



Environmental Compliance: Emission Control of Boilers

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Corrosion and Water Management Consultants

“Improving Plant Performance, Availability & Reliability by Chemical Interventions”

**Total Installed Capacity (As on 31.08.2017) -
Source : Central Electricity Authority (CEA)**

Sector	MW	% of Total
State Sector	81,652	24.8%
Central Sector	102,933	31.3%
Private Sector	144,641	43.9%
Total	3,29,226	

**Total Installed Capacity (As on 31.08.2017) -
Source : Central Electricity Authority (CEA)**

Fuel	MW	% of Total
Total Thermal	2,19,490	66.7%
Coal	1,93,467	58.8%
Gas	25,185	7.6%
Oil	838	0.3%
Hydro (Renewable)	44,653	13.6%
Nuclear	6,780	2.1%
RES* (MNRE)	58,303	17.7%
Total	329,226	

* Installed capacity in respect of RES (MNRE) as on 30.06.2017.

Total Installed Capacity (As on 31.08.2017) - Source : Central Electricity Authority (CEA)

ALL INDIA INSTALLED CAPACITY (IN MW) OF POWER STATIONS (As on 31.08.2017) (UTILITIES)

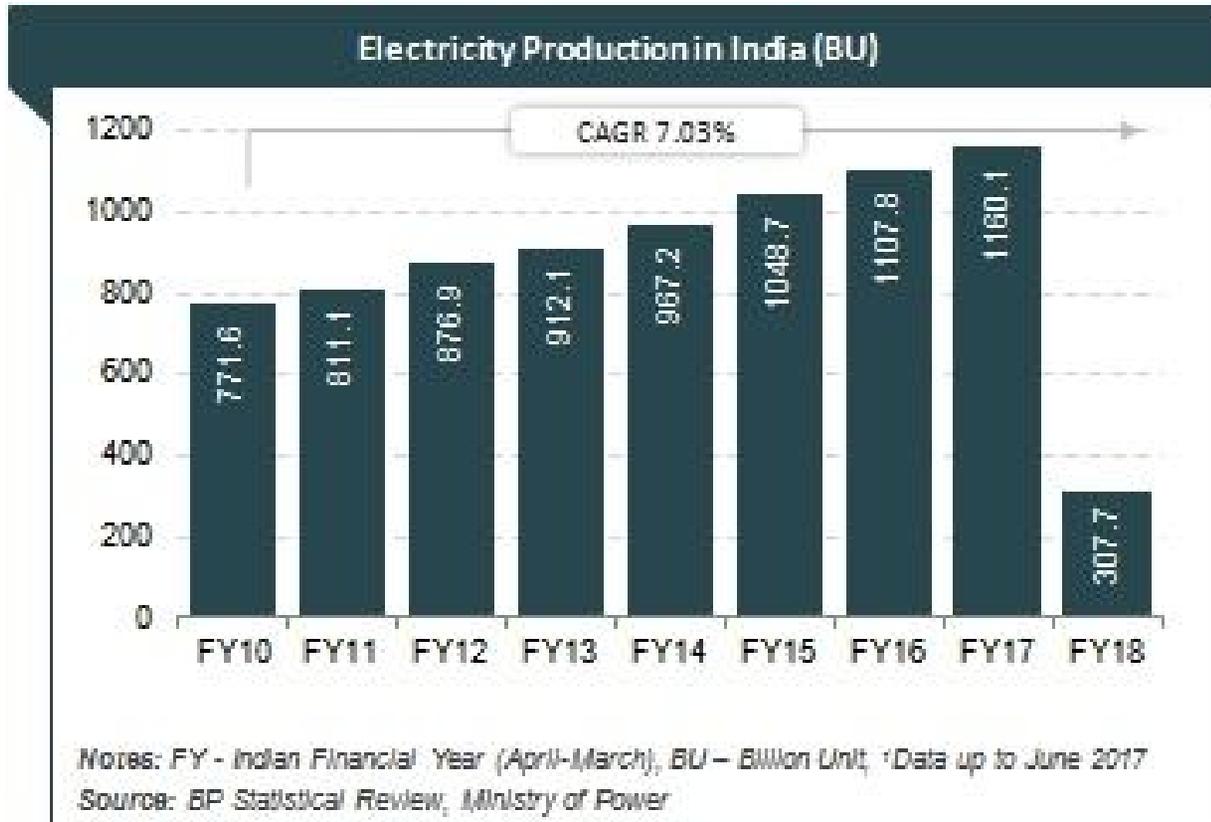
Region	Ownership/ Sector	Modewise breakup							Grand Total
		Thermal				Nuclear	Hydro	RES * (MNRE)	
		Coal	Gas	Diesel	Total				
Northern Region	State	17098.00	2879.20	0.00	19977.20	0.00	8543.55	663.56	29184.31
	Private	22760.83	558.00	0.00	23318.83	0.00	2502.00	11049.36	36870.19
	Central	12630.37	2344.06	0.00	14974.43	1620.00	8266.22	0.00	24860.65
	Sub Total	52489.20	5781.26	0.00	58270.46	1620.00	19311.77	11712.92	90915.15
Western Region	State	22280.00	2849.82	0.00	25129.82	0.00	5446.50	311.18	30887.50
