

SMR 1585 - 10

WORKSHOP ON DESIGNING SUSTAINABLE ENERGY SYSTEMS
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*Options for Mitigating Environmental Pollution from
Energy Production and Uses*

Chae Young LIM
K.A.E.R.I., Korea Atomic Energy Research Institute,
Nuclear Policy Division, Daejeon, Korea

These are preliminary lecture notes, intended only for distribution to participants.

Options for Mitigating Environmental Pollution from Energy Production and Uses

Chae Young Lim
(limcy@kaeri.re.kr)

How to reduce the emission in the energy system?

- Demand side management
 - Industrial shift to Low energy intensity
 - Energy Saving
 - Efficiency Improvement
- Supply side measures
 - Control technologies with fossil fuel combustion
 - Fuel treatment (SO₂)
 - Combustion modification (NO_x)
 - Post-combustion control (SO₂, NO_x, PM)
 - Fuel switching
 - Alternative energy technology

Air pollutants emitted by Fossil Fuel-Fired Power Plants

- Particulate Matter (PM)
- Sulfur Oxides (SO_x)
- Nitrogen Oxides (NO_x)
- Carbon Dioxide (CO₂)
- Carbon Monoxide (CO)
- Volatile Organic Compounds (VOC)
- Air Toxics (heavy metals, organics, etc.)

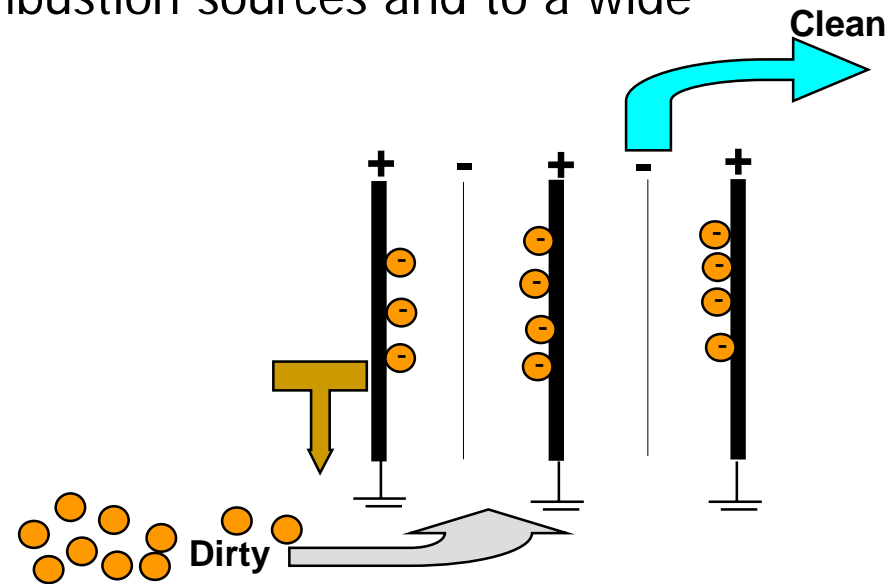
PARTICULATE MATTER ABATEMENT TECHNOLOGIES

Emission Control Techniques for Particulate Matter(PM)

- Principle control techniques are post-combustion methods
 - Electrostatic precipitators (ESP)
 - Fabric filters (or baghouse)
 - Wet scrubber
 - Cyclone separator or multiclone collector
 - Side stream separator
- In case of small stoker-fired boilers, combustion modifications can reduce the PM emissions

Electrostatic Precipitators (ESP)

- Use an Electrostatic Field to Separate Charged Particles from the Flue Gas
 - dry ESP: removal by vibration or “rapping”
 - wet ESP: removal by flushing/washing with water (less re-entrainment)
- Applicable to a variety of coal combustion sources and to a wide range of system sizes
- High efficiency
 - over 99% for 0.1 μm - 10 μm



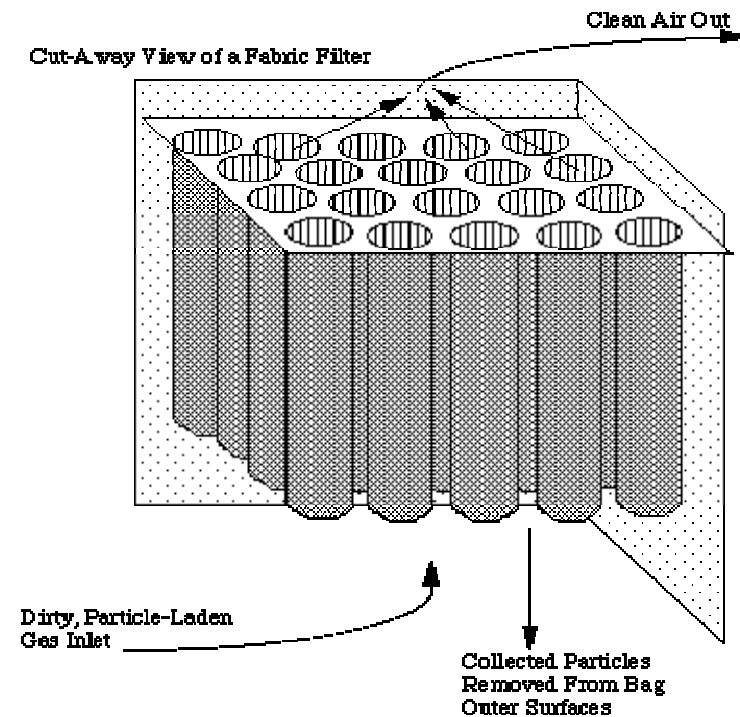
Cost of ESPs

- Typical costs of a new ESP: US\$40 ~ 60/kW
 - designed to remove 99.0 to 99.7 percent PM
 - Higher collection efficiency may increase the cost up to 100 US\$/kW
- Typical O&M costs of conventional ESP: 2 ~ 4 US\$/MWh



Fabric Filters (Baghouse)

- Particles and flue gas are separated in tube-shaped filter bags
- Main Alternative to ESPs for Large Coal-Fired Power Plants
- Widely used in the developed countries mostly since early 1970s
- Collection efficiency: upto 99.9%



