGCC was indicated within the nineties the technology of choice due to the opportunity of high removal of SO2 (e.g. 99% or higher) and of all other coal pollutants.

Today the removal efficiency of the De-SOx and De-NOx systems improved and the emissions of new pulverized coal plants are lowering day by day.

An interesting opportunity could be offered

by the Integrated Gasification SOFC (Solid Oxide Fuel Cells) combined cycle that can offer a net thermal efficiency of 54% HHV [3]. On the contrary IGCC remains the most suitable technology to produce clean fuels and/or electricity from the refinery residues [4].
The time for construction of IGCC is similar to PC plant including also DeSOx and DeNOx. However, phased construction (erection of the gas turbine first, followed by the gasifier) can improve the economics of the IGCC plant by producing power as soon as the gas turbine is constructed.

2. ZEP (Zero Emission Projects) and CCS (Carbon Capture Sequestration)

Within energy sector the mankind must urgently trying to:

- reduce the greenhouse gases emissions produced by the combustion of the fossil fuels;
- increase the fossil fuel reserves, basing on the fact that fossil fuels will be with us for long time to come, probably for the next 50 or 80 years at least.

The European Union sponsored ZEP (Zero Emission Project) looks the right answer to solve these problems. This ZEP is based on the main idea to capture the CO_2 produced by the fossil fuel combustion and subsequently sequestrate this CO_2 mainly within the existing oil wells to enhance oil and gas production, but also within other underground storage facilities as for example the aquifers.
This is an ambitious goal, but an entirely feasible one. After all, this CCS technology has been practiced over decades – CO_2 in fact has been separated from gaseous streams for several years in many industries. It has also been used and stored extensively in Enhanced Oil Recovery (EOR).
Obviously, substantial R&D is required, not only to reduce the cost and increase the efficiency of CO_2 capture technologies, but to demonstrate the safety and feasibility of large-scale CO_2 geological storage.
What are the competing carbon capture technologies? Here the list of the most promising.

2.1 Oxy-fuel Combustion

One of the interesting economical solution to capture CO_2 is to switch to oxy-fuel combustion. The use of oxygen in place of air results in a much lower volume of flue gas, which enhances thermal efficiency, lowering also CO_2 emissions.
Among the possible process opportunities we can consider the following alternatives.

2.1.1 Use of Oxy-fuel in a Conventional Power Plant Standard Boiler

Literature indicates that furnace absorption increases by some 10–12% due to an increase in radiating power of the hot flue gas and that the furnace exit gas temperature also is reduced.
Approximately one third of the boiler exit flue gas feeds the CO_2 compression system via the gas cooler and the CO_2 treatment. The remaining two-thirds of this flue gas is returned to the boiler unit by a Flue Gas Recycle (FGR) fan to moderate the combustion temperatures.

2.1.2 Integration of Oxygen Transport Membranes (OTM) into Oxy-fired Boiler

This project has been funded by US DOE coupling the Praxair's expertise in OTM development and oxy-fuel combustion with the experience of Alstom Power in boiler development and manufacturing.
Gasification plants which integrate this OTM technology will have higher efficiency, lower cost of electricity, and lower emissions of pollutants compared to using a conventional cryogenic air separation system unit.

2.1.3 Gas Turbine Oxy-fuel Combustion

This process use pure oxygen as the oxidant. Burning natural gas the combustion products consist primarily of CO_2 and H_2O and also, with N_2 removed from the cycle, there will be no generation of NOx.
In this case it is important to note that re-circulated CO_2 used as working fluid has a negative impact on the performance of current gas turbines. In effect being the sound speed of CO_2 approximately 80% of air, choking is likely to be encountered for operation at current synchronous speeds (3000/600 rpm) using current GT compressors.

2.2 Post-combustion Capture

Post-combustion capture is focusing on the amine scrubbing processes that are the most interesting technologies available to approach the scale required for CO_2 capture within fossil fired power generation plants.
These alkanolamines are the most usual employed as suitable solvents for H_2S and CO_2 removal. The amines can be divided as primary, secondary and tertiary according to the number of the hydroxil groups bound to the amine nitrogen.
The best known among the primary amines is

the monoethanolamine and among the tertiary the triethanolamine.
The Fluor Econamine FGSM technology uses a monoethanolamine (MEA) formulation specially designed to recover CO_2, including an inhibitor which protects the equipment against corrosion.
This allows the use of carbon steel for the component construction.
Mitsubishi Heavy Industry proposes the KS1 solvent having a sterically hindered amine formulation. This KS1 and the improved KS2 and 3 looks having less problems with the degradation and corrosion issues and a much lower specific stripping heat requirement than MEA.