	Private	32875.67	4676.00	0.00	37551.67	0.00	481.00	18100.92	56133.59
	Central	14317.95	3533.59	0.00	17851.54	1840.00	1520.00	0.00	21211.54
	Sub Total	69473.62	11059.41	0.00	80533.03	1840.00	7447.50	18412.10	108232.63
Southern Region	State	17832.50	791.98	287.88	18912.36	0.00	11748.03	512.55	31172.94
	Private	12124.50	5322.10	473.70	17920.30	0.00	0.00	26378.36	44298.66
	Central	13425.02	359.58	0.00	13784.60	3320.00	0.00	0.00	17104.60
	Sub Total	43382.02	6473.66	761.58	50617.26	3320.00	11748.03	26890.91	92576.20
Eastern Region	State	6570.00	100.00	0.00	6670.00	0.00	3537.92	225.11	10433.03
	Private	6225.00	0.00	0.00	6225.00	0.00	291.00	768.63	7284.63
	Central	14806.64	0.00	0.00	14806.64	0.00	1005.20	0.00	15811.84
	Sub Total	27601.64	100.00	0.00	27701.64	0.00	4834.12	993.74	33529.50
North Eastern Region	State	0.00	492.95	36.00	528.95	0.00	422.00	259.25	1210.20
	Private	0.00	24.50	0.00	24.50	0.00	0.00	21.88	46.38
	Central	520.02	1253.60	0.00	1773.62	0.00	890.00	0.00	2663.62
	Sub Total	520.02	1771.05	36.00	2327.07	0.00	1312.00	281.12	3920.19
Islands	State	0.00	0.00	40.05	40.05	0.00	0.00	5.25	45.30
	Private	0.00	0.00	0.00	0.00	0.00	0.00	7.31	7.31
	Central	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sub Total	0.00	0.00	40.05	40.05	0.00	0.00	12.56	52.61
ALL INDIA	State	63780.50	7113.95	363.93	71258.38	0.00	29698.00	1976.90	102933.27
	Private	73986.00	10580.60	473.70	85040.30	0.00	3274.00	56326.45	144640.75
	Central	55700.00	7490.83	0.00	63190.83	6780.00	11681.42	0.00	81652.25
	Total	193466.50	25185.38	837.63	219489.51	6780.00	44653.42	58303.35	329226.27