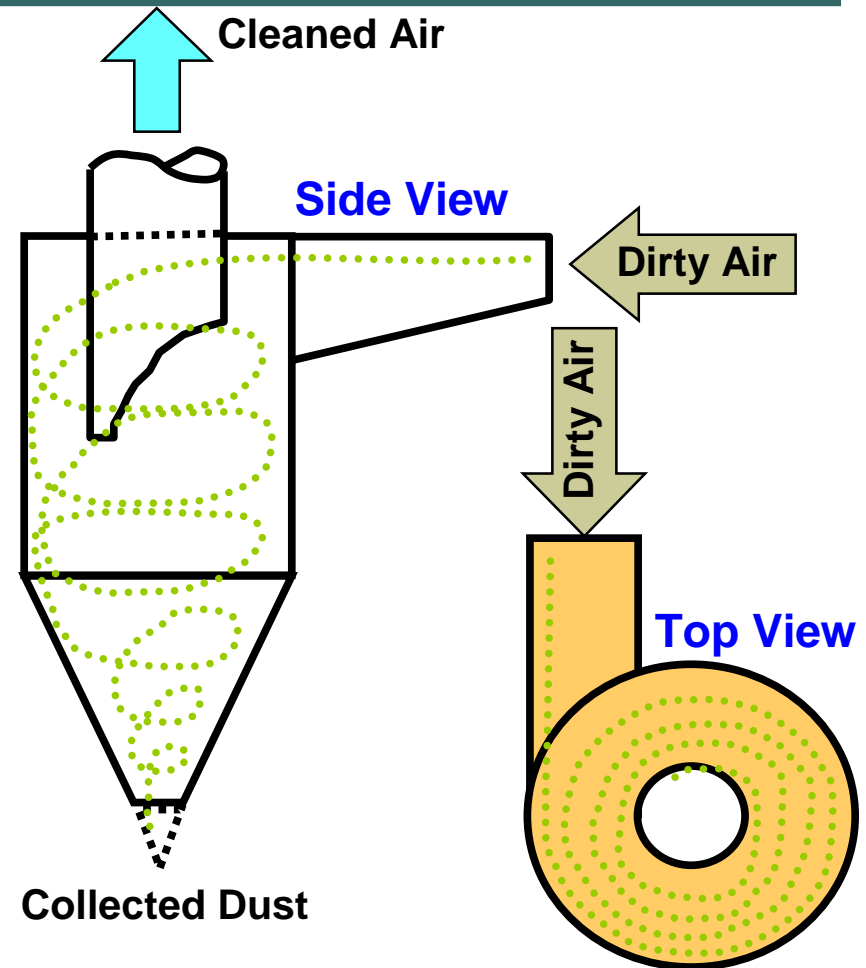
Cost Effectiveness of Baghouses

- In general, ESPs are more competitive than baghouses
 - lower capital and levelized costs for collection efficiency below 99.0 to 99.5%
- In cases in which more than 99.5% collection efficiency is required, especially for low-sulfur coals, baghouses are more cost-effective
- Typical costs for baghouses: US\$50 ~ 70/kW
- Levelized costs: 3.5 to 4.5 US\$/MWh for baghouses



Cyclone separator

- Make Use of Gravity and Inertia
- Simpler and Relatively inexpensive Technology
- Can be installed singly, in series or grouped as in a multiclone collector
- Often used as a precollector upstream of an ESP, fabric filter, or wet scrubber
- Relatively ineffective for collection of PM-10 (particles less than 10 micron)
 - Overall collection efficiency: 90-95%



SO_x

ABATEMENT TECHNOLOGIES

Emission Control Technologies for Sulfur Dioxide (SO_x)

- Switch to low sulfur coals
- Remove sulfur from fuel (cleaning)
- Advanced combustion techniques (e.g., fluidized bed combustion)
- Remove SO_x from combustion flue gas using post-combustion emission control technology
 - e.g. flue gas desulfurization (FGD) techniques

Switch to Low Sulfur coals

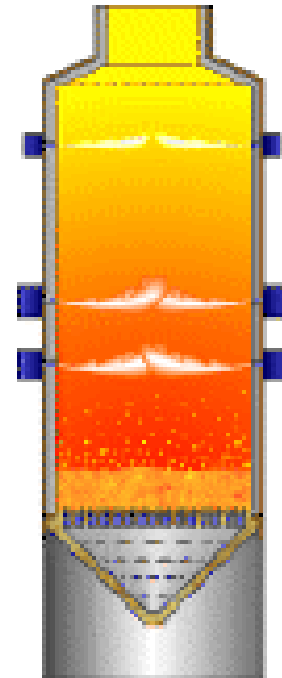
- Typical sulfur contents in coal is 0.5% ~ 5.0%
- Break point between high and low sulfur coal
 - 1,100 ng/J (2.5 lbs SO₂/million BTU)
 - Equivalent to 1.5% sulfur (bituminous), 1% sulfur (subbituminous)
- Can be used in Pulverized coal(PC) and Fluidized bed combustion(FBC) boilers
 - In the case of PC systems, substitutions are limited
- Low sulfur coal, in general, may be connected with the following problems
 - higher ash content
 - lower heating value
 - more moisture
 - may degrade ESP performance: higher resistivity of the fly ash

Removing Sulfur from Fuel

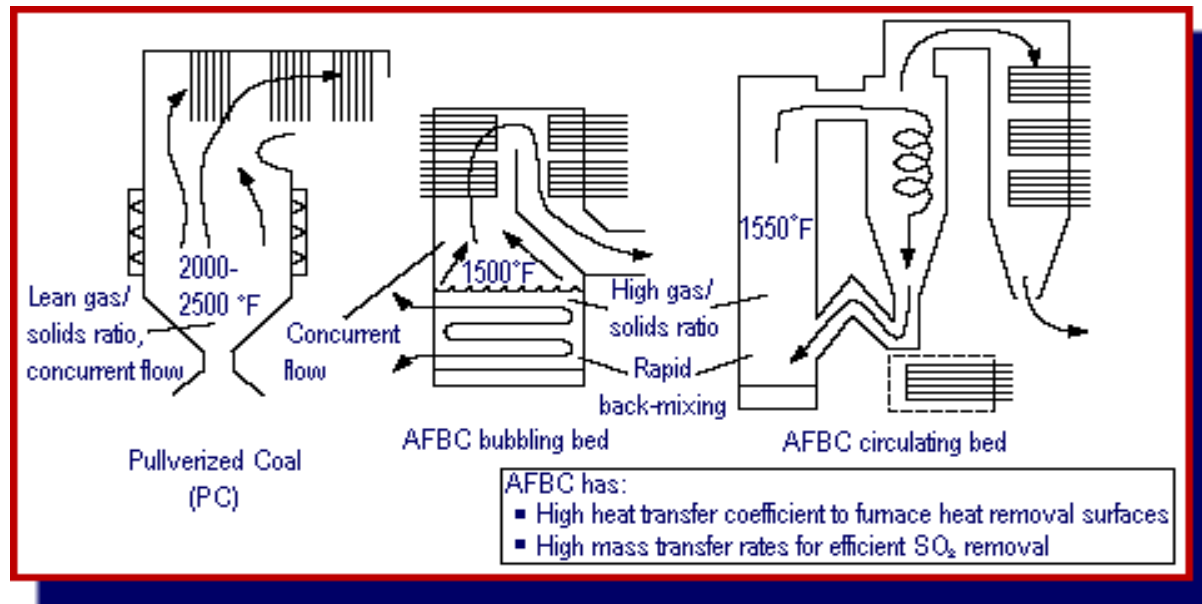
- Physical coal cleaning(benefication) process
 - Originally envisioned as an ash reduction technology
 - Ash removal can reach 60 percent
 - Can remove 20-50% of the pyritic sulfur(FeS_2)
 - Can not remove organic sulfur
 - Total possible reduction(10-40%) is dependent on the ratio of pyritic to organic sulfur
 - Thermal recovery (percent of heating value retained) is 85 to 98 percent.
 - In most cases, cleaning costs range from US\$1 to US\$5/ton.
- Chemical and biological benefication process
 - to remove organically bound sulfur
 - Under development but not yet commercialized

