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Oxy-Coal is Ready for Demonstration

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Babcock & Wilcox Power Generation Group, Inc. (B&W PGG) and Air Liquide (AL) have been developing oxy-coal technology with pulverized coal (PC) combustion for over ten years and it is now ready for demonstration. Oxy-coal combustion can be applied to new greenfield plants or retrofit to the more modern plants in the existing fleet providing over 90% CO_2 capture. Lower capture options also exist at lower capital cost and high operating efficiency.

AL and B&W PGG have made major advancements in oxy-combustion and are one of the current world leaders in this field. Together, B&W PGG and AL performed pilot-scale oxy-coal combustion tests on a 1.5 MWth pulverized coal (PC) fired boiler. Several economic and performance studies of oxy-coal PC power plants from retrofit to full-scale 550MWe net greenfield applications have been completed, including a major study with the U.S. Department of Energy (DOE) which showed oxy-coal to have a lower cost of electricity compared to their Integrated Gasification Combined Cycle (IGCC) or post-combustion (PCC) studies.

B&W PGG also modified its existing 30 MWth (100 MBtu/h input) Clean Environment Development Facility (CEDF) adding oxy-firing capability in 2007 and in late 2007 and early 2008, testing with bituminous, sub-bituminous, and lignite coals was completed with the cold recycle process configuration. Further testing was completed in 2008 with the warm recycle process. Extensive study of several process configurations and integration possibilities was also undertaken in 2008 to arrive at our current design.

During 2008 and 2009 two proposals were submitted to the DOE to demonstrate oxy-coal, but were not selected. In fact, in spite of its potential to be the lowest cost option, the DOE currently has no oxy-coal projects in their portfolio. As a result of our extensive development efforts, B&W PGG and AL are ready for commercial demonstration at about 100 MWe net scale with near zero emissions power (NZEP) and zero liquid discharge (ZLD) firing sub-bituminous coal.

A commercial reference plant capable of providing about 520 MWe is also being designed. This plant is based on sub-bituminous coal and incorporates the latest design features and integration concepts to produce the highest net efficiency at the lowest cost. Like the demonstration plant design, it has a low fresh water requirement and is NZEP and ZLD.

This paper briefly describes the work leading up to the current state-of-the-art as well as presenting the demonstration and commercial reference plant designs.

Introduction

According to the International Energy Agency's World Energy Outlook 2009, the global sources of electricity shown by fuel in 2007 are given in the left pie chart in Figure 1. The right chart shows their prediction of deployment in 2030. Comparing these charts, two things are notable: 1) total global electricity generation will increase by over 70% in the next two decades - so the electricity market is certainly not shrinking, and 2) coal continues to play a major role in the future global energy picture.

Though a much larger share of non-carbon technologies is forecasted, it is clear that coal and coal with carbon capture and storage (CCS) will be a significant element in the portfolio. For coal combustion, three possibilities exist: IGCC, PCC, and oxy-coal combustion. Recent cost and performance information from IGCC projects in progress are less attractive than initially predicted and IGCC is losing its perceived advantage over oxy-coal and PCC technologies for CCS.

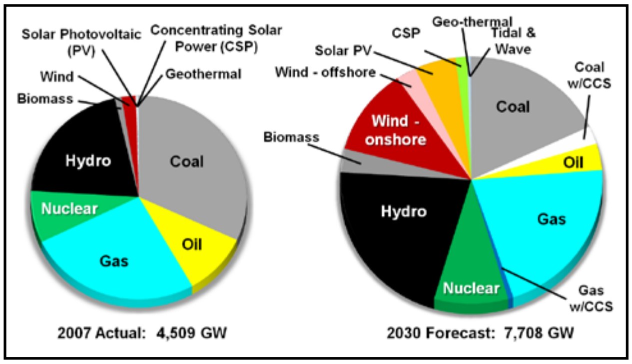

Fig. 1 Current and forecast electricity demand and sources.

More recently B&W PGG began developing PCC focusing on development of more effective solvents. In early March 2009 a strategic alliance with Fluor Corporation to market and sell their Econamine FG PlusSM carbon dioxide (CO_2) capture system for existing coal-fired power plants in the United States and Canada was announced. Econamine FG PlusSM is an advanced version of an established Fluor process that has been successfully used in 23 commercial plants for the recovery of CO_2 from flue gas for more than 20 years. Part of the alliance involves using B&W PGG's new test facilities to develop more cost effective solvents.