UNIT WISE BREAK UP OF INSTALLED CAPACITY (MW)

UNIT CAPACITY MW	BEFORE 31.03.2003 (MW)	NO OF UNITS	01.01.2004 ONWARDS (MW)	NO OF UNITS	TOTAL MW
60-110 MW	6875	77	258	4	7133
111-250 MW	39277	198	17211	81	56488
251-499 MW	0	0	12690	43	12690
500 MW	13500	27	27500	55	41000
>500 MW	0	0	61640	96	61640
TOTAL	59652	302	119299	279	178951

* UNITS BELOW 60 MW NOT INDICATED IN ABOVE TABLE

Total Installed Capacity (As on 31.08.2017) - Source : Central Electricity Authority (CEA)



Total Installed Capacity (As on 31.08.2017) - **Source : Central Electricity Authority (CEA)**



After consultation with the power ministry, the environment ministry set in place improved pollution norms for the thermal power industry in 2015. Credit: Reuters

Water Consumption in Thermal Power Plants

S.O. 3305(E).— In exercise of the powers conferred by sections 6 and 25 of the Environment (Protection) Act, 1986 (29 of 1986), the Central Government hereby makes the following rules further to amend the Environment (Protection) Rules, 1986, namely:—

Sr. No.	Industry	Parameter	Standards
"5A.	Thermal Power Plant (Water consumption limit)	Water consumption	<p>I. All plants with Once Through Cooling (OTC) shall install Cooling Tower (CT) and achieve specific water consumption upto maximum of 3.5m³/MWh within a period of two years from the date of publication of this notification.</p> <p>II. All existing CT-based plants reduce specific water consumption upto maximum of 3.5 m³/MWh within a period of two years from the date of publication of this notification.</p>

Contd.

