

# Oxyfuel Combustion Retrofits for Existing Power Stations

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## ABSTRACT

Oxyfuel combustion is one of the promising technologies to enable CCS for new and existing coal-fired power plants. For retrofit applications, oxyfuel is an attractive option because it does not have major impact on the boiler-turbine steam cycle.

This paper presents a case study for retrofitting oxyfuel combustion technology in large state-of-the-art power plants that are originally commissioned and operated in air-fired mode. The overall process design for the modified power plant is outlined; necessary modifications of relevant components are explained. It is shown that future CO<sub>2</sub> emission regulations can be met by retrofitting oxyfuel technology. The retrofit measures ensure that the power stations still can run under both air-fired and oxyfuel-fired conditions if required by regulations / market conditions. This provides additional operational and commercial benefits for the operator of the plant and reduces the technical risk of implementing new components and processes not yet proven in the power sector.

## INTRODUCTION

Coal-fired power plants with CO<sub>2</sub> capture and sequestration (CCS) are widely expected to be an important part of the future technology portfolio to achieve overall global CO<sub>2</sub> reductions required for stabilizing atmospheric CO<sub>2</sub> concentration and global warming. New coal-fired plants built in the coming years will need to be “capture ready” which means that they can be retrofitted with CCS technologies as these technologies become commercially available and still offer competitive cost of electricity compared to other means of power generation. Oxyfuel combustion is one of the promising technologies to enable CCS for new and existing coal-fired power plants. For retrofit applications, oxyfuel combustion is an attractive option because it does not affect the boiler-turbine steam cycle, and with proper design its impact on the boiler fire-side processes and auxiliary equipment can be minimized.

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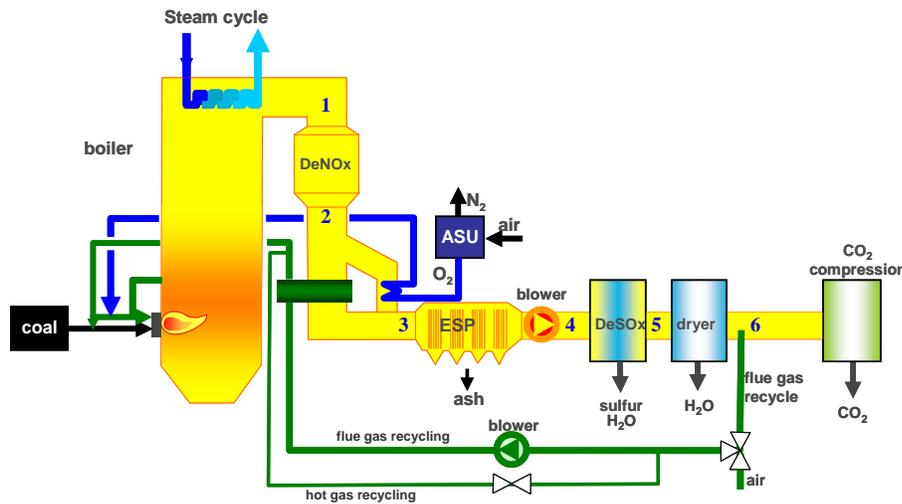
Oxyfuel combustion produces a flue gas stream containing mostly CO<sub>2</sub>, which can be directly compressed and purified without further treatment, assuming upstream removal of other pollut-

ants, such as SO<sub>2</sub>, NO<sub>x</sub> and dust. In the process shown in Figure 1 the CO<sub>2</sub> concentration in the flue gas is greatly increased by using a mixture of recirculated flue gas and pure oxygen instead of air for firing coal. Recirculation of flue gas is necessary to provide sufficient mass flow of gas for cooling the flame and also heat capacity and flue gas velocity for convective heat transfer in the boiler.

In the oxyfuel process CO<sub>2</sub> purity is mainly influenced by

- where the flue gas is recycled in the process (the cleaning that has been done up to this point) (possibilities: 1-6 according to Figure 1)
- the sealing of boiler and other components (the boiler is still operated at a pressure slightly below ambient pressure for safety reasons)
- the purity of the oxygen from the Air Separation Unit (ASU)
- the performance of all air quality control systems (DeNO<sub>x</sub>, DeSO<sub>x</sub>, and ESP)
- additional CO<sub>2</sub> purification during/after compression

Figure 1: The oxyfuel process



To ensure the value of actual investments in power stations and also maintain maximum flexibility for responses to future regulatory frameworks, it is necessary to prove that power stations constructed now can be retrofitted to oxyfuel firing and be operated as CO<sub>2</sub> lean power stations in future.

In the following sections, the plant modifications and new components required for retrofitting oxyfuel firing to an existing power station will be described along with the changes in firing and flue gas cleaning processes. A special characteristic of the retrofit measures is that the power station can be operated both with oxygen and air firing after the retrofit. As a result, the plant can be started and shut down in air-firing mode. Also in the event of operational trouble with the new systems, such as CO<sub>2</sub> compression, transport and storage, switching to air firing can be done quickly to ensure reliable electricity supply.

## ORIGINAL POWER STATION: DESIGN FOR AIR COMBUSTION

The retrofit measures will be explained based on a state-of-the-art 600°C (1112 °F), 820 MWe power station currently under construction; see Figure 2.