B&W PGG first explored oxy-combustion for Enhanced Oil Recovery in 1979 but with low oil prices it was not economical. In the mid 1990s, as interest in carbon dioxide emissions was increasing, interest in developing it for a means of concentrating CO_2 for storage or use was renewed. Since 1999 B&W PGG has been aggressively developing its potential and in 2001 AL joined the effort to incorporate air separation (ASU), and compression and purification (CPU) into the process and to jointly work to improve the overall efficiency and economics. This collaboration not only led to several engineering studies and cost estimates for both retrofit and greenfield applications, it included oxy testing at 1.5 MWth between 2001 and 2004 and large pilot-scale tests at 30 MWth in 2007-2008.

B &W PGG's 30 MWth test facility, shown in Figure 2, is a mini power plant with a specially designed boiler and a full complement of backend gas cleanup systems. Though it was "catch and release" in regard to CO_2, combustion and all of the other processes for gas cleaning were tested. This testing at the 30 MWth scale was the first in the world and bituminous, sub-bituminous and lignite coals were fired. Coal was successfully fed both indirectly for bituminous and directly from the pulverizer using recycled flue gas for the other two coals. Two process configurations were tested; cold recycle where all of the flue gas is cleaned and cooled to remove substantial moisture before recycling, and warm recycle where the secondary recycle is taken after the air heater and only particulate is removed. The testing confirmed control philosophy for transitioning as well as for all major trips. It showed 50 to 70% reduction in NO_x and provided SO_2, SO_3, Hg, and particulate removal data.

As a result of this success, a concerted effort was made in 2008 to determine the best process approach and explore optimization and integration of the power block, ASU and CPU components individually and as a whole. This work led to selection of the warm recycle process for low sulfur fuels and provided the direction needed for heat integration. Others have more recently done testing at 30 MWth and 40 MWth and though not as robust in coal and process variations, their results have provided further confirmation.

Meanwhile, AL has been developing ASU and CPU designs to reduce power consumption and cost. Figure 3 shows the gains so far and Figure 4 shows the evolution in just the past 3 years. These gains have been achieved by optimization of the design to oxy-coal requirements, ASU process improvements, and heat integration with the steam cycle.

Based on this work, a demonstration plant design was developed to generate 150 MWe gross and design of a commercial reference plant based on 700 MWe gross is in progress.

Benefits of oxy-coal

The key benefits of oxy-coal compared to the other options for CCS are higher efficiency, lower cost of electricity and most of all, the lowest air emissions and highest CO_2 removal. Before addressing these benefits, it should also be recognized that the plant uses commercially proven equipment and operates in the same manner as a conventional pulverized coal-fired plant. In addition, it offers flexible operation and load following and, if partial capture is desirable, the ASU can be designed and liquid storage can be provided so the plant can be operated for partial CO_2 capture now and additional removal capability added later. This reduces initial capital by as much as 25% of the total

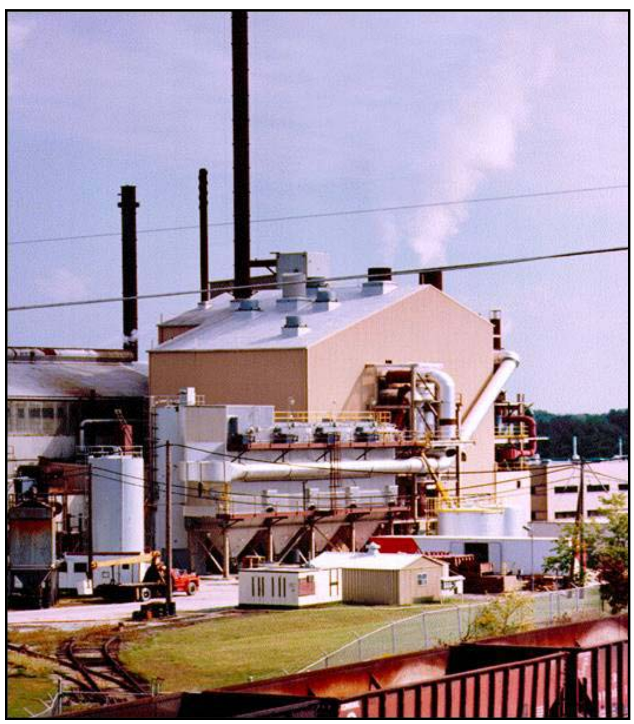

Fig. 2 B&W PGG's Clean Environment Development Facility (CEDF).