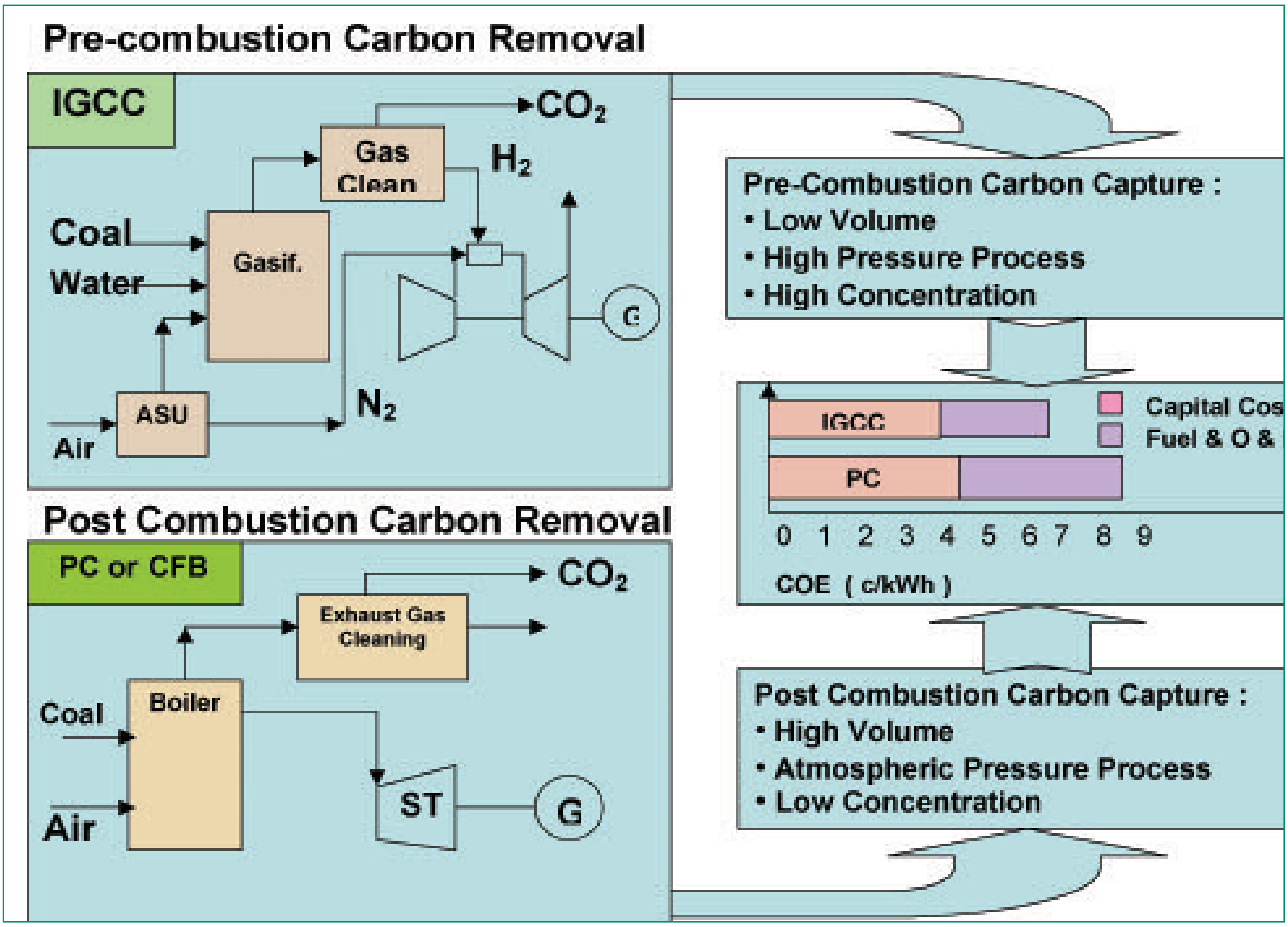
2.3 Pre-combustion Capture

IGCC was considered within eighties the technology of choice for the production of electricity from coal, but this expectation was reversed mainly due to the increase of the performances of the conventional plants (efficiency increase to 45%, expected efficiency increase to 50% by 2014 and continuous reduction of their environmental impact).
IGCC efficiency increases are expected, but not in a short term.
The advantages of this pre-combustion de-carbonization technology in respect to the post-combustion are