According to Figure 3, during air firing of the power station, the firing air is preheated in the flue gas air-preheater and distributed to mill (primary air), burner and overfire air (OFA) ports. A portion of the primary air enthalpy is used for feedwater preheat in the "mill air cooling cycle". This [1] increases the overall efficiency of the power station process by minimizing cold air to the mill to reduce exit temperature of the flue gas cycle. Additionally, less steam needs to be extracted from the turbine.

After combustion the flue gas is cooled in the air preheater, NO<sub>x</sub> concentration is decreased catalytically, dust is removed in the ESP and SO<sub>x</sub> is removed using limestone in a wet scrubber.

In the boiler the steam is mainly heated by radiation in the furnace and by convective heat transfer in superheaters, reheaters, and economizer in the convective pass.

Figure 2: Power station and design coal

820 MWe / 2088 t/h  
Once-through steam generator, Benson®  
Bituminous Coal

Design parameters:  
SH: 600 °C / 276 bar a  
RH: 620 °C / 51 bar a  
Commissioning: 2011/2012

Design coal:  
LHV: 25100 kJ/kg  
Ash: 13 %  
Water: 10 %

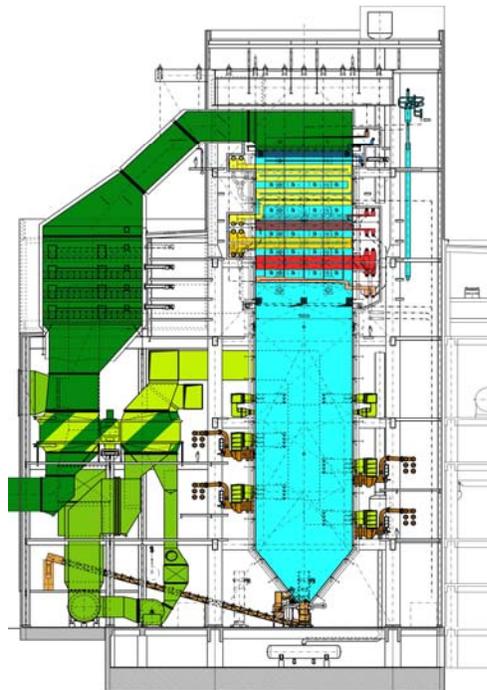
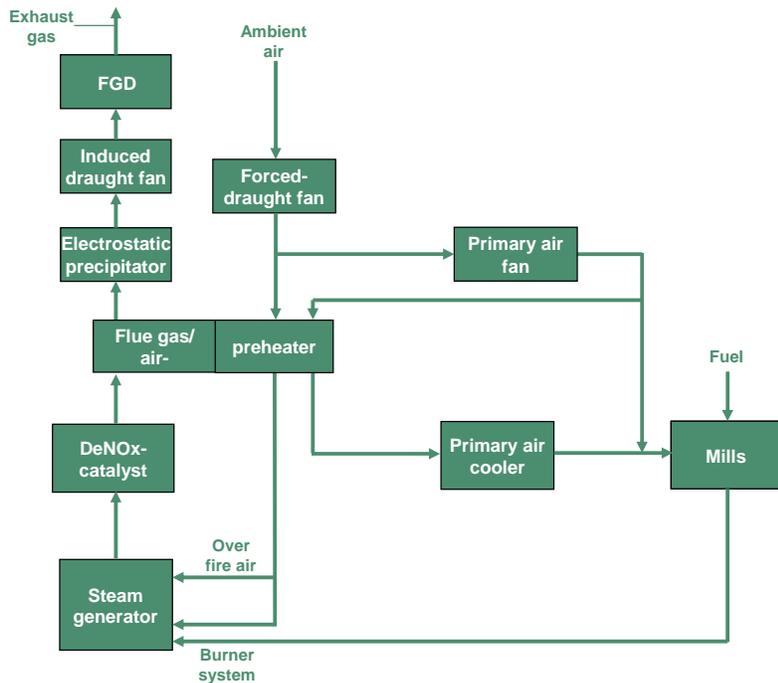


Figure 3: Firing process (air case)



## RETROFIT TO OXYFUEL FIRING

Looking at the different options for flue gas recirculation (locations 1-6, Figure 1) it is obvious that the complexity of flue gas recycling is reduced from the progress made in flue gas treatment. Recycling high-temperature flue gas (before air preheater) is thermodynamically advantageous but requires a total change of the heat balance and a re-design of the plant (boiler and components). A high dust recirculation upstream of the ESP would increase the erosion of all firing and boiler parts. Without DeSOx the  $\text{SO}_2/\text{SO}_3$  concentration would be increased by accumulation (~factor of 3) and additionally  $\text{SO}_3$  formation would increase from contacting with catalytic surfaces. Therefore all firing and boiler components (flue gas and recycle gas ducts, blowers, mill, burners, heat exchangers, boiler materials) would be at risk from corrosion.

For retrofit cases, the original plants are not designed on the air side for such an operation involving high temperature, dust or  $\text{SO}_2/\text{SO}_3$  concentrations. Modifications would be quite expensive since all equipments in the boiler house would have to be replaced.