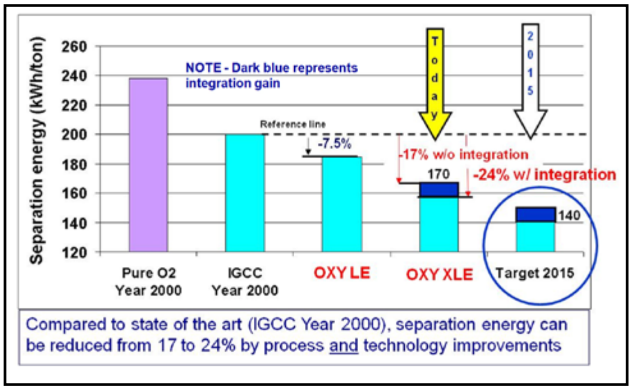

Fig. 3 Reductions in specific separation energy.

gas processing cost. If operated with air firing during peak hours when the electricity price is high and with oxy-firing during off-peak hours, revenues can be maximized and the impact on avoided cost of CO_2 is estimated to be 5% or less.

Oxy-coal is currently very competitive with non-carbon technologies including wind, solar and nuclear, and it leads the other options for coal. Unlike the other coal options, oxy-combustion produces lower CO_2 emissions and essentially zero air emissions of criteria pollutants and air toxics as shown in Figure 5.

Figure 6 was produced from the Department of Energy (DOE) reports noted at the bottom of the chart. It shows air fired technologies with the yellow background, conventional carbon capture technologies in the gray background and future carbon capture technology predictions with the green background. The technologies are identified along the bottom: Cases 3 and 4 are PCC with super and ultra supercritical steam conditions, Cases 5 and 6 are oxy-combustion with super and ultra supercritical steam conditions, and the two options circled in orange are the B&W PGG-AL warm recycle process with super and ultra supercritical steam conditions. Supercritical steam conditions are 3500 psi, 1110/1150F and ultra supercritical are 4000 psi, 1350F/1400F. Case 7 uses Ion Transport Membrane technology for oxygen separation. The average IGCC performance from a DOE study on the same basis is also shown.

Comparison of the B&W PGG - AL warm recycle design, circled in orange, to the other coal-based CCS technologies using DOE's own numbers shows noticeably higher efficiency. When ultra supercritical steam conditions become available in a decade or so, the efficiency will be comparable to a modern air-fired supercritical power plant today.

Figure 7 is configured the same as Figure 6 but it shows levelized cost of electricity (LCOE) and its breakdown. All cases are based on the same financial assumptions burning the same bituminous coal and estimated in 2007 dollars, not including owner's costs. Again, warm recycle promises much lower costs and future high temperature steam boilers will improve costs even more. As a point of reference, compare the Case 1 LCOE representing current conventional technology, with the Warm Recycle cases.

These studies show that oxy-coal can be expected to have an economic advantage over the other options for coal while providing higher net efficiency, the lowest air emissions, and higher CO_2 removal. Several IGCC and CC demonstrations are in progress in the U.S. and there are a couple of oxy-coal demonstrations just being initiated in Europe, made possible by government subsidy as well as an existing CO_2 value. But in spite of oxy-coal's benefits, no demonstrations are currently planned in the U.S.

This is primarily because oxy-coal has one disadvantage: it is an all-or-nothing technology. In other words, it cannot be applied to a slip stream because it involves the entire combustion process. This has implications for demonstration cost. For example, if 100 MWe is the right size to learn what is needed to scale up to 700 MWe commercially, either a small greenfield plant at full new plant cost must be built, or a small old existing plant with less than ideal site conditions must be retrofit, which is also expensive. This means higher capital investment without the benefit of economy of scale or higher steam conditions, and because the value of CO_2 and associated regulations are currently unknown, there is no certain means of recovering these costs making continued operation as a CCS plant following the demonstration uncertain. Conversely, PCC can be added to any existing plant using a slip stream of flue gas which makes the demonstration independent of the base plant size. This disadvantage has made funding an oxy-coal demonstration difficult.