- IGCC provides the best environmental performances with respect to organic and inorganic pollutants. In effect, IGCC is the cleanest fossil fuel technology in the market. IGCC could be a real zero emission plant, selecting suitable raw gas purification technologies that are in use in chemical industry. But obviously plant cost will increase;
- pre-combustion de-carbonization of syngas offers intrinsic advantages in respect to post-combustion de-carbonization, because the gas volume is limited and the carbon capture is performed at high pressure and high concentration. *Figure 3*, which indicates a comparison as provided by the US DOE in 2000, shows that IGCC offers a net COE, including O&M and capital costs, approximately 20% lower than that of a conventional combustion plant.

On other hand quite half of the IGCC is a chemical plant, where usually electric utilities have limited experience.

Fig. 3 - Pre-versus-post combustion decarbonization (cost of electricity) [7]



Items	Units of measurement	Operating Data 2 GT in service	Operating Data 1 GT in service
Fuel : natural gas	kcal/Scum	8600	8600
Gross thermal power capacity	MWt	1452	722.5
Gross electric power capacity	MWe	822	406.8
Net electric power capacity	MWe	806	400
Net efficiency (LHV)	%	56.62	56.3
Exhaust gas flow rate	Scum/h	3,700,000	1,825,850
SO2	mg/Scum	-	----
NOx	mg/Scum	25	25
CO	mg/Scum	20	20
Solid particulate	mg/Scum	-	-
Working hours/year	hours	7000	-
Electricity Production	MWh/year	5,642,000	-
Fuel Consumption	Scum/year	142,000	70,073
Net Heat Rate (LHV)	kcal/kWh	1519	1527.5
Condenser Pressure	bara	0.12	0.12

Table 3: Operating data of a combined cycle equipped with dry air cooled condenser

Items	Units of measurement	Operating Data	Notes
Fuel : imported coal	kcal/kg	6400	
Gross thermal power capacity	MWt	1600	
Boiler efficiency	%	94.33	
Gross electric power capacity	MWe	680	
Net electric power capacity	MWe	636	
Net efficiency (LHV)	%	42.5	
Exhaust gas flow rate at air heaters outlet (temp °C 121)	tons/h	2360	Flow rate corrected for air leakage
Main steam flow	tons/h	1944	
Main steam temperature	°C	600	
Main steam pressure	bar	262	
Reheat steam flow	tons/h	1635	
Reheat steam temperature	°C	610	
Reheat steam pressure	bar	54.5	
Feedwater temperature at boiler inlet	°C	310	
SO_2	mg/Scum	100	@ 3.5% O_2 v/v, dry
NOx	mg/Scum	100	@ 3.5% O_2 v/v, dry
Solid particulate	mg/Scum	20	@ 3.5% O_2 v/v, dry
Working hours/year	hours	7000	
Electricity Production	MWh/year	4,452,000	
Fuel Consumption	tons/day	4850	
Net Heat Rate (LHV)	kcal/kWh	2018	
Condenser	bara	0,084	

Table 4: Operating data of a Supercritical unit equipped with dry air cooled condenser