For all of these reasons the retrofit concept shown below is based on the recirculation of cold, cleaned and partially dried flue gas after (improved) DeSOx and additional flue gas cooling. This would allow all existing components including blowers and ducts – at least inside the boiler house - to be used after the retrofit. The only measure to be taken inside is to preheat the recycled flue gas up to a temperature well above the saturation point so as to avoid condensation, by recirculating a small amount of hot flue gas.

Most of the necessary retrofit measures will be implemented outside the boiler house. Switching between oxyfuel and air operation mode can be done simply by using gas tight dampers at the former air inlet where the recycle duct is mounted.

Other changes outside the boiler house involve pure oxygen oxidation in the (improved) DeSOx plant, the addition of a flue gas cooler/condenser upstream of flue gas recycling and subsequent cleaning of the flue gas to reduce the SO<sub>2</sub>/SO<sub>3</sub> content still further. The purge gas of the mill is switched to CO<sub>2</sub>, the atomizing gas for the aqueous ammonia in the DeNOx is replaced by CO<sub>2</sub> and the ash removal at the ESP is replaced by a gas tight system. For oxygen preheating a tubular preheater parallel to the air preheater (now used as gas/gas preheater for the recycle gas) will be installed.

## Thermal Engineering and Combustion Technology

To prevent significant changes to the power plant heat balance, it must be assured that the heat transfer in furnace and heat exchangers in the convective pass match the original design. Additionally, the material temperatures have to be kept in a tolerable range and the steam temperatures and pressures should match the air combustion case. These requirements are fulfilled by the following variables in the oxyfuel case:

- Furnace exit gas temperature upper limit set by ash melting temperature
- Mass flow of recycled flue gas and split in gas for burner (primary gas and other), over-fire air and curtain gas
- Oxygen content in different gas flows

During the redesign under oxyfuel conditions the firing components (mill, burner) are recalculated as is the heat transfer in furnace and heat exchangers with respect to the changed flue gas properties so as to determine the optimal process parameters. For the retrofit case the modifications of existing components are minimized so as to reduce plant outage time.

### *Mills*

An important criterion for mill operation is the discharge of particles by flue gas. The dominating force is the flow resistance

$$F_{sw} = c_w \cdot A_s \cdot \frac{\rho_G \cdot w_G^2}{2} \quad \text{Eq.1}$$

with the drag coefficient  $c_w$ , the velocity  $w$  and the cross sectional area of the particle  $A$ . The drag coefficient  $c_w$  is a function of Particle-Reynolds number  $Re_p$

$$Re_p = \frac{\rho_G \cdot \Delta c \cdot d_p}{\eta_G} \quad \text{Eq.2}$$

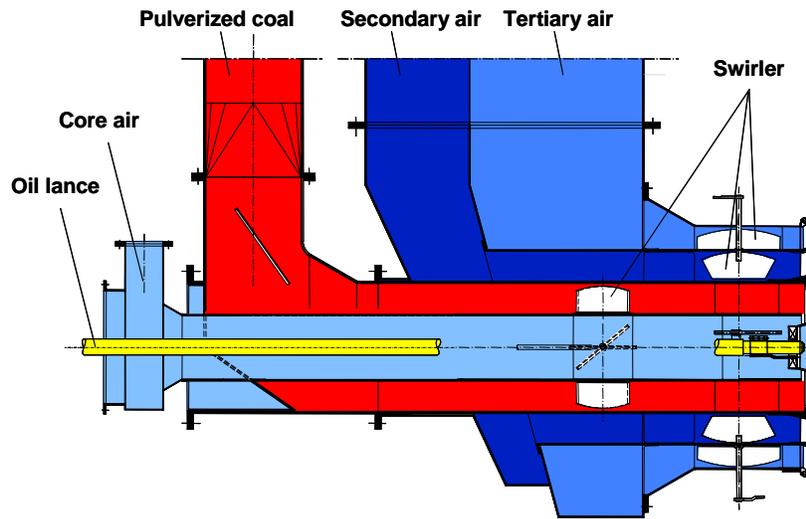
with the density of the flue gas  $\rho_G$ , the difference of velocities of gas and particle  $\Delta c$ , the diameter  $d_p$  of the particle and the dynamic viscosity  $\eta_G$  of the gas. As a result, the force of flow resistance depends on temperature and composition of the carrier gas and therefore the massflow required for the transport of the fuel particles depends on location. The calculations proving that the gas can carry the fuel particles have to be carried out at least at the mill nozzle ring, upstream and downstream of the classifier and in the ducts. The volumetric flow has to be the same as for

air firing operation to get a reliable and steady flow downstream of the classifier. The lower velocity at the nozzle ring in this case is compensated by the higher gas density.

### ***Burner***

The power station studied here uses Hitachi Power Europe's low NOx DS burners (Figure 4) [2].

Figure 4: Low NOx DS burner



Except for the primary gas flow, which has to be adjusted to the mills' needs, the momentum gas flows at the burner are kept constant in the retrofit case so as to get a flame shape similar to that in the atmospheric mode.