Demonstration plant

Based on the success of development efforts and testing, a 150 MWe gross (100 MWe net) oxy-coal demonstration plant design was developed in 2009. If the commercial step is to be full scale, a demonstration of meaningful size, about 100 MWe net, is necessary. A unit much smaller would jeopardize scalability.

Figure 8 shows the major components: the boiler, dry scrubber, baghouses, moisture removal and sulfur polishing system labeled WFGD/DCC, as well as the ASU and CPU. The process is warm recycle where the secondary recycle, shown with green flues, has only particulate removed while the remainder of the flue gas, shown with blue flues, has SO_x, particulate, and moisture removed. The design includes a regenerative air heater with a special internal arrangement

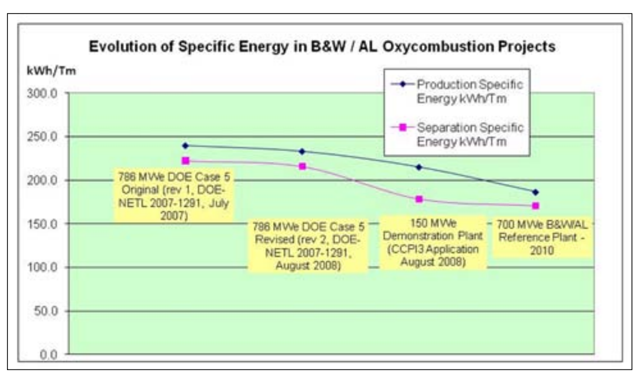

Fig. 4 Evolution of specific energy reductions.

	Air-Fired Plant	IGCC Plant (2) w/CCS	Oxy-Fuel Plant w/CCS	Air-Fired Plant	Oxy-Fuel Plant w/CCS
Fuel Type	Bituminous	Bituminous	Bituminous	Sub-bit	Sub-bit
Steam Conditions (PSI/F/F)	3600/1100/1100		3600/1100/1100	3600/1100/1100	3600/1100/1100
Plant Performance					
Gross MW	598	745	733	604	733
Net MW	550	556	550	550	550
Net Plant Heat Rate (Btu/kWh)	8662	10505	10143	9250	10831
Capacity Factor (%)	85%	80%	85%	85%	85%
Conventional Emissions (Expected)					
NOx (lb/MBtu)	0.06	0.0470	Note 1	0.06	Note 1
SOx (lb/MBtu)	0.04	0.010	Note 1	0.08	Note 1
Particulate (lb/MBtu)	0.015	0.007	Note 1	0.012	Note 1
Hg (lb/TBtu) (3)	0.784	0.571	Note 1	0.820	Note 1
CO2 Emissions (Expected)					
CO2 Removal Efficiency (%)	0	90.0%	92.5%	0	92.5%
CO2 Produced (Million Metric Tons/Year)	3.26	3.64	3.82	3.68	4.31
CO2 Captured (Million Metric Tons/Year)	0	3.28	3.53	0	3.99
CO2 Emitted (Million Metric Tons/Year)	3.26	0.36	0.29	3.68	0.32

1) Oxy emissions are below practical measurement limits
2) IGCC from GE IGCC system w/CO2 Capture per DOE/NETL-2007/1281 Report, Case 2
3) Air-fired emissions based on 90% removal expected

Fig. 5 Comparison of plant air emissions.

that eliminates any loss of oxygen to the CPU stream. The dehumidifier, labeled WFGD/DCC, is also designed to remove moisture while achieving some SO_2 polishing. The design makes full use of the water condensed from the flue gas in a manner that avoids water treatment and discharge and minimizes fresh water makeup.

Because it is only 150 MWe gross, the steam cycle is sub-critical at 2400 psi, and 1050F main and reheat steam temperatures. Designed for a location in Wyoming, it employs dry cooling with very low fresh water makeup, and is zero liquid discharge. Since the only air emissions in the oxy mode are from the CPU vent of non-condensables, they are very low. In addition to about 9% of the CO_2 produced and a small amount of argon and oxygen, NO_X emissions are expected to be below 0.003 lb/MBtu or about 13 tons/yr (does not include air startups), SO_X and particulate and mercury below typical power plant measurement accuracy, and CO, which is essentially unaffected by oxy-combustion, at about 780 tons/yr.