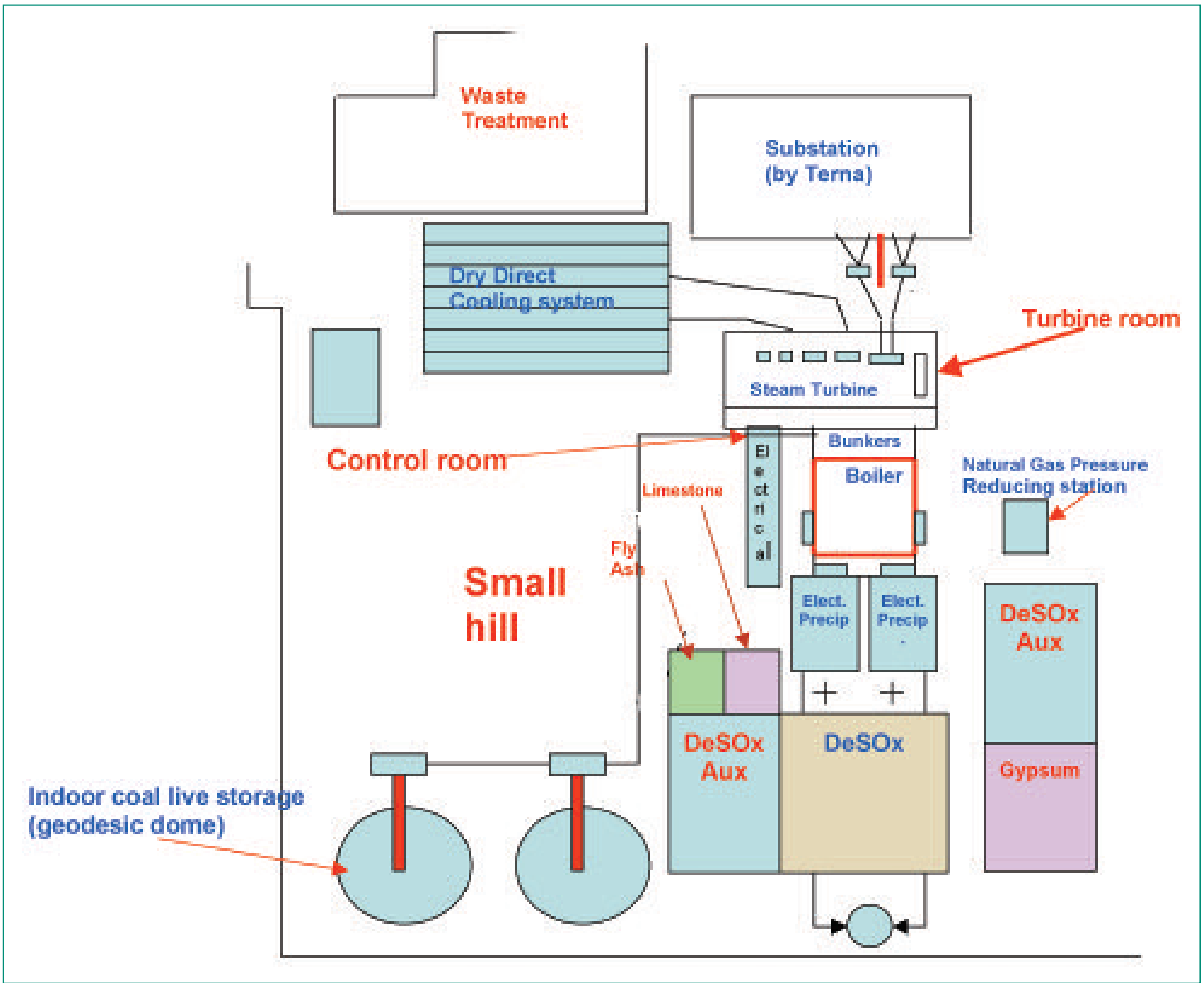


Fig. 4 - Preliminary 660 MWe unit layout

In addition the IGCC commissioning period is quite longer of that of the conventional plants and the IGCC availability is lower mainly during the first years of life of these plants.
IGCC availability is low also due to poor plant standardization that could be improved standardizing an IGCC plant on EU basis.

3. An Italian Case: the IPG Feasibility Study

The site of this plant is located in the North of Italy at about 20 km from the sea side. This site has been selected due to its local facilities, including an existing transportation system of coal from a nearby harbour and a large area suitable for this plant and not usual in this Italian mounting region.
This study has been split into the following phases:

- preliminary design on this site of a 800 MWe natural gas combined cycle and of a 660 MWe coal fired conventional supercritical unit;
- definition of the capital and operating cost of the cc versus the conventional unit;
- comparison of the emissions of the cc versus the coal fired conventional unit;
- comparison of the COE of the cc versus the conventional unit.