Fluidized bed combustion boiler(FBC)

- Coal combustion occurs within a bed of either sorbent or inert material (usually sand), fluidized by an upward flow of air
 - Calcium-based limestone or dolomitic sorbent is often used
 - Bed temperature are maintained between 760-870°C to promote the sulfation reaction
- It can lower SO₂ and NO_x emissions
 - Sulfur is retained as a solid sulfate and is removed from the flue gas stream by the particulate control device
 - NO_x are reduced because it can operate at lower combustion temperature (well below the threshold where nitrogen oxides form, 1400°C), thus reducing the fixation of atmospheric nitrogen
- It may tax conventional particulate control system
 - Particulate mass concentration is 2-4 times higher than PC-boilers
- Two different types
 - Atmospheric FBC
 - Pressurized FBC



Atmospheric Fluidized Bed Combustion (AFBC)

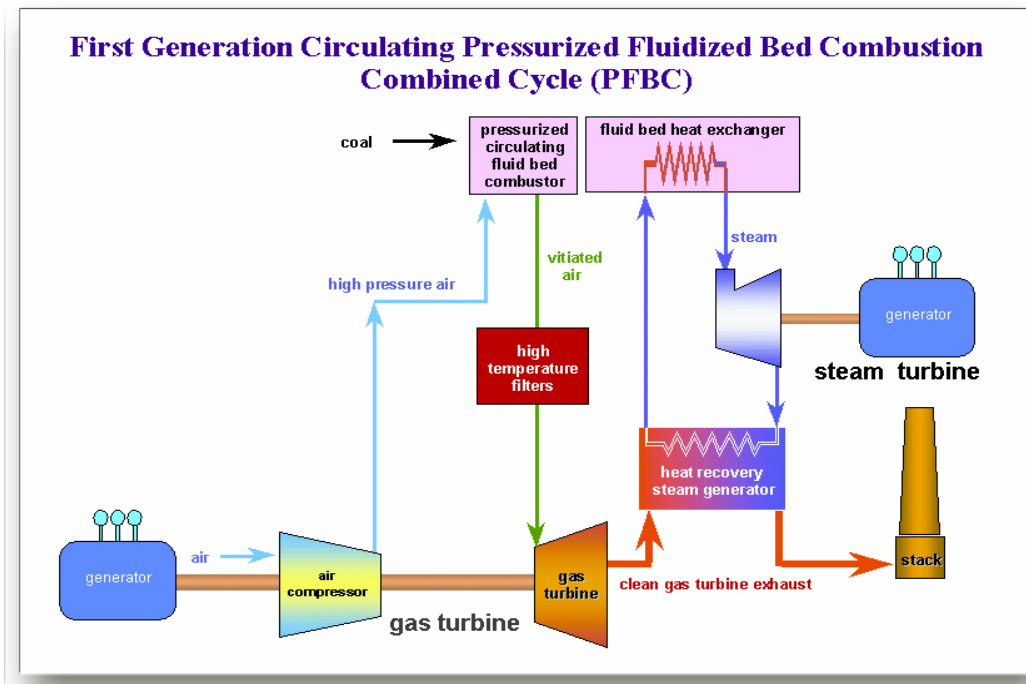


SO₂ removal

- Bubbling AFBC: 70-90%
- Circulating AFBC: up to 95 %

- Projected capital costs: US\$1000 to 1300/kW(150-300 MW AFBC)
 - AFBC technology is the technology of choice when
 - fuel flexibility is desirable,
 - low-quality fuels are available,
 - low-NO_x emissions are required,
 - medium (70 to 90 percent) SO₂ removal is desired

Pressurized Fluidized Bed Combustion (PFBC)



SO₂ removal

more than 90%

Thermal Efficiency

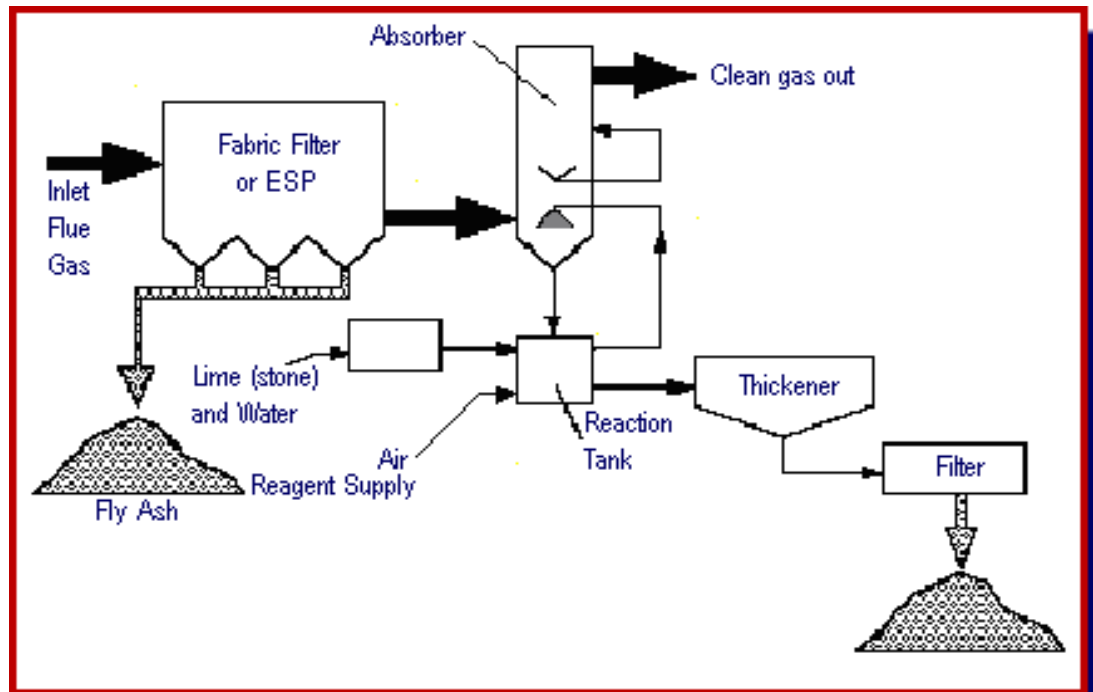
40-42% with combined cycle

- Boiler operates at higher than atmospheric pressure (0.5 to 2 MPa)
 - the gas is cleaned downstream from the PFBC boiler, and the gas is expanded in a gas turbine
- Projected capital costs: US\$1150 to 1250/kW
 - fuel flexibility, modularity, and suitability for retrofit