Commercial reference plant

Following a successful demonstration at 150 MWe gross, B&W PGG and AL expect to be prepared to sell a commercial-scale plant. In preparation, B&W PGG, Air Liquide, and URS Washington Group in Denver have been developing a reference design to generate 700 MWe gross. This effort includes preliminary design of all major components, performance and emissions predictions, system and plant arrangement drawings, a 3-D plant model, budgetary cost estimates and a preliminary plant financial analysis. It is designed for PRB coal with state-of-the-art supercritical boiler technology and steam conditions of 3500 psi and 1100F for main and reheat steam. The base case is at sea level with wet cooling. The impact of higher elevations and dry cooling will also be determined.

Our performance work and equipment sizing are nearly completed and we are on the verge of developing costs. As shown in Table 1, the preliminary net efficiency of 31.5% is not far from current fleet average without CCS and the air emissions are significantly below other coal-based options.

Table 1
700 MWe Gross Reference Plant

SPECIFICATION	AIR EMISSIONS
Coal: PRB, 8400 Btu/lb	**NO_X:** ≈ 52 tons/yr (not including startups)
Steam: 3500 psi, 1100F/1100F	**SOx:** below practical measurement
Gross Output: 703.6 MWe	**Hg:** below practical measurement
Net Output: 518 MWe	**Particulate:** below practical measurement
Heat Rate: 10,823 Btu/kWh	**CO:** 3128 tons/yr (without oxidation)
Net Efficiency: 31.5%	**CO_2 Emitted:** 443660 tons/yr
Wet Cooling	**CO_2 Stored:** 4456665 tons/yr (90% capture)
Sea Level	

Obstacles to deployment

Considering the success of efforts to date, oxy-coal is ready for demonstration, but there are obstacles not only to demonstration but for commercial deployment afterward. Some are technical misconceptions but most relate to financial viability, and storage.

The technical misconceptions are: a) the notion that oxy-coal is immature and won't be ready to demonstrate until a design with significantly reduced recycle is available, and b) that oxy-coal is not as suitable for retrofit to the existing fleet as PCC is believed to be, so it is not as attractive.

Low or No Recycle: It has been suggested that significant reduction in recycle means significant reduction in cost but it is not that simple. When coal is burned with nearly pure oxygen, the resulting combustion byproduct is primarily CO_2 with some water and other minor constituents. In addition, the quantity of combustion byproduct is also much smaller, about 25% of the amount of byproduct produced when using air. Figure 9 compares the compositions and flow quantities of the oxidant and combustion byproducts for air and oxygen combustion. Notice that because nitrogen has been removed from the combustion process, the concentration of constituents in the combustion byproduct is at least 4 times as high as with air firing.

In addition, firing coal with nearly pure oxygen significantly increases the flame temperature. To control flame temperature and dilute corrosive constituents in the combustion byproducts, a portion of the flue gas from the boiler is cleaned of undesirable constituents such as particulate, SO_2, SO_3, and water, and recycled to the boiler. Without recycle, the high concentrations of corrosive constituents

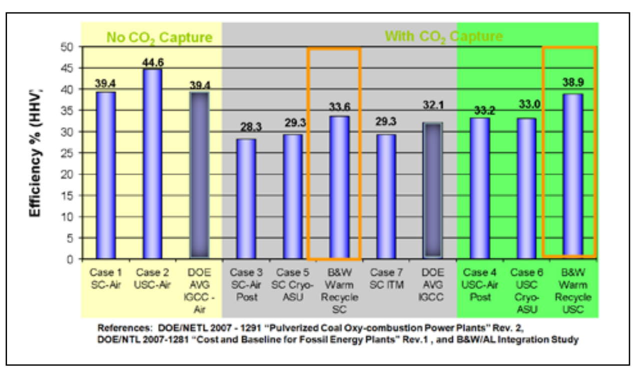

Fig. 6 Comparison of net plant efficiency.