3.1 Preliminary Design on this Site of a 800 MWe Natural Gas Combined Cycle

The power island is equipped with two gas turbines, two heat recovery steam generators and one steam turbine.
The operating performances of this plant are indicated in the *table 3*.
This plant is rigged with a direct dry air cooled condenser equipped with 20 modules.
The maximum electrical power consumption of this condenser is expected to range from 2,5 to 3 MWe. The water consumption including the auxiliary evaporation towers, the

thermal cycle makeup and minor additional requirements is ranging from 50 to 55 t/h.

3.2 Preliminary Design on this Site of a 660 MWe Coal Fired Conventional Supercritical Unit

The unit rating and steam conditions have been chosen according to Italian standardization.
This unit will be equipped with:

- two pass balanced boiler arranged for pulverized coal firing;
- advanced De NOx SCR systems with 85% efficiency;
- advanced fabric filters with a 99,9% efficiency;
- advanced humid limestone/gypsum De SOx with a 97% efficiency;
- coal stock system equipped with two geodesic domes designed for a capacity of about 35,000 m3 each that means the operation of this unit for about ten days. The coal shall be delivered to this dome through a fully closed belt conveyor system.
- direct dry air cooled condenser equipped with 45 modules. The maximum electrical power consumption of this condenser is expected to range from 5 to 5,6 MWe.

The operating performances of this plant are indicated in the *table 4*.
The water consumption including the auxiliary evaporation towers, the thermal cycle makeup, gypsum washing, scrubber make up and minor additional requirements is ranging from 150 to 160 t/h.
The preliminary layout of this supercritical unit is indicated in *figure 4*. This layout has been subsequently modified to obtain a better fitting with the site.

4. Combined Cycle Versus Supercritical Coal Fired Unit Emissions: as Today

The main pollutants of the electrical thermal power plants are NOx, SO_2, CO and particulate.

4.1 Nitrogen Oxide Emissions

European gas turbines manufacturers usually guarantee NOx emissions < 25 ppm using DLN combustion systems in steady state conditions with load ranging from 50% to 100%.
It is interesting to note that US gas turbines manufacturers produce 9 ppm combustion systems for the US market. But US Authorities impose to reduce NOx emissions at 3 ppm using SCR.
The gas turbines NOx emissions are referred to a 15% O_2 content in the flue gas on dry basis.
With reference to coal fired power plants EU standards request NOx emissions lower of 200 mg/Nm^3, but Enel agreed with Italian local authorities to reduce NOx emissions under 100 mg/Nm^3. And the coal fired units emissions are referred to a 6% O_2 content in the flue gas on dry basis.

4.2 Sulphur Dioxide Emissions

SO2 gas turbines emissions are not measured in the gas turbine exhaust gas, but often natural gas holds sulphur compounds.
With reference to coal fired power plants EU standards request SO_2 emissions lower of 200 mg/Nm3, but Enel agreed with Italian local authorities to reduce SO_2 emissions under 100 mg/Nm^3.

4.3 Carbon Monoxide and Carbon Dioxide Emissions

Combined cycle CO emissions are ranging from 15 to 20 mg/Nm3, while the CO emissions of conventional units are negligible. But US Authorities impose to reduce CO emissions of large combined cycles at 1 ppm using catalyst.
CO_2 is not a pollutant, but has an impact on the greenhouse gases.
CO_2 emissions are tied to the efficiency of the power plant and are respectively about 0,38 t/MWh for new combined cycles and about 0,80 t/MWh for conventional advanced coal fired units.