The momentum flow is

$$\dot{I}_{PG,SG} = \dot{m}_{PG,SG} \cdot w_{PG,SG} \quad \text{Eq.3}$$

with

- $\dot{I}_{PG,SG}$  momentum flow of primary and secondary gas
- $\dot{m}_{PG,SG}$  mass flow of primary and secondary gas
- $w_{PG,SG}$  flow velocity of primary and secondary gas.

With unchanged cross section and the continuity equation, Eq.3 results in

$$\dot{m}_{PG,SG} = \dot{m}_{PL,SL} \cdot \sqrt{\frac{\rho_{PG,SG}}{\rho_{PL,SL}}} \quad \text{Eq.4}$$

with

- $\dot{m}_{PG,SG}$  mass flow of primary and secondary gas in oxyfuel case
- $\dot{m}_{PL,SL}$  mass flow of primary and secondary air in atmospheric case
- $\rho_{PL,SL}$  density of primary and secondary air
- $\rho_{PG,SG}$  density of primary and secondary gas

The flame temperature and burnout progress are adjusted to fulfil the needs of heat transfer utilizing the oxygen concentration as a variable. This is demonstrated by the findings from a rotational symmetric flame calculation.

Figure 5: Temperature distribution in °C

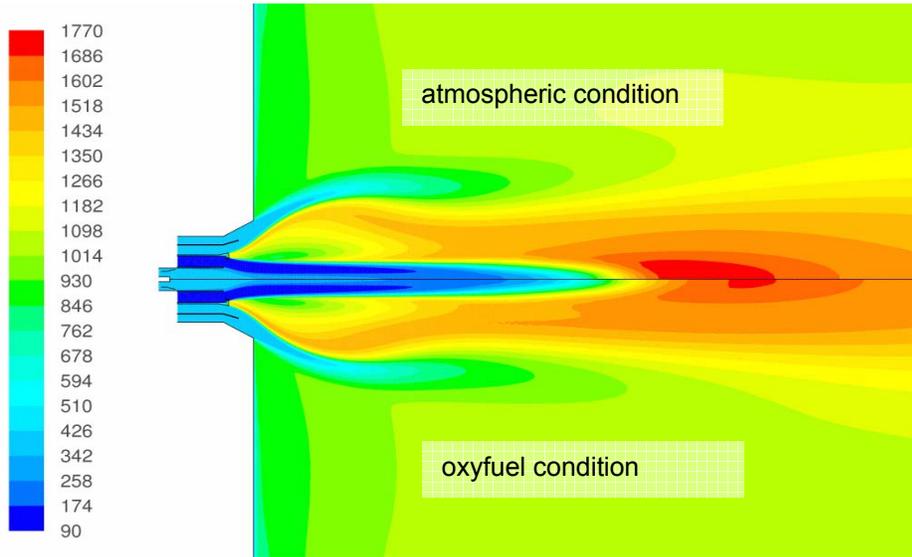


Figure 5 depicts the difference between the temperature distribution of atmospheric and oxyfuel-fired flames. Whereas the upper half shows the temperature distribution of the atmospheric flame, the lower half reveals the findings for oxyfuel conditions. The difference is very small under the examined conditions. This shows that the chosen parameters for the oxyfuel case are appropriate for getting firing conditions inside the furnace similar to those under atmospheric conditions.

It should be pointed out that the flame temperature is very much affected by the volume fraction of the oxygen in the oxygen carrying gas. The volume fraction is shown in Figure 6. Here the oxygen concentration is chosen to match temperature distributions of air and oxyfuel firing as shown in Figure 5. The often discussed decrease of oxyfuel flame temperature is countered by increasing the volume fraction of oxygen in the oxygen carrier gas.

Comparison of the axial velocities (see Figure 7) shows that the rule for the momentum for the oxyfuel conditions really does result in similar flow fields for atmospheric and oxyfuel flames. In this figure, the white zones represent backflows. The backflow zone behind the tooth-ring of the primary air tube has nearly the same shape in both the atmospheric and oxyfuel modes. This backflow zone is essential for burner ignition purposes.

The furnace exit gas temperature is similar to that in the air combustion case. Since NO<sub>x</sub> formation is reduced during oxyfuel combustion due to the absence of nitrogen in the combustion gas, the burner air ratio is increased.