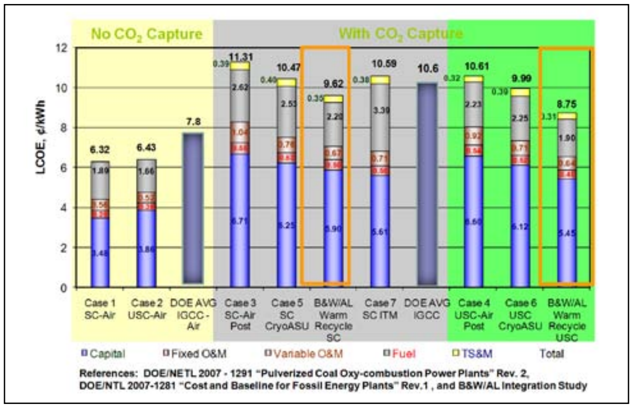

Fig. 7 Comparison of levelized cost of electricity.

coupled with the higher tube metal temperatures would exponentially increase corrosion rates and the much higher metal temperatures would require much higher grade and more expensive materials. The amount of recycle and the location in the process from which it is taken have been studied to determine what results in the lowest cost at the highest plant efficiency.

Current designs for pulverized coal generally recycle sufficient flue gas to produce about the same mass flow through the boiler as would be present with air firing. This quantity has been selected primarily due to material considerations in the boiler. Although some reduction in recycle and cost may be possible for pulverized coal systems with relatively low steam temperatures, low or no recycle is not practical and would deliver minimal, if any, cost savings for units with modern or advanced steam conditions.

In the boiler, the heat from combustion is transferred to water to generate high pressure, high temperature steam. The water and steam are contained in metal tubes and the heat is transferred to these tubes by radiation and convection. Radiation dominates within the furnace at higher gas temperatures but as the gas temperature decays, more heat gets transferred by convection than radiation until convection dominates in the convection pass. Due to the much higher heat fluxes in the furnace, water is used to cool the tubes with boiling occurring in the furnace. Steam is much less effective at cooling the tubes so superheating is normally done in the convection pass where heat fluxes are lower allowing use of available alloy materials in the high temperature outlet sections and reasonably cost-effective materials in the banks.

The amount of furnace heat transfer area (tubes) is set to absorb sufficient heat to limit the furnace exit gas temperature (FEGT) which is a function of the fuel. For coal it is limited to prevent slagging and fouling of the heat transfer surfaces. Since the total heat absorption in the boiler is established by the desired steam temperature and flow at the steam pressure, the FEGT defines the amount of heat absorption in the furnace versus the amount of heat absorption in the convection pass.

If recycle were significantly reduced, the flame temperature and burner zone heat release would drastically increase. In addition to furnace slagging concerns, this significantly increases radiation. Since radiation is a function of temperature to the fourth power, the gas temperature and tube metal temperatures increase significantly requiring higher alloys in the furnace. Higher alloys mean much higher material, fabrication, and installation costs. The higher gas temperature also results in less heat transfer surface required because of the greater log mean temperature difference. However, the furnace cost savings from decreased heat transfer surface is quickly overcome by the increased material associated costs.

If furnace absorption increases, convection pass absorption must decrease. And because the gas flow is much lower, a much smaller convection pass cross-section would be needed to maintain velocities that drive convective heat transfer. This means a longer convection pass with more tube bends. Again, though the quantity of surface decreases in proportion to the reduction in convection pass absorption, the total cost of the convection pass would not be reduced in proportion to the gas flow and may actually increase. Also important is the fact that decreasing convection is opposite of what is needed to achieve higher steam temperatures and steam cycle efficiencies. It has been shown that increasing rather than decreasing recycle (relative to air firing mass flow) is more beneficial to achieving ultra supercritical steam temperatures of 1300F or higher, even using the very latest materials like Inconel® 740 alloy. So decreasing recycle significantly would not reduce the boiler cost and it averts progress toward higher steam temperatures and efficiency.

Reducing recycle gas volume flow would reduce the cross-section of flues, scrubbers, ESPs and baghouses, but cost reduction would not be in proportion to the reduction in gas volume because 1) the cost of these systems is not primarily in the vessel or casing material, and 2) the performance and sizing of the gas cleaning systems is linked to the relationship between pollutant concentration and the gas volume flow.