4.4 Particulate Emissions

Also particulate emissions are not usually measured in gas turbine exhaust gases, but recent investigations confirm that gas turbines exhaust gases can hold PM10, PM5 and PM2,5 mainly during plant start up and low load.
When the gas turbine operates at high load and in steady state conditions, the combustion process, specifically DLN, is highly efficient and therefore usually do not produce PM emissions.
In effect, gas turbines and combined cycles exhaust gases may hold particulates coming from:

- inert solids within fuel gas supply; usually, but not always gas turbines manufacturers impose to filter natural gas at plant battery limits ;
- metallic rust and oxidation products (present also in the gas transportation piping, in the cc inlet and exhaust equipment including the heat recovery steam generator). It is important to note that gas travel for

	Combined cycles:	Combined cycles:	Coal fired unit:	Coal fired unit:
	Pollutant content mg/Scu-meter @ 15% O2 v/v dry, during premixing (from 50% to 100% load)	Pollutant content mg/Scu-meter related @ 3.5% O2 v/v dry, during premixing (from 50% to 100% load)	Pollutant content mg/Scu-meter @ 3.5% O2 v/v dry, also at low loads	Pollutant content mg/Scu-meter @ 6% O2 v/v dry, also at low loads
NOx	25	73	118 or lower	100 or lower
SOx	perhaps negligible, but not measured in Italy	perhaps negligible, but not measured in Italy	118 or lower	100 or lower
Particulates	not measured in Italy	not measured in Italy	15	15
CO	20	58	Negligible	Negligible

Table 5 : Combined cycle emissions in respect to the coal fire unit emissions in Europe

thousand kilo-meters inside not previously cleaned steel piping ;

- formation of aromatic compounds or PM10, PM5 & PM2,5 during natural gas combustion, due to poor premixing during DLN combustion and/or oxygen scarcity at low loads in some combustor zone or due also to the heavier molecules existing in the gas [5].

4.5 Comparison

Table 5 is comparing the combined cycle emissions in respect to the coal fire unit emissions. Gas turbines manufacturers usually obtain the above indicated guaranteed emissions at steady state loads from 50% to 100% and if the combustors are well adjusted.

The reduction of NOx is obtained also to the detriment of an increase of CO emissions.

As indicated in this table 5 it is important to note the NOx gas turbine emissions are referred to a 15% O2 content, while the standard emissions of a conventional power plant are referred to a 6% O2 content, but in effect the O2 content is around 3.5%.

In this table 5 both the cc and the conventional units emissions are also referred at a 3.5% O2 content.

In addition, basing on the fact that the flue exhaust gas temperatures at chimney outlet are ranging from 95 °C to 100 °C for cc and from 120 °C to 125 °C for conventional units, the upward lift of the cc flue exhaust gas is lower and so the pollutants emitted by the cc may be discharged nearby the plant mainly in case of thermal inversion.

This comparison between coal and natural gas on environmental basis must take also in due consideration their emissions during their extraction, mining, treatment and transportation steps up to the power plant (upstream emissions) [8].

A comparison between coal and gas upstream emissions is not easy on quantitative basis, because it is dependent from the coal mining and gas well locations and characteristics, from the type of used transportation system and from the length of journey from the fuel source to the power plant.

4.6 Main Emissions During the Upstream of the Natural Gas Life Cycle

In the case of natural gas we must take in due consideration mainly:

- gas flaring (gas combustion on the well area) and venting (release of gas to atmosphere also on the well area), referred to the gas that cannot be used locally or transported. During the World Bank-IMF Spring meetings to tackle issues such as the impact of climate change and the efficient use of clean energy, the Global Gas Flaring Reduction partnership issued a statement April 23, 2006 estimating that over 150 bcm of natural gas are being flared and vented annually. That is the equivalent of the combined annual gas consumption of Germany and France. And the 40 bcm of gas flared in Africa is equivalent to half of the continent's power consumption;
- gas purification near the extraction area to reduce CO2 (that can reach also from 20% up to 30% in volume) and H2S content. These CO2 and H2S are usually vented to atmosphere;
- gas leakages during its transportation and CO2 emitted by the gas turbines moving the pipeline gas compressors and by the LNG ships motors.

4.7 Main Emissions During the Upstream of the Coal Life Cycle

In the case of coal we must take in due consideration mainly:

- natural gas (including in some cases up to 90% of methane) leakages from the coal mining during coal extraction: this gas, that must be

removed during coal extraction mainly for safety reasons, is or flared or vented or conveyed through pipelines to the natural gas users (power generation, home heating etc). This gas coming from coal-bed formations is including a 2 micron coal dust (mean particle size) that quickly coats gas filters, and it is tough to remove when it builds up in dehydration, processing, and lubricating liquids;
- dust formation from coal during its transportation and storage : but now are used covered geodesic domes for storing coal and coal is transported for example from the ships to the boiler coal bunkers through a fully closed belt conveyor system, so dust dispersion to the environment is approaching to zero;
- wastewater discharges: the cleaning of all coal handling machinery is usually made using water that after its use is conveyed to water purification systems.