Water Consumption in Thermal Power Plants

Sr. No.	Industry	Parameter	Standards
“5A.	Thermal Power Plant (Water consumption limit)	Water consumption	III. New plants to be installed after 1st January, 2017 shall have to meet specific water consumption upto maximum of 2.5 m³/MWh and achieve zero waste water discharged”;

MINISTRY OF ENVIRONMENT, FOREST AND CLIMATE CHANGE

NOTIFICATION

New Delhi, the 7th December, 2015

EXISTING EMISSION NORMS FOR TPS

Emission parameter	Limiting Values
Suspended Particulate Matter (SPM)	<p>Less than 210 MW (1989) : 350 mg/Nm³ 210 MW or more(1989) : 150 mg/Nm³</p> <p>The above limits were further reduced to 100 mg/Nm³ in 2003 under Corporate Social Responsibilities.</p> <p>Limit of 50 mg/Nm³ is being specified on case to case basis depending on the area</p>
NO _x	None for coal based stations
SO _x	<p>None, stack provided for dispersion <500 MW - 220 m ≥500 MW - 275 m FGD space provision for units size 500 MW and above.</p>



MOEF Notification – 7th Dec. 2015

Pollutants	TPPs (units) installed before 31st December, 2003*	TPPs (units) installed after 1st January,2004, up to 31st December, 2016*	TPPs (units) to be installed from 1st January, 2017**
Particulate Matter (PM)	100 mg/Nm ³	50 mg/Nm ³	30 mg/Nm ³
Sulphur Dioxide (SO ₂)	600 mg/Nm ³ (Units Smaller than 500MW) 200 mg/Nm ³ (for units having capacity of 500MW and above)	600 mg/Nm ³ (Units Smaller than 500MW) 200 mg/Nm ³ (for units having capacity of 500MW and above)	100 mg/Nm ³
Oxides of Nitrogen (NO _x)	600 mg/Nm ³	300 mg/Nm ³	100 mg/Nm ³
Mercury (Hg)	0.03 mg/Nm ³ (for units having capacity of 500MW)	0.03 mg/Nm ³	0.03 mg/Nm ³

*TPPs (units) shall meet the limits within two years from date of publication of this notification.

**Includes all the TPPs (units) which have been accorded environmental clearance and are under construction.

MAJOR TECHNICAL ISSUES FOR THERMAL PLANTS

SUSPENDED PARTICULATE MATTER (SPM)

- Retro-fitting of additional fields in ESP/ replacement of ESP etc. required to achieve the proposed norms in existing plants.
- There may be space constraints in modification in ESP area in the existing plants. A capacity of around 60 GW (302 Units) may have such space problems while retrofitting equipment to meet revised environmental norms.

SULPHUR DIOXIDE (SO_x)

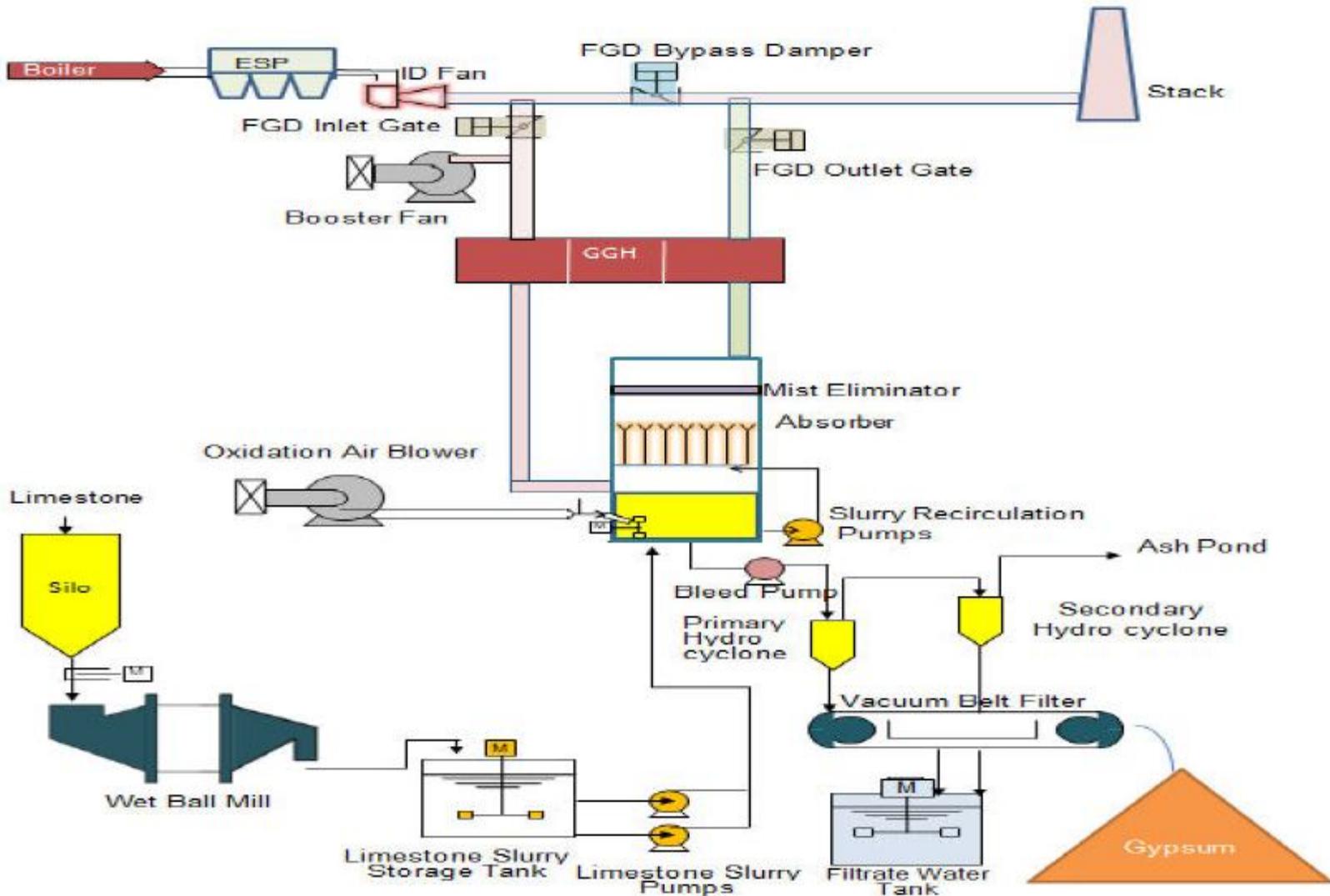
- FGD system would need to be installed to meet the amended norms regarding SO_x control for all categories of existing plants as well as plants under construction.
- Units of less than 500 MW size and some older 500 MW units face layout problems for installation of FGD system due to non-availability of space. A capacity of around 90 GW (430 units) is facing problem due to non-availability of space for FGD.
- A capacity of around 90 GW (151 units) of existing plants and 72 GW (73 units) of plants under construction would require installation of FGD plant.