Figure 6: Volume fraction of oxygen

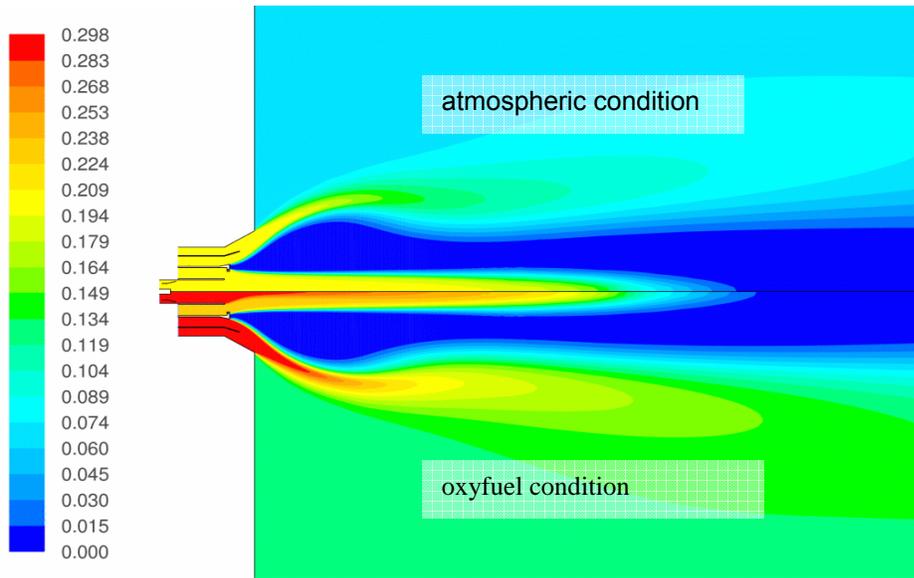
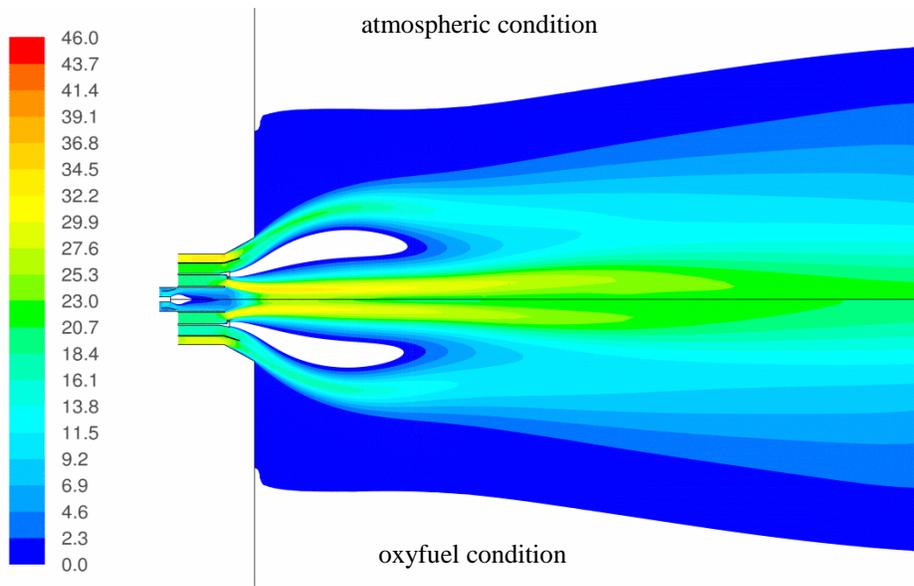


Figure 7: Axial velocities



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### ***Overfire Air/Gas***

The mass flow of gas in the OFA system is adjusted so that the heat transfer in the convective pass matches the values of the original design.

As is shown in Table 1 the flue gas density in oxyfuel firing is increased by 35%, the heat transfer coefficients for convective and radiative heat transfer by 2.7 and 38.3% respectively and the flue gas mass flow by 3.9%. These increases are partially compensated by a 17K or 5.2% de-



## ***Mill***

The purge gas air used to protect the mill's rotating parts is replaced by CO<sub>2</sub> in the retrofit case. A special sealing system ensures that no CO<sub>2</sub> enters the boilerhouse.

## ***Regenerative Air Preheater***

As Figure 1 shows the air preheater is also needed in oxyfuel firing to preheat the recycled flue gas. This gas cannot consume all the heat due to the absence of the mass of oxygen. Additionally, the oxygen cannot be mixed with the flue gas upstream of the air preheater due to leakage inside the air preheater – something which would increase the oxygen (and energy) demand by losses to the hot flue gas side and also reduce CO<sub>2</sub> purity.

## ***Oxygen Preheating***

As a consequence, a tubular heat exchanger is installed in a bypass to the air preheater to heat the oxygen. The oxygen preheater is located in a bypass duct parallel to the existing air preheater (gas/gas heater) so that duct length is minimized. The inlet/outlet flue gas ducts are equipped with dampers for shutoff and control of the gas flow. By total shutoff of the oxygen preheater, air firing can be enabled even after the retrofit.

The flue gas leaving the oxygen preheater is remixed with the main flue gas duct downstream of the ESP. The area required for the O<sub>2</sub> preheater is about 250 m<sup>2</sup>, the volume is approx. 5000 m<sup>3</sup>.

## ***Oxygen Ducts In The Boiler House***

Downstream of the oxygen preheater the oxygen is divided into the streams to different mixing points with recycled flue gas. Mixing with the primary gas is done downstream of the regenerative gas/gas heater (originally air preheater) but upstream of the mill gas heat exchanger. The O<sub>2</sub> mass flow to the secondary gas and over-fire gas is split into two ducts leading to mixing points on the left and right side of the boiler. Each duct is equipped with measurement points for volumetric flow rate and control dampers. At the mixing points static mixers are mounted in the ducts.

## ***Ash Removal***

A retrofit is not necessary since a minimum ingress of air is already ensured by a wet ash removal system for the boiler which was implemented during the air firing design

## ***DeNO<sub>x</sub> (SCR)***

The air used for spraying anhydrous or aqueous ammonia into the flue gas in the DeNO<sub>x</sub> system is replaced by heated carbon dioxide (from the third or fourth level of the final carbon dioxide compression) so as to decrease the oxygen and nitrogen concentration in the flue gas.