Though the gas volume decreases as recycle is decreased, the same mass of pollutant, such as particulate or SO_2, must be treated. Because the quantity of ash does not change, the ash removal systems must have the same capacity and will be about the same cost. For the baghouse or ESP, the casing cross-section may be smaller but practical limitations on back-pulsing frequency and ESP retention

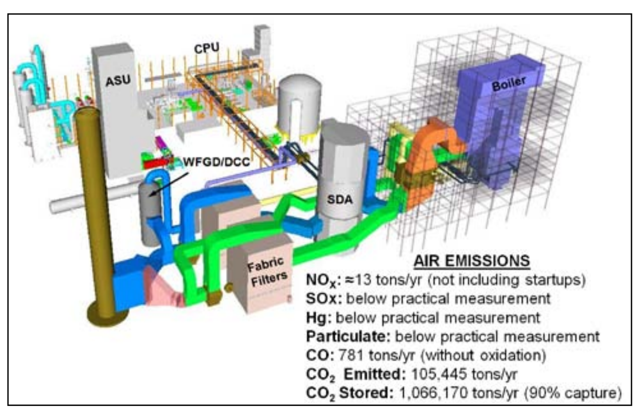

Fig. 8 150 MWe gross demonstration plant.

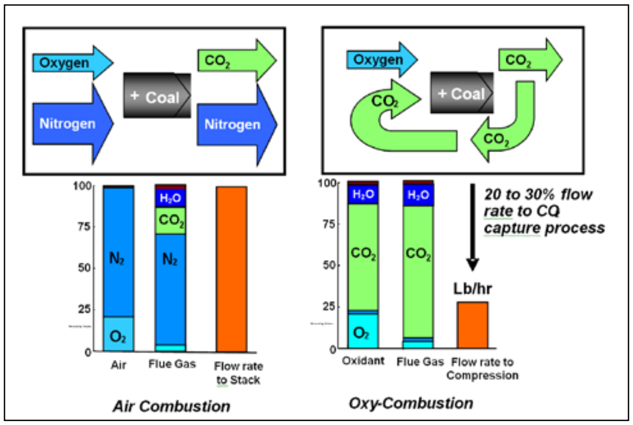

Fig. 9 Oxidant and combustion byproducts.

time to achieve the same removal performance will result in component volume disproportionate to gas flow. For an ESP, the same power would be required for the same loading and sparking would tend to occur at a lower voltage. The plate area will be set by these considerations rather than gas flow and since the cost of auxiliaries is essentially unaffected, the total cost reduction will not be nearly as great as the gas flow reduction. The impact on a fabric filter is similar, though the limiting factors are a bit different. Higher loading requires a lower filtration velocity to maintain a practical back-pulsing frequency.

For the wet or dry scrubber, the amount of SO_2 has not changed, so fresh and spent slurry and the reagent quantities will be about the same and the cost impact on the auxiliary equipment and the reagent are minimal. The tower diameter could be reduced in proportion to the gas volume flow, assuming the same gas velocity would be maintained, but since the same slurry flow is required more spray levels and trays will be necessary in a wet scrubber which increases tower height and gas side pressure drop.

Practical design of an oxycombustion pulverized coal plant with low or no recycle using available materials, fabrication, and construction methods is questionably possible. If it could be achieved, it would resent much higher performance risks and the cost savings in the equipment downstream of the boiler would likely be offset by the enormous increase in boiler cost.

Retrofit Application: Some also think that oxy-coal is not as conducive to retrofit as PCC is. Early studies of small older plants with no existing scrubber may have led many to this conclusion. Actually, oxy-combustion and PCC require very similar site characteristics and oxy-combustion has the advantage of not imposing on the steam turbine. Both require particulate removal and SO_2 scrubbing and space for compression equipment.

PCC requires space for a polishing scrubber, the absorption and regeneration towers, reboiler, piping, pumps and so on, and it requires either major modifications to the existing LP steam turbine or a separate boiler to produce the significant amount of low pressure regeneration steam. Oxy-combustion requires space for a dehumidifier, which also polishes some SO_2, and the ASU. It turns out that the total footprint of this equipment is essentially the same and the base plant requirements are essentially the same, but PCC has the added complication of steam turbine modifications or another boiler.