Post-combustion SO₂ control for coal combustion

Control Technology	Process	Typical Control Efficiencies	Remarks
Wet scrubber (Wet FGD)	Lime/limestone	80 - 95+%	Applicable to high sulfur fuels, wet sludge product
	Sodium carbonate	80 - 98%	5-430 million Btu/hr typical application range, high reagent costs
	Magnesium oxide/ hydroxide	80 - 95+%	Can be regenerated
	Dual alkali	90 - 96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray drying (Dry FGD)	Calcium hydroxide slurry, vaporizes in spray vessel	70 - 90%	Applicable to low and medium sulfur fuels, produces dry product
Furnace injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25 - 50%	Commercialized in Europe, several U. S. demonstration projects are completed
Duct injection	Dry sorbent injection into duct, sometimes combined with water spray	25 - 50+%	Several research and development, and demonstration projects underway, not yet commercially available

Wet Scrubber (wet FGD)



SO₂ removal

- 80-95%
- 95-99%(with additive)

Power usage

- 1-2% of total generating capacity

- Use an alkaline reagent slurry to absorb SO₂ in the Flue Gas
- Many variations for wet FGDs (limestone forced oxidation, dual alkali, ammonia, sodium carbonate)

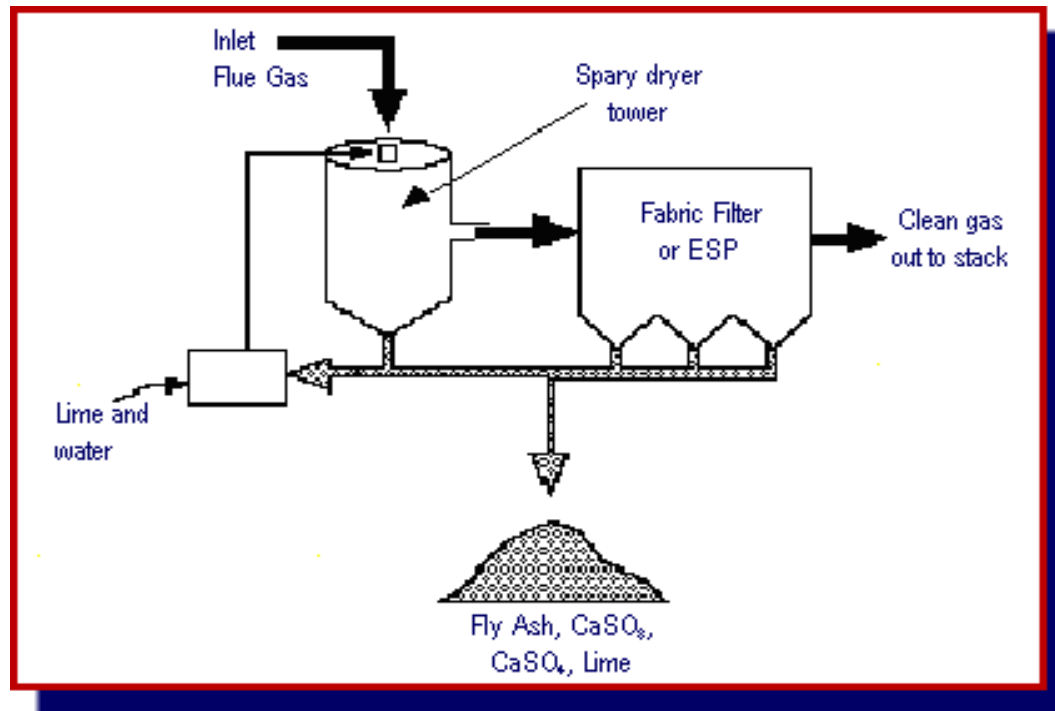
Cost-Effectiveness of Wet FGD

Cost Factor	Retrofit	New Plant
Capital Cost (US\$/kW)	100 - 150	70 - 150
Variable O&M (USmills/kWh)	1.5 - 3.3	1.3 - 3.2
Total O&M (USmills/kWh)	6.6 - 12.0	7.4 - 13.0

Costs are expressed in 1990 US\$

- Adding a wet FGD onto an existing power plant (retrofit) is typically more expensive than the same wet FGD for a new power plant
- Costs typically vary by size, sulfur content of coal, etc

Spray Dryer(Dry FGD)



SO₂ removal

- 70-90% with low sulfur coals

Power usage

- 0.5-1% of total generating capacity

- Developed as a cheaper alternative to wet scrubbers
- Demonstration may be needed for high sulfur coals
- By-product must be disposed of

Cost Effectiveness of Dry FGDs

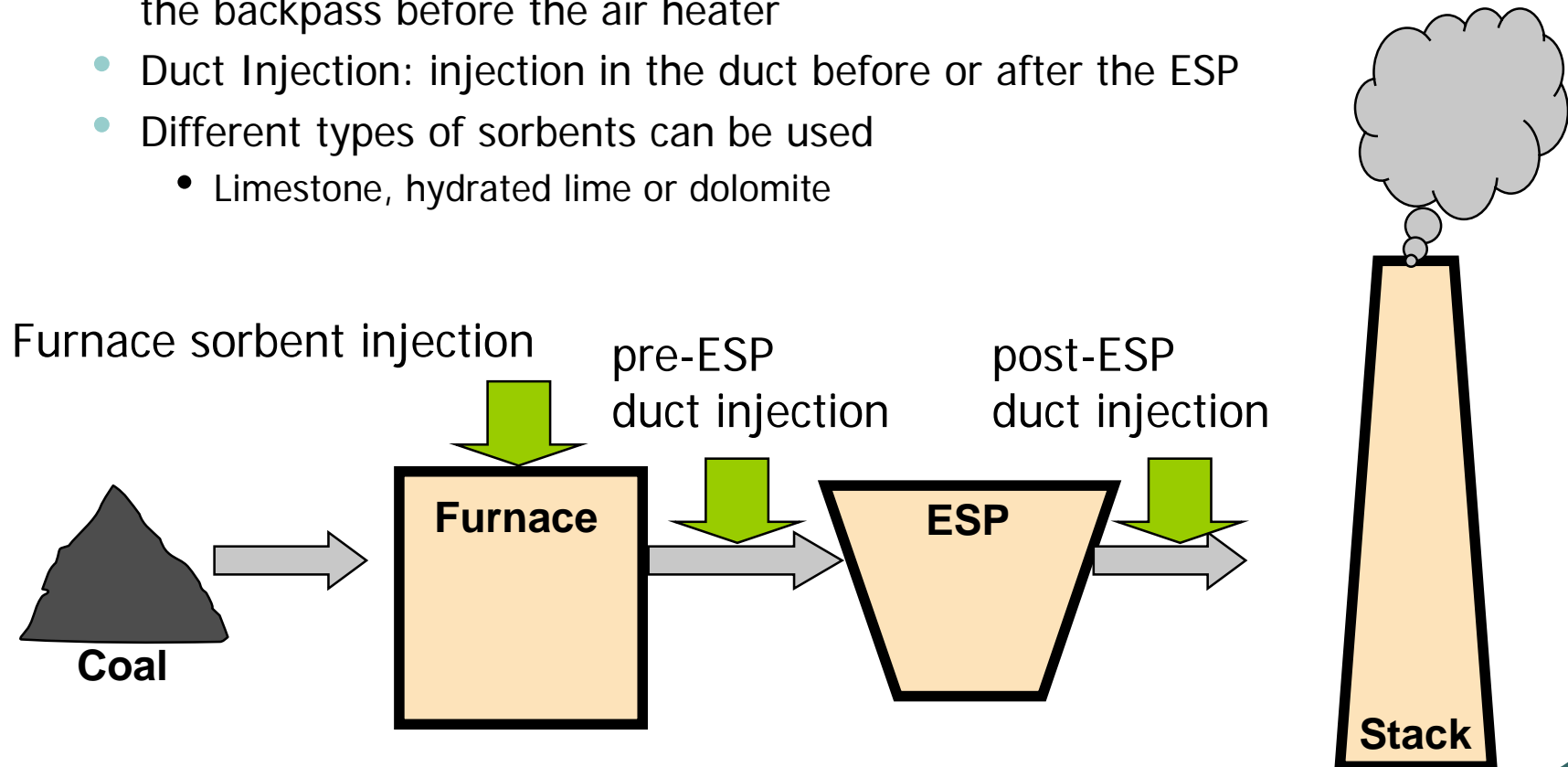
Cost Factor	Retrofit	New Plant
Capital Cost (US\$/kW)	140-210	110-165
Variable O&M (USmills/kWh)	2.1-3.2	2.1-3.2
Total O&M (USmills/kWh)	6.0-9.0	7.4 - 11.0