## ***Electrostatic Precipitator***

Changes in the flow characteristics of ESP are not expected because turbulences in the range of the changing Reynolds numbers are comparable. Lower total flue gas volume flow of oxyfuel operation results in longer precipitator treatment time which favors improved dust collection.

On the other hand, lower peak burning temperatures can result in the ash composition and sizing, depending on coal types, being somewhat different [3]. This may have an impact on the ash resistivity and the collection efficiency of fine and ultra-fine fractions of the flyash.

However, a limited change in precipitator performance is not critical for modern units with a full air quality control system. This is because FGD and even the flue gas cooler are effective in capturing dusts. Overall, dust removal is adequate for flue gas recirculation and carbon dioxide compression.

Air leakages at the electrostatic precipitator have to be avoided. This is possible by replacing ash discharge units with air-tight comparable units. Air-tight rotary feeders or double flap valves will be used to avoid leakage of pneumatic conveying air to the electrostatic precipitator. To prevent any back leakage of pneumatic air, the discharge units are to be provided with a small amount of sealing carbon dioxide.

### ***Preheating Recycled Flue Gas***

Preheating the recycled flue gas is done by recirculating a small amount of hot, clean flue gas so as to raise the flue gas temperature significantly above the saturation point and thus avoid condensation. This, and the improved DeSO<sub>x</sub> described below, will stop corrosion in the ducts and on all existing components.

### ***DeSO<sub>x</sub> (FGD)***

State-of-the-art desulfurization units are open-spray tower absorbers with limestone as reagent. For oxidation of the calcium sulfite to calcium sulfate, air is blown to the absorber sump directly in front of the agitators.

In the oxyfuel process, all reactions within the absorber have to work under a carbon dioxide atmosphere. As already shown on a laboratory scale the desulfurization performance is lowered under oxyfuel conditions [4] when scrubbing is done with limestone. This effect is probably even more marked under real conditions because limestone solubility is hindered by the carbon dioxide atmosphere in the absorber. Saturation of the slurry with carbon dioxide will see the solubility of limestone drop significantly. For this reason the reagent should be changed to calcium oxide (quicklime), which does not need to release carbon dioxide to the flue gas while dissolving.

At least the same performance is expected from running the absorber with calcium oxide under oxyfuel conditions as it is from running the absorber with limestone under normal conditions. Using quicklime under normal conditions, experience shows that a lower recirculation amount is necessary for the same absorber efficiency.

To oxidize the calcium sulfite to calcium sulfate in the absorber sump, gaseous oxygen produced in the air separation unit replaces the existing oxidation air in the oxyfuel process desulfurization unit. In new power plants, external oxidation of the sulfite in a separate tank might be favored, but in retrofitting a plant this will be hard to handle due to the absorber piping and recirculation pump arrangement.

The conclusion is to change the absorbent mixing station from limestone to lime which only needs an additional slaking system. Furthermore, the absorber oxidation air system should be changed to use pure oxygen, necessitating a retrofit of the oxidation blowers and agitator system.

### ***Flue Gas Drying Cooler***

In the described oxyfuel process the flue gas must be dried before being recirculated or compressed. This entails cooling down the flue gas to 30°C as a saturated flue gas. The required cooling duty is approximately 150 MW(th) for a 820 MWe power plant.

There are two alternatives for this cooling. One can use a closed spray cooling absorber, or an indirect heat exchanger. The closed spray cooling absorber can be used to deliver sodium hydroxide for additional flue gas cleaning. Both cooling types are technically possible solutions; the choice will be made based on detailed site-specific evaluations.

In the cooler, approximately 190 m<sup>3</sup>/hr of condensate is produced for an 820 MWe unit. A part of this condensate can be used as makeup water for the FGD absorber.

Due to the large amount of condensate the cooler also contributes to flue gas cleaning. Nevertheless, flue gas ducts for recirculation and ducts to the carbon dioxide compression stage should all be made corrosion-resistant (i.e. FRP material).

### ***Recirculation Duct And Link To Oxygen System***

Downstream of the dryer the flue gas is split and one flow is directed to the boiler house. The duct is connected to the outside air inlet with leak-tight dampers which also provides air in the case of air firing. A small proportion of the already preheated recirculated flue gas is used to pre-heat the main stream of the recirculation to a temperature above the dew point before entering the existing ductwork. The hot gas duct (internal recirculation) is connected to the flue gas duct downstream of the gas/gas preheater. Both the hot gas duct and recirculation duct are equipped with control dampers and measurement points for volumetric flow rate.