4.8 Noise

Noise control, in its broadest sense, is the prevention of noise before it is generated. Alternatively, noise reduction is the attenuation of noise after it has been produced. Any moving machinery creates noise that can be reduced through the correct design of the machinery (mainly reducing the speed of the machinery components and of the inside involved fluids and solids). But the reduction of the noise produced by the machinery itself, increases its cost, so usually the project engineer is trying to finding a technical and economic compromise between the improvement of the design of the machine and the attenuation of excess sound through absorbent surfaces (usually soft materials) [11].
Basing on the fact that the number of machinery used within a coal plant is higher in respect to the machinery used in a combined cycle plant and that the land requirement of a coal plant is about 30 times the land requirement of a combined cycle plant, the noises generated by a coal plant exceed that of a cc plant.

5. Combined Cycle versus Supercritical Coal Fired Unit Emissions: in The Next Future

Being important EU electric utilities and petrochemical companies strongly interested to develop the CCS technologies within the ZEP in the next future the fossil fired power generation plant emissions will approach to almost zero.
Basing on the fact that the content of impurities within CO2 delivered to sequestration facilities must be reduced to very low values (preliminary studies indicate also 0,01%), the future emissions in case of the adoption of CCS post combustion technologies both for CC and conventional plants could be as follows.

5.1 Nitrogen Oxide and CO Emissions

Gas turbines would use also in Europe the 9 ppm combustion technologies now requested by the US Authorities and always referred to a 15% O2 content in the flue gas on dry basis. Additional reduction to about 3 ppm will be obtained through catalysts.
The NOx emissions of the coal fired units will be reduced to 20 ppm or lower as referred to a 6% O2 content in the flue gas on dry basis, combining at their best low NOx burners, BOFA (boosted overfire air), Selective autocatalytic reduction (SACR), NOx Selective Catalytic Reduction (SCR) [6].

5.2 Sulphur Dioxide Emissions

SO2 gas turbines emissions must be measured also in the gas turbine exhaust gas and in case of need actions (for example scrubbers) must be included to minimize these SO2 emissions.
The SOx emissions of the coal fired units must reduced in this case to 10 ppm as referred to a 6% O2 content in the flue gas on dry basis. Some manufacturers offer De-SOx systems including a second scrubber downstream of the first one.

5.3 Particulate Emissions

Natural gas supply station of the gas turbines will be equipped with filtering and/or scrubbing systems to minimize particulate emissions.
The particulate emissions of the coal fired units will be reduced also under 2 ppm or lower, with an additional scrubber or with a wet electrostatic precipitator (wesp).
As indicated at item 3, the oxy-fuel combustion technologies look presently foreseeable only for conventional plants. In this case the limits of the pollutants within the exhaust gases and the used technologies will be the same as in case of the post combustion with the following advantages:
- NOx arises only from the nitrogen contained in the coal;
- higher flame temperature decreases particulates;
- the reduction of the combustion gas flow rate reduces the dimension of the De-NOx, De-SOx and De-dust systems.

In the case of adoption of pre-combustion de-carbonization, the gas turbines combustors will be supplied by hydrogen and air and the NOx will be limited during combustion to about 10 ppm and further reduction looks not required.

6. Conclusions

We hope that the readers can find within this paper sufficient information for a preliminary survey of this important topic both from the point of view of the involved technologies and from the point of view of their impact on the environment.

With the existing technologies (item 5.0) the flue exhaust gas emissions of the conventional coal fired plants are approaching in Europe the emissions of the natural gas combined cycles.

On the contrary in US the emissions of combined cycles required by the local authorities are definitely lower in respect to the cc emissions required in Europe and so lower of the emissions of the US and EU conventional plants.

In the next future with the adoption of the CCS (carbon capture sequestration) technologies (item 6.0) in the framework of the ZEP (zero emission projects), the flue gas exhaust emissions of the conventional plants will be on the same level of the emissions of the combined cycles on world wide basis.

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