Cost data reflects 1990-92 experience

- Costs are lower than for wet FGDs because the system is simpler and easier to operate and maintain
- As wet FGDs are being simplified and costs are reduced, it becomes more difficult for dry FGDs to compete based on cost-effectiveness (\$/ton of SO₂ removed) considerations

Sorbent Injection

- Sorbent can be injected at different locations
 - Furnace Sorbent Injection: the injection point is above the burners or in the backpass before the air heater
 - Duct Injection: injection in the duct before or after the ESP
 - Different types of sorbents can be used
 - Limestone, hydrated lime or dolomite



Cost effectiveness of Sorbent Injection

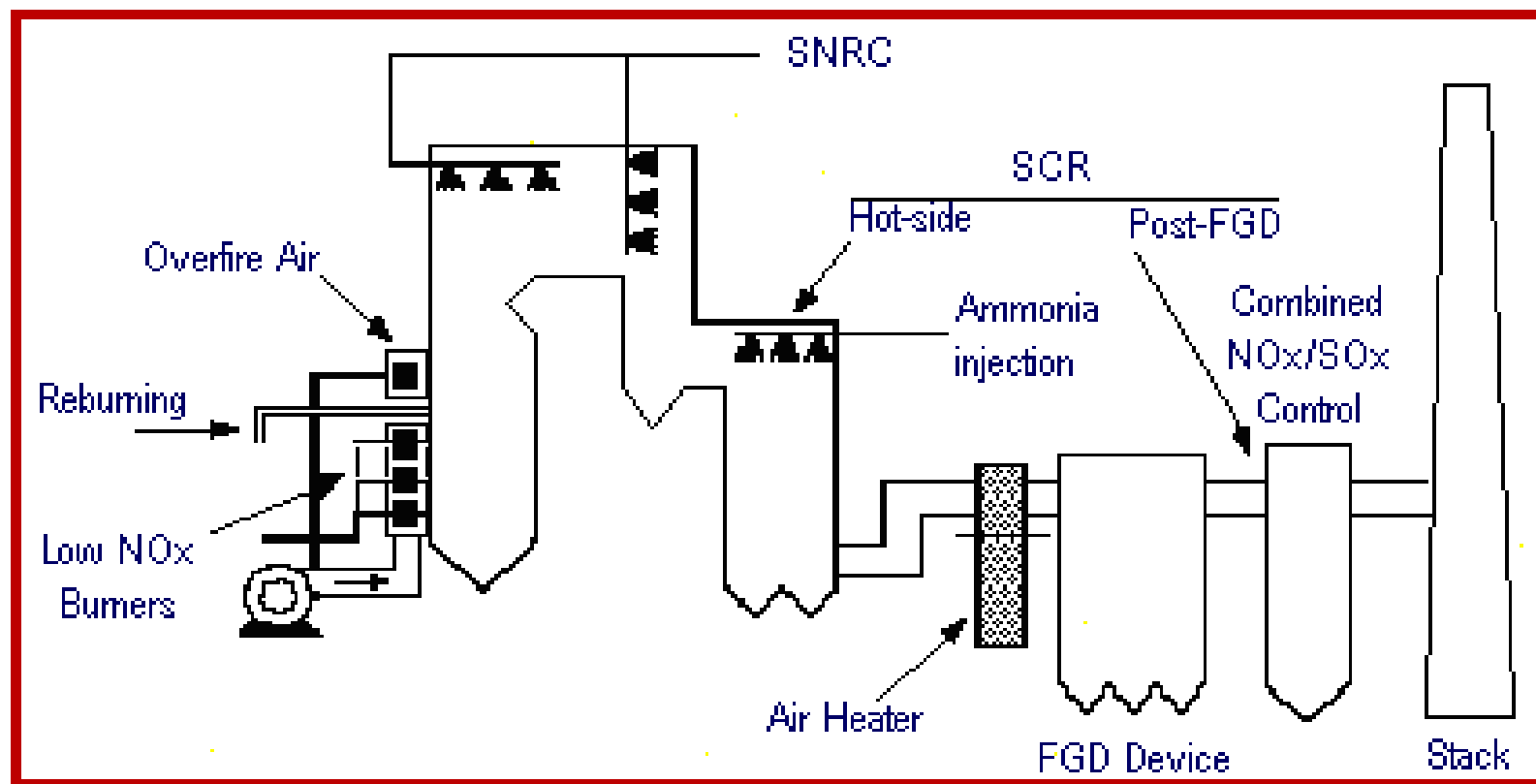
- Sorbent injection is simple and has lower capital and operating costs than scrubbers
 - Other advantages of the technology are that it requires very little space, uses readily available additives (sorbent), and is easy to operate and maintain
- but it has limited SO₂ removal (30 to 60 percent) capability
- Capital cost: 70-120 US\$/kW
- variable operating cost: 3-7 USmills/kWh.
- Sorbent injection is typically used for retrofit applications

NO_x ABATEMENT TECHNOLOGIES

Emission Control Technologies for NOX

- Operational modifications
 - Changing certain boiler operational parameters can create conditions in the furnace that will lower NO_x production.
 - e.g. Burners-out-of-service (BOOS), Low excess air (LEA), Biased firing (BF)
- Combustion modifications
 - designed to 'staged' combustion
 - e.g. NO_x Burners, Overfire Air, Reburning, Flue Gas Recirculation
- Post-combustion treatment
 - reducing agent (typically NH₃) is injected and it reacts with NO_x
 - e.g. Selective Catalytic Reduction, Selective Noncatalytic Reduction, Hybrid Processes