MAJOR TECHNICAL ISSUES FOR THERMAL PLANTS

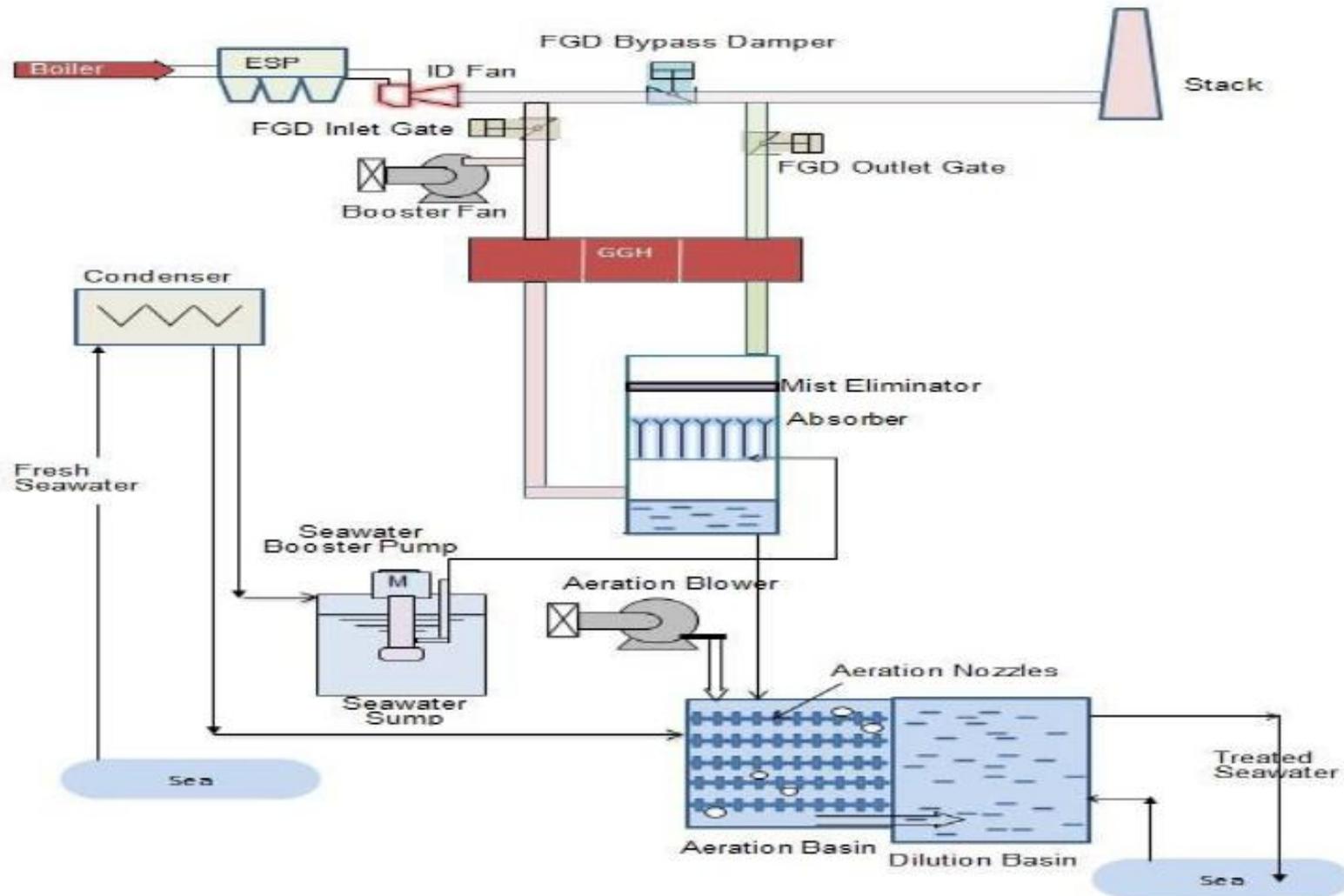
OXIDES OF NITROGEN (NO_x)