So oxy-combustion is just as easy to retrofit as PCC and currently is expected to be more economical if 90% capture is needed. The greatest advantage PCC has for retrofit is the ability to install a smaller, lower cost system and remove only part of the CO_2. But it has been shown by DOE and others that the cost of CO_2 removed or avoided for partial capture is higher than 90% capture. Partial capture with oxy-combustion may also be competitive if operated beneficially.

Financial Viability: Capturing and storing CO_2 has an associated cost. Although effort and experience will bring that cost down, this added cost must somehow be paid if a project is to be viable. The added cost has two components: 1) the initial capital cost for the added equipment, and 2) the increased operating cost of having to burn more fuel and process more flue gas to generate the same net output, or provide some other means of compensating for the higher auxiliary power required. Unless the cost of electricity for a CCS plant becomes competitive with one without CCS, it will not dispatch.

Without a value for CO_2 there is no offset to the added costs, and CCS is not viable. This is the current state in the U.S. and most of the world. Although CO_2 does currently have value for enhancing oil recovery, it is insufficient to offset current CCS costs. Commercial deployment of CCS will require legislation that imposes a high enough CO_2 penalty to make dispatch of a more expensive CCS, and solar, or wind plant at least as attractive as conventional power generation technologies.

If oxy-combustion has the opportunity to mature, the potential for cost reduction is significant. Based on Figures 6 and 7, the LCOE for a commercial oxy-coal plant today would be about 52% higher than a modern air-fired plant for the same net output. With ultra supercritical steam conditions in a decade or so, it comes down to about 38.5%.

ASU and CPU cost reductions are also expected, not only through process improvements, but also in component development. Without considering major component technology changes, Air Liquide's record of process advancements alone shows the potential contribution. In addition, technologies like Ramgen's supersonic compressor technology, currently being developed in cooperation with the DOE, offer potential for significant reductions in power consumption and cost for large compressors such as those in both the ASU and CPU.

Air Liquide expects to achieve an additional 10% reduction in power consumption for both the ASU and CPU with experience and technological advancements such as those mentioned. They have also targeted a reduction of about 15% in capital cost for the ASU and as much as 30% for the CPU. Assuming these reductions and the steam cycle improvement, and using the DOE study methodology and financial assumptions with bituminous coal, the calculated net efficiency increases to about 39.7% and LCOE reduces to around 8.24¢ compared to 39.4% and 6.32¢/kW respectively for the equivalent conventional air-fired plant. This is slightly higher efficiency and an increase of only 30.4% in LCOE with CCS compared to a current conventional plant, a potential reduction well below DOE's current target of 35%.

Transportation and Storage Issues: Perhaps the greatest obstacle and unknown for CCS at this time are the transportation and storage issues. Two of the storage options for CO_2 from power plants are enhanced coal bed methane, and enhanced oil recovery, both of which have limited capacity and insufficient value to support CCS deployment. The option that has sufficient capacity is storage in deep saline formations, but it provides no monetary return. Millions of tons of CO_2 have already been injected into the ground over several decades for enhanced oil recovery so there are no significant technological barriers except monitoring methods and regulations.

The experts also indicate that there is adequate storage capacity in deep saline reservoirs, some predicting the coal supply will be depleted before storage space is exhausted. But there is a public fear regarding long-term storage which will have to be overcome by education and that will take some time and an organized effort. Connecting power plants to storage sites is also challenging because fuel sources and storage site locations are often not very close to each other. Pipelines will be needed and installation of pipelines is sure to face stiff opposition. Long-term liability for the stored CO_2 must be resolved in a way that allows storage. Finally, any new regulations must be well defined and accepted. These are not trivial and may be considered much more difficult and fraught with delays than the technologies.

Conclusion

In conclusion, oxy-combustion development has reached the stage of demonstration. In spite of the fact that it promises lower cost and higher efficiency than the other CCS options, no demonstration projects have been awarded in the U.S., and only two are being considered in Europe and one in Australia. This is partially because it cannot be done on a slip stream; the entire combustion system must be converted. In addition, CCS in general faces enormous obstacles. For CCS to be financially viable, a suitable value for CO_2 must be established. The public must be educated and regulations and liability issues for transport and storage of CO_2 must be defined.

Oxy-coal technology is ready NOW for demonstration at meaningful scale and B&W PGG and AL continue to pursue that end.

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