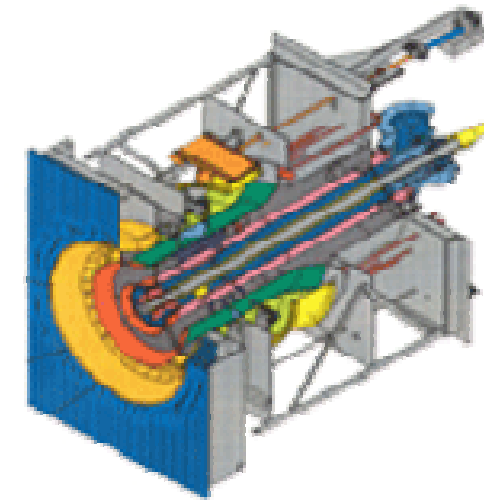
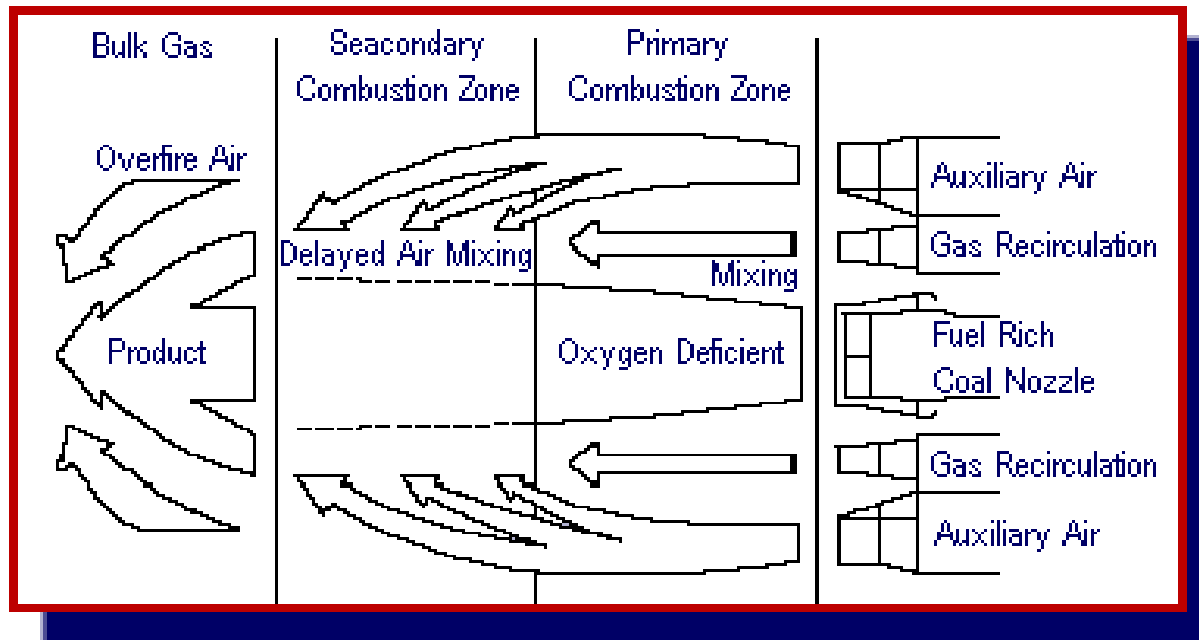
Combustion and Post-combustion NO_x Control Options



Characteristics of Combustion modification

Control Technique	Description of Technique	Applicable Boiler Designs	NOx Reduction Potential ^b (%)	Commercial Availability/R & D Status
Operational modifications	Rearrangement of air or fuel in the main combustion zone	Pulverized coal boilers (some designs); Stokers	10 -20	Available
Overfire Air	Injection of air above main combustion zone	Pulverized coal boilers and stokers	20 -30	Available
Low NOx Burners	New burner designs controlling air-fuel mixing	Pulverized coal boilers	35 -55	Available
LNB with OFA	Combination of new burner designs and injection of air above main combustion zone	Pulverized coal boilers	40 -60	Available
Reburn	Injection of reburn fuel and completion air above main combustion zone	Pulverized coal boilers, cyclone furnaces	50 -60	Commercially available but not widely demonstrated

Low NO_x Burners



- Are designed to stage combustion
- A fuel-rich zone is created by forcing additional air to the outside of the firing zone (auxiliary air) and by delaying the combustion of coal

Cost effectiveness of Low NOx burner

Technology	Investment Cost (US\$/kW)		O&M cost (mill/kWh)	
	Retrofit	New Boiler	Retrofit	New Boiler
LNB	5-10	1-3	<1	None
LNB + OFA	10-25	3-10	<1	None
Reburning	20-50	10-30	1-4	1-4

- LNB and LNB + OFA are being used commercially in industrialized countries
- New boilers in industrialized countries all use low-NOx burners

Characteristics of Post-Combustion emission control

Control Technique	Description of Technique	Applicable Boiler Designs	NOx Reduction Potentialb (%)	Commercial Availability/R & D Status
SNCR	Injection of NH ₃ or urea in the convective pass	Pulverized coal boilers, cyclone furnaces, stokers, and fluidized bed boilers	30 -60	Commercially available but not widely demonstrated
SCR	Injection of NH ₃ in combination with catalyst material	Pulverized coal boilers, cyclone furnaces	75 -85	Commercially offered, but not yet demonstrated
LNB with SNCR	Combination of new burner designs and injection of NH ₃ or urea	Pulverized coal boilers	50-80	Commercially offered, but not widely demonstrated as a combined technology
LNB with OFA and SCR	Combination of new burner design, injection of air above combustion zone, and injection of NH ₃ or urea	Pulverized coal boiler	85-95	Commercially offered, but not widely demonstrated as a combined technology