- The proposed standards of 600 mg/Nm³ (302 existing units) would require modification of the combustion process using low NO_x burners.
- The proposed standards of 300 mg/Nm³ and 100 mg/Nm³ would require installation of de-nitrification systems like Selective Catalytic Reduction(SCR) systems.
- Lay –out issues for installation of DeNO_x system in the existing units.
- The globally available SCR system for NO_x control are not proven for Indian coal having high ash contents.
- A pilot project for demo at 500 MW unit with SCR system would have to be installed to ascertain its efficacy in removal of NO_x emissions with domestic coal having high as content of the order of 40%.
- A capacity of around 120 GW (279 units) of existing plants and 72 GW (73 units) of under construction plants may require installation of SCR systems to meet new norms.

Wet lime/limestone FGD



Sea Water FGD



Total Installed Capacity (As on 31.08.2017) - Source : Central Electricity Authority (CEA)

Upcoming environmental norms for Thermal Power Plants (TPPs) in India.

In the first half of 2015, the Ministry of Environment, Forest and Climate Change (MoEFCC) issued drafts of stricter norms for emissions and water consumption for coal-based thermal power sector.

According to the new standards, shown below, thermal power plants are expected to cut emissions and usage of water measurably. It is not clear what the penalties for failure might be, especially in the short-run (while plants are scrambling to improve their technology).

Total Installed Capacity (As on 31.08.2017) - **Source : Central Electricity Authority (CEA)**

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Total Installed Capacity (As on 31.08.2017) - Source : Central Electricity Authority (CEA)

	Existing (prior) Standards	TPPs installed till Dec 31, 2003	TPPs installed between Jan 1, 2004 and Dec 31, 2016	TPPs to be installed from January 1, 2017
Sulphur Dioxide	No standard	600 mg/Nm ³ (for units < 500 MW) 200 mg/Nm ³ (for units ≥ 500 MW)	600 mg/Nm ³ (for units < 500 MW) 200 mg/Nm ³ (for units ≥ 500 MW)	100 mg/Nm ³
Oxides of Nitrogen (NO_x)	No standard	600 mg/Nm ³	300 mg/Nm ³	100 mg/Nm ³
Mercury	No standard	0.03 mg/Nm ³ (for units ≥ 500 MW)	0.03 mg/Nm ³	0.03 mg/Nm ³
Particulate Matter (PM)	150-350 mg/NM ³	100 mg/Nm ³	50 mg/Nm ³	30 mg/Nm ³
Water Consumption	not available	3.5 m ³ /MWh	3.5 m ³ /MWh	2.5 m ³ /MWh

Source: MoEFCC, as compiled by ICRA Ltd. and CSE.

Total Installed Capacity (As on 31.08.2017) - **Source : Central Electricity Authority (CEA)**

Meeting the norms: Technologically doable, but with effort

India's planned power plant emissions norms, which were notified in late 2015, for the first time added sulfur dioxide, nitrogen oxides (NO_x), and mercury, going beyond older particulate matter (PM) norms. The norms vary by plant vintage—older plants face improved but still relatively looser norms, while newer plants will need to become comparable to global best practices. Power plants, even though they are just one of several sources of air pollution (crop burning, vehicles, construction, etc. being others), are a measurable source with only a few hundred locations to act upon, and thus a low-hanging fruit.

In principle, the norms are technologically achievable, for the most part, as they use “off-the-shelf” technology that is decades old, and should not be patent protected. However, the time frame for implementation—announced in December 2015, to go into force in December 2017—appears too aggressive and perhaps even unrealistic.