### ***Carbon Dioxide Purification And Compression***

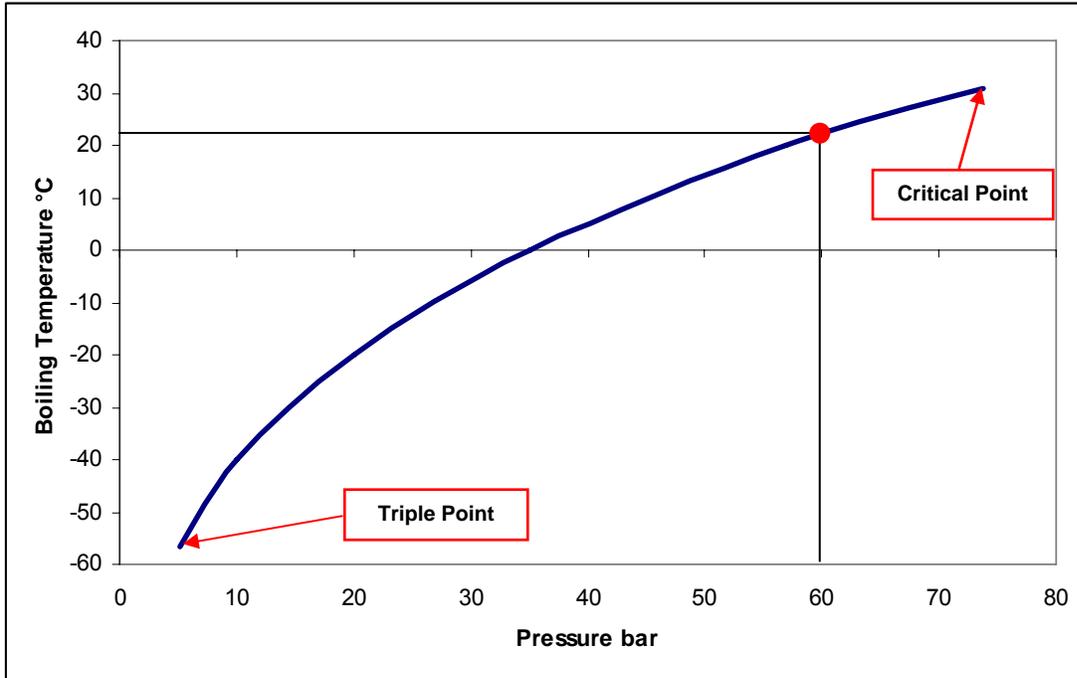
In the oxyfuel mode the flue gas contains about 93 %wt of carbon dioxide. The mass flow is reduced to 25 % of flue gas flow leaving an air-fired furnace. Purification and compression of this CO<sub>2</sub> rich flue gas is the last step of the oxyfuel process. This plant is divided into 3 to 4 compression units.

Some of the remaining contamination gases, such as NO<sub>x</sub> and SO<sub>x</sub>, are separated during compression of the flue gas and leave the process as condensate from the intermediate coolers as sulfuric and nitric acids. Most of the water is also removed from these intermediate coolers. There is no other purification step; the other trace gases such as nitrogen, oxygen and argon remain in the compression stream.

To also remove these gases, liquefaction of the carbon dioxide is necessary to make a phase separation possible. This process, as shown in Figure 9, is to be done just below the critical point of the carbon dioxide to avoid low temperatures for liquefaction.

Whether this is necessary or not is decided by the requirements of transport and later storage of the carbon dioxide. For enhanced oil or gas recovery, no oxygen in the gas is wanted. For other storage alternatives such as deep aquifers no oxygen limits have as yet been set up. Research on this has not been concluded. In fact it has only started in most countries.

Figure 9: Boiling temperature vs. pressure for CO<sub>2</sub> [5]



As long as their concentration is kept low, the trace gases of nitrogen and argon do not hinder carbon dioxide storage or use for enhanced oil and gas recovery. Water has to be removed down to very low values to prevent corrosion in pipelines and tanks.

### ***Air Separation Unit (ASU)***

The only commercially available and proven technology to supply an 820 MWe bituminous coal fired power plant from today's perspective is the cryogenic process.

The 820 MWe power plant will require up to 13,500 t/d (including 10% reserve) of oxygen. The largest ASU to date is of 3,600 t/d. ASUs with capacities up to 4,800 t/d are currently being planned. This will make a number of ASU lines necessary. Furthermore the number of ASU-lines depends on the control range of each unit to cover the whole load range of a power plant.

For the 820 MWe gross power station the ASU has to be designed with 4 lines. The different modules are connected by an O<sub>2</sub> output manifold. Each line connected to the manifold is equipped with shutoff dampers to isolate the individual lines from the plant. This reduces the energy requirement for the ASU at partial load, and also allows each line to be serviced independently. From the manifold the O<sub>2</sub> is routed to the O<sub>2</sub> preheater. The space required for this plant is roughly 2.6 hectares.

An important issue is the load change rate of an ASU. A typical rate is 1%/min but the rate of a power plant, depending on the "grid code", is up to 5%/min. To compensate for this difference, a temporary buffer storage is necessary.

Another major issue is the energy demand of an ASU. Oxygen-purity and the pressure at the interface are the vital factors here. With consideration given to the carbon capture part, the best point of balance is achieved at higher oxygen purity. A typical specific energy consumption by leading manufacturers is 0.35 kWh/Nm<sup>3</sup>; for an optimized plant a value of 0.3 kWh/Nm<sup>3</sup> is reported. (All values refer to oxygen with ambient temperature and only slight overpressure). This results in 137MW and 117MW including 10% reserve.

## SUMMARY

The process engineering for retrofitting a power plant to oxyfuel firing to enable CO<sub>2</sub> capture after the combustion process is described in this paper. The flue gas composition for normal air firing and oxyfuel firing is shown in Table 2. The concentration of CO<sub>2</sub> in the flue gas after cooling is nearly 95 wt% (db.) in the case of oxyfuel firing. This gas can be directly compressed and directed to the storage site without further purification.