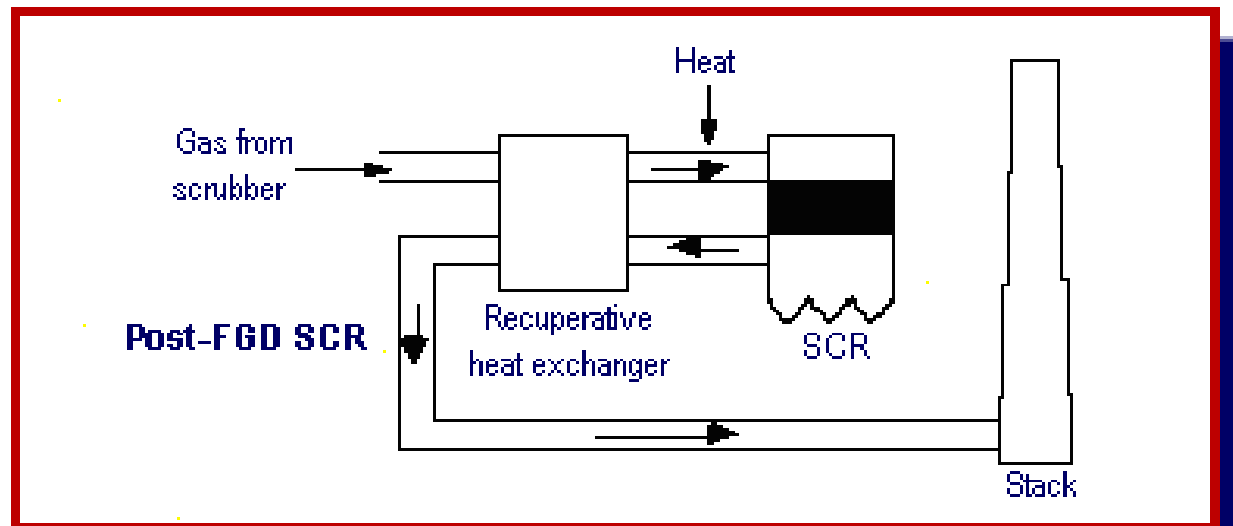
Selective Non-Catalytic Reduction (SNCR)

- The technology was initially demonstrated in boilers fired by oil or natural gas
- Urea(CH_2CONH_2) is injected into the flue gas to convert NO_x to elemental nitrogen and water
- The chemical reactions, in a simplified form are as follows
 - $2\text{NO} + \text{NH}_2\text{CONH}_2 + \frac{1}{2}\text{O}_2 \Rightarrow 2\text{N}_2 + \text{CO}_2 + 2\text{H}_2\text{O}$
- Uses higher furnace temperatures (900-1100°C)

	retrofit	New plant
Investment cost (US\$/kW)	10-20	5-10
Operating cost (mills/kWh)	1-2	1-2

Selective Catalytic Reduction (SCR)

- Ammonia is injected into the flue gas to convert NO_x to elemental nitrogen and water using a catalyst
 - The catalyst is needed because SCR systems operate at much lower temperatures (340 to 380°C)
 - The most commonly used catalysts are a vanadium/titanium formulation (V_2O_5 stabilized in a TiO_2 base) and zeolite materials



Cost-Effectiveness of SCR

- Capital costs depend on
 - the required NO_x emission reduction
 - unit layout (available space and interferences)
 - catalyst unit price
 - cost of ammonia
 - type of SCR (hot-side vs. post-FGD)
- O&M costs for SCR depend on
 - the catalyst life (typically 3 to 5 years)
 - the catalyst cost (typically 16,000-20,000 US\$/m³)

	retrofit	New plant
Investment cost (US\$/kW)	50-90	90-150
Operating cost (mills/kWh)	2-4	2-4

CO₂ ABATEMENT TECHNOLOGIES

CO₂ Abatement Approach

- Fuel substitution into lower CO₂ emission
- Improving plants efficiency
 - Less coal is burned (producing less CO₂) for the same power output
 - Enhanced steam condition -> efficiency reach above 40%
 - Advanced coal technology such as PFBC, IGCC
- CO₂ capture
 - Flue gas approach - Capture CO₂ from the combustion flue gas
 - Oxygen combustion
 - Hydrogen (Syn-Gas)

Flue gas approach

- Absorption

- Chemical absorption: Chemical stripping with solvents such as mono-ethanolamine (MEA), di-ethanolamine (MEA), etc.
- Physical absorption: commonly used in commercial processes

- Adsorption

- Separate CO₂ by adsorption with some materials with high surface areas such as zeolites and activated carbon
- Pressure Swing Adsorption(PSA), Temperature Swing Adsorption(TSA), Electrical Swing Adsorption(ESA)

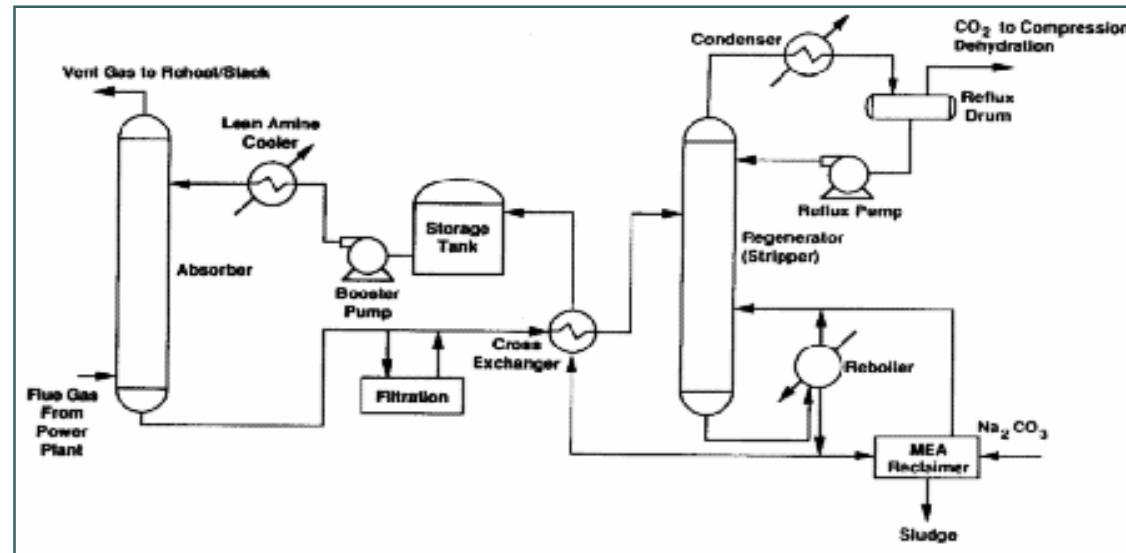
- Cryogenics/CO₂ recycle

- CO₂ is cooled below its boiling point, and turn into the liquid state
- Requires too much energy and is uneconomic

- Membranes

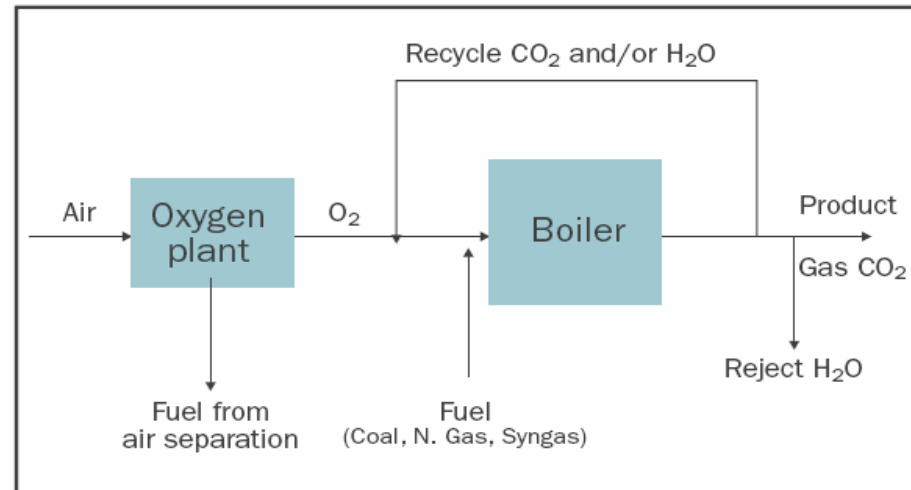
- Barrier film that allows selective and specific permeation
- Gas separation membranes and gas absorption membranes