Total Installed Capacity (As on 31.08.2017) - Source : Central Electricity Authority (CEA)

Meeting the norms: Technologically doable, but with effort

Physically implementing environmental control norms includes the following steps:

- Design of solutions
- Tariff petitions
- Tendering and procurement
- Shut-down for installation (60-90 days each)

Emission Control Technologies

SPM Control	SOx Control	NOx Control
<p>SPM</p> <ul style="list-style-type: none"> -Use of large size ESP with advanced controller -Adoption of Bag Filter to remove particle below 10 micron size -Adoption of Flue gas conditioning to improve the performance of Old ESP 	<ul style="list-style-type: none"> -Use of Flue gas Desulfurisation (FGD) -In bed sulfur capture in AFBC/CFBC/PFBC 	<ul style="list-style-type: none"> •Combustion <u>Control</u> <ul style="list-style-type: none"> - Low NOx burner - Overfire Air •Post Combustion Treatment <ul style="list-style-type: none"> - Selective Catalytic Reduction (SCR) - Selective Non Catalytic Reduction (SNCR)



Emission Controls

Clean Coal Technology

Trends in Power Plant Engineering

Efficiency Improvement

- Sub Critical Cycle
- Super Critical Cycle
- Ultra Supercritical Cycle

Emission Control

- Particulate
- Sox (FGD)
- Nox

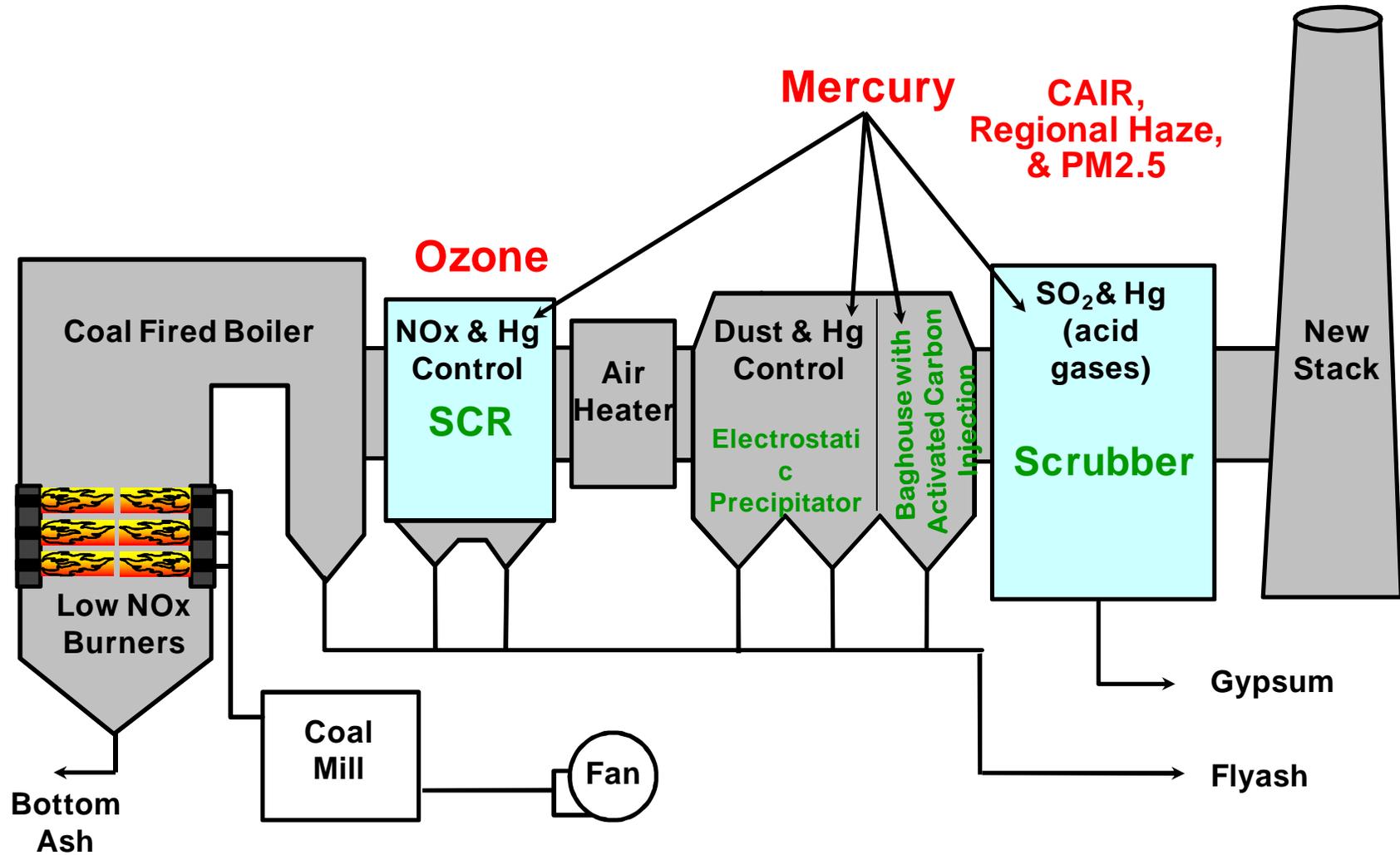
Alternate Fuels/ In situ control

- CFBC/ BFBC

Technology Development

- IGCC
- Oxy Combustion
- CO₂ Separation

Emission Controls



HOW NO_x IS FORMED

- ✓ NO_x is a high-temperature byproduct of the combustion of fuels with air
- ✓ NO_x formation in flames has two principal sources
 1. Thermal NO_x is that fraction of total NO_x that results from the high-temperature reaction between the nitrogen and oxygen in the combustion air
 - The rate of thermal NO_x formation varies exponentially with peak combustion temperature and oxygen concentration
 - When low-nitrogen fuels such as natural gas, higher grade fuel oils, and some nonfossil fuels are used, nearly all the NO_x generated is thermal No_x
 - Fuel NO_x is that fraction of total NO_x that results from the Conversion of organic-bound nitrogen in the fuel to NO_x
 - When coal, low-grade fuel oils, and some organic wastes are burned, fuel NO_x generally becomes more of a factor because of the higher levels of fuel-bound nitrogen available

PARAMETERS AFFECTING NO_x

Principal among these are:

- ✓ The heat release rates and absorption profiles in the furnace
- ✓ Fuel feed mechanisms
- ✓ Combustion air distribution
- ✓ Boiler operating loads

For example, steam pressure and temperature requirements may mandate a certain heat release rate and heat absorption profile in the furnace which changes with the load of the boiler.

- ✓ Solid fuels can be introduced into the furnace in several ways, each influencing the rate of mixing with combustion air and the peak combustion temperature
- ✓ These parameters are very unit specific and vary according to the design type and application of each individual boiler
- ✓ NO_x emissions from boilers tend to be highly variable.