The required area for the new components as well as the demand for electrical energy and cooling capacity is shown in Table 3. The required area for AQCS modification is rather small compared to the ASU which has to be installed as new. Nevertheless, the ASU can also be constructed at some distance from the power station when the oxygen is transported to the boiler-house by pipeline. Hence, there is normally enough space for the remaining modifications on the site. The arrangement of the new components and plant modifications is shown in Figure 10.

Table 3 also provides the energy requirements for a number of modifications. The ASU and compressors require a large amount of electrical energy. Using the numbers given, the gross electrical output of the power plant in the worst case is reduced by more than 24%.

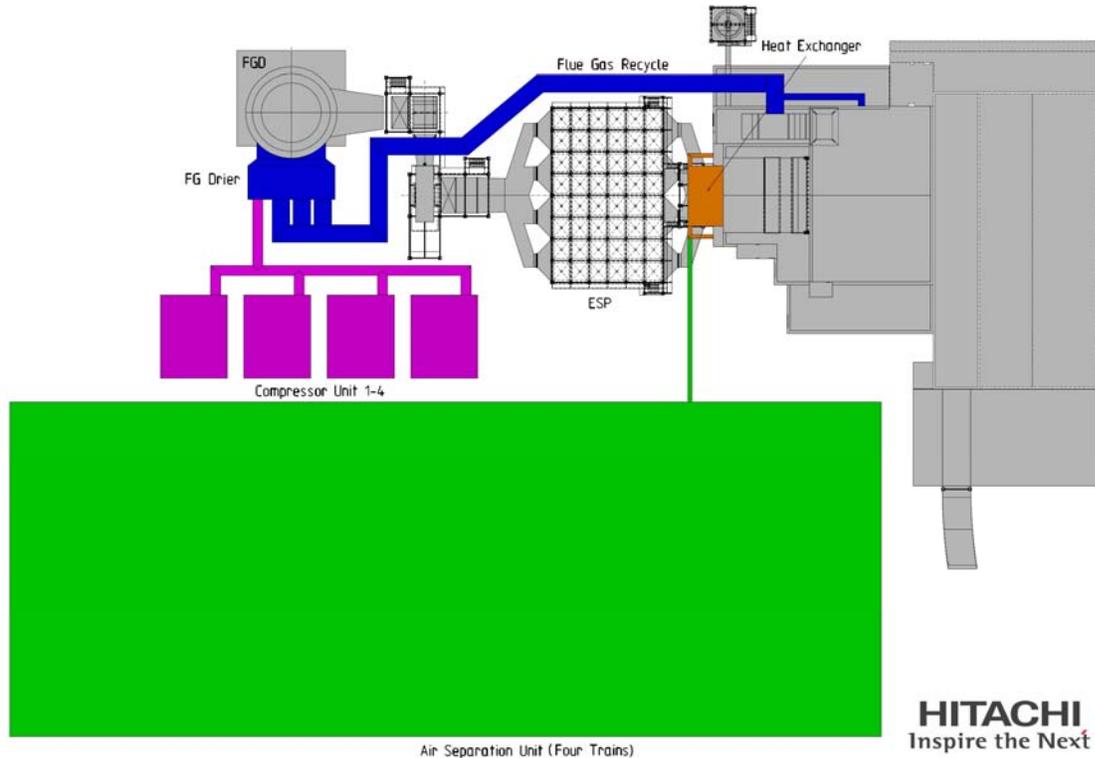
Table 2: Comparison of flue gas composition

gas species	air firing (Composition after ESP)		oxyfuel-firing (Composition after cooling)	
	wt % wet	wt % dry	wt % wet	wt % dry
H <sub>2</sub> O	5.9	-	4.8	-
CO <sub>2</sub>	19.4	20.6	89.9	94.9
N <sub>2</sub>	68.7	73.1	2.0	2.1
O <sub>2</sub>	4.5	4.7	2.9	3.0

Table 3: Demand of electricity, cooling duty and area for retrofit.

	area required [m <sup>2</sup> ]	P <sub>el</sub> [MW]	Q <sub>th</sub> (cooling) [MW]
ASU	26000	107	117
Cooling & AQCS modifications	900	4	150
CO <sub>2</sub> Compression	2000	85	

Figure 10: Arrangement for retrofitted power station



In conclusion, existing state-of-the-art coal-fired power stations can be converted to oxyfuel combustion with no change to the plant water-steam cycle and minimal modifications to the boiler house. Limited alterations to the air quality control system are needed. Major equipment additions for the air separation and CO<sub>2</sub> compression and handling are necessary. The converted power plant will have the flexibility to operate in both air-fired and oxyfuel modes.

While it has been shown that retrofitting existing power plants is technically feasible, all processes have to be further optimized in future to reduce the cost and efficiency penalty of CCS. Hitachi is currently undertaking extensive development work to improve basic technologies for oxyfuel combustion and other CCS options. This is being done so as to supply highly efficient, overall solutions for CO<sub>2</sub> lean fossil fuel power stations to the global market as a contribution to society by combating climate change.

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