Amines Separation Process(MEA)



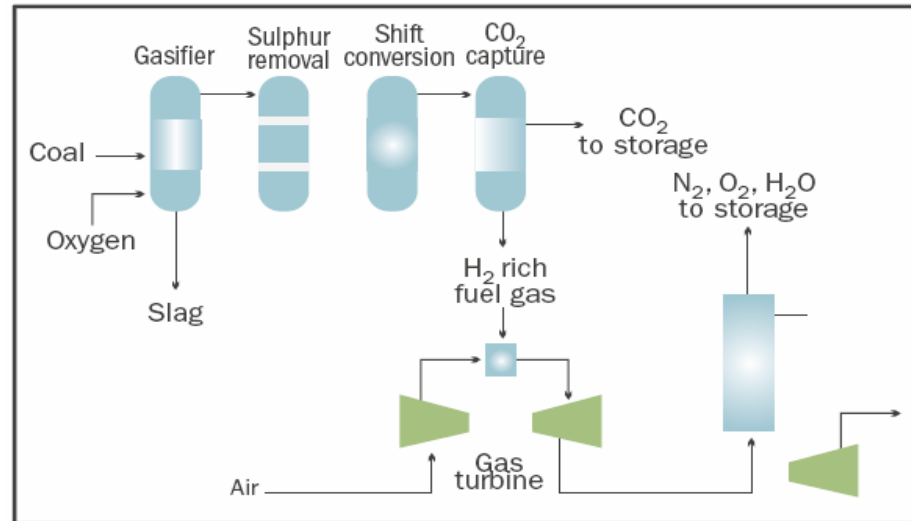
- Widely used in removing CO₂ from natural gas reservoirs
- CO₂ in the flue gas comes in contact with the MEA solution in the absorber
- The MEA selectively absorbs the CO₂ and is then sent to a stripper
- In the stripper, the CO₂-rich MEA solution is heated to release almost pure CO₂
- The lean MEA solution is recycled to the absorber

Oxygen Combustion Approach



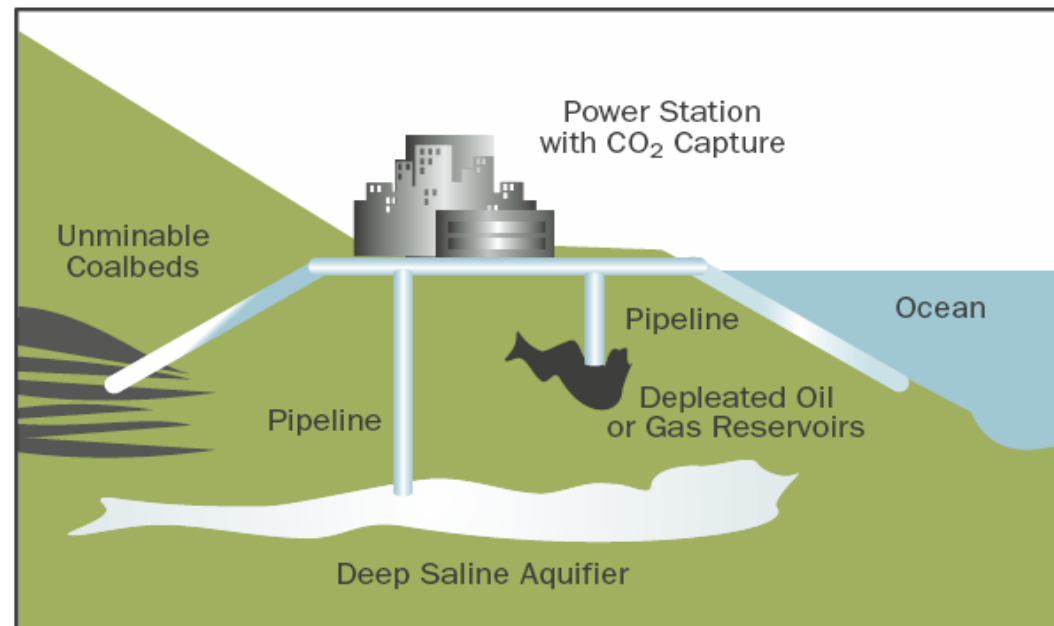
- Increases CO₂ concentrations by increasing O₂ levels and reducing N₂ contents in the combustion air
 - With higher O₂ concentrations, the flue gas is then re-circulated to control combustion temperature
- Advantage: the volume of inert gas is reduced, which can increase boiler thermal efficiency
- Drawback: the production of O₂ using conventional cryogenic air separation plants is expensive, therefore, the process is highly inefficient

Hydrogen/Syngas approach



- a pre-combustion capture technology that removes the carbon content (“decarbonizes”) of fossil fuels, and produces a CO₂-rich by-product stream
- It is an approach used for both H₂ production and electricity generation
- When electricity (rather than H₂) is the desired product, coal is gasified in an IGCC power plant to produce a syngas consisting of CO and H₂
- The syngas can then be used in a gas turbine and the highly concentrated CO₂ can be captured and stored

CO₂ Sequestration Options & Mechanisms



- Hydrodynamic trapping: trapped as a gas
- Solubility trapping: dissolves into the fluids
- Mineral trapping: reacts directly or indirectly with minerals to become part of solid mineral matrix

Capacity of potential CO₂ storage sites

Sequestration Option	Worldwide Capacity
Ocean	10002 GtC
Deep Saline Formations	100s—1000s GtC
Depleted Oil and Gas Reservoirs	100s GtC
Coal Seams	10s—100s GtC
Terrestrial Ecosystems	10s GtC
Utilization	<1 GtC/yr

- Total worldwide anthropogenic CO₂ emissions are the equivalent of about 7 GtC
- Potential worldwide CO₂ storage capacity is enormous

Projected Cost of CO₂ Capture & Sequestration

- CO₂ capture
 - the costs of capturing CO₂ from various fossil power plants range from US\$16-87 per tonne CO₂ avoided
 - NGCC with capture via amine scrubbing of flue gas and IGCC with pre-combustion capture of CO₂ as the two most promising options
- CO₂ transportation & sequestration
 - transport by pipeline costs around \$1–\$3 per ton
 - transport and storage costs are somewhere between 5-21/ton CO₂ depending on transport distance and storage method
 - Costs are about one third of the total CO₂ cost for sequestration projects

References

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- <http://www.worldbank.org/html/fpd/em/power/EA/mitigatn/thermair.htm>
- <http://www.epa.gov/ttn/chief/ap42/index.html>
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