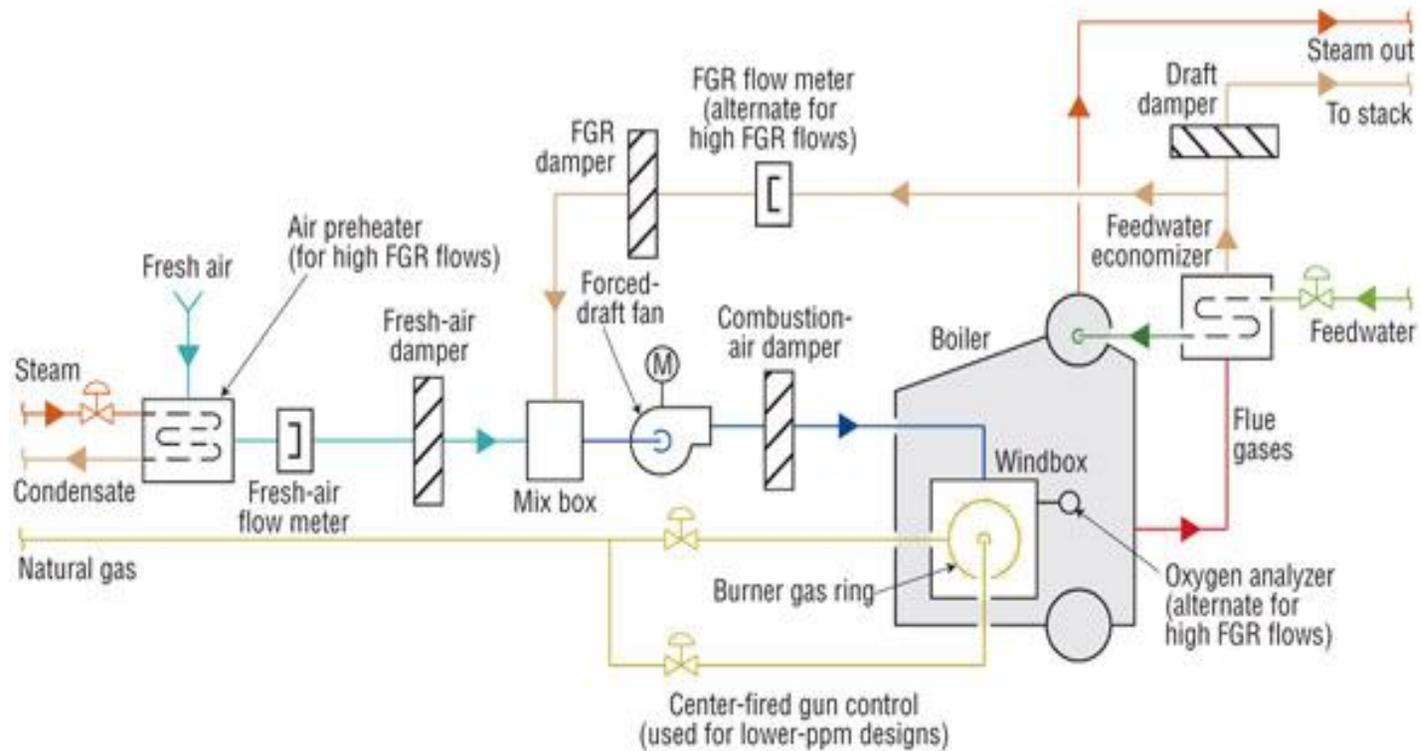
Nox Control

- ✓ Retrofitting existing generating units with low-NO_x burners is the most frequently chosen compliance control because it is an economical way to limit the formation of NO_x
- ✓ Low-NO_x burners control fuel and air mixing to create larger and more branched flames, reduce peak flame temperatures and lower the amount NO_x formed
- ✓ The improved flame structure also improves burner efficiency by reducing the amount of oxygen available in the hottest part of the flame
In principle, there are three stages in a conventional low-NO_x burner:
 1. Combustion - combustion occurs in a fuel-rich, oxygen-deficient zone where the NO_x is formed
 2. Reduction - where hydrocarbons are formed and react with the already formed NO_x
 3. Burnout - internal air staging completes the combustion. Additional NO_x formation occurs in the third stage, but it can be minimized by an air-lean environment
- ✓ Low-NO_x burners can also be combined with overfire air technologies to reduce NO_x further

Nox Control

- ✓ Other air pollution emissions that are a concern when NO_x controls are applied to boilers are: ammonia (NH₃) and nitrous oxide (NO), unburned hydrocarbon (HC), particulate matter (PM), and air toxic emissions
- ✓ Ammonia and NO emissions are associated with the use of the Selective Non-Catalytic Reduction (SNCR) controls and with Selective Catalytic Reduction controls to a lesser extent. With either urea or ammonia hydroxide, unreacted ammonia emissions escape the SNCR temperature window resulting in direct emissions to the atmosphere

Nox Control



Typical low-NO_x induced FGR flow for industrial-style boiler

Combustion Modification Options

One feature that distinguishes NO_x control from SO₂ or particulate control is the unique opportunity to achieve it at the source. NO_x formation is a complex process, primarily dependent on oxygen availability and temperature during combustion. In general, lower oxygen levels and lower peak flame temperatures lead to reduced NO_x formation from fuel-bound and atmospheric nitrogen. Exploiting these phenomena is the basis for NO_x control through combustion modifications in which favorable conditions are created through changes in furnace design and operations.

Operational modifications. These include low excess air (LEA) operation, which reduces overall oxygen availability in the furnace (a requirement of any low-NO_x system); biased firing, which generates alternate fuel-rich and fuellean zones by changing the air and fuel flow rates of individual burners; and burners-out-of-service (BOOS), in which fuel is eliminated from the air stream feeding selected burners. Cumulatively, these operational modifications can reduce NO_x formation by 10-30 percent.

Combustion Modification Options

Over-fire air. OFA involves the addition of air injection ports above the uppermost burners in the furnace. In operation, a portion of combustion air, typically less than 25 percent, is diverted to the ports, creating a slightly fuelrich primary burning zone and an air blanket where combustion is completed.

An OFA retrofit requires furnace penetrations and new ductwork, and assumes that ample space is available above the burners for combustion to be completed. NOX reduction potential with OFA alone ranges up to 30 percent.

Low-NOx burners. Low-NOx burners control the mixing of fuel and air entering the furnace, thereby creating conditions favorable to low NOX production. These burners can reduce NOX emissions by 40-60 percent at costs only slightly greater than operational modifications and/or OFA.

Combustion Modification Options

Low-NO_x burners. As a result, on a dollar-per-ton of- NO_x-removed basis, low-NO_x burners appear at present to be the most cost-effective option for utilities, where applicable. Low-NO_x burners can be used in combination with overfire air or reburning to achieve up to 75 percent NO_x reductions.

Reburning (or in-furnace NO_x reduction). With reburning, 10-20 percent of the fuel is injected above the burners to generate a fuel-rich secondary combustion zone—a chemical-reducing environment where NO_x produced in the primary combustion zone is destroyed. Because residence time for fuel introduced into the upper furnace cavity is relatively short, an alternative, fast-burning fuel such as oil or gas may be preferable for secondary combustion in some applications. Reburning is the most complicated approach to combustion modification, requiring extensive changes to the boiler and firing system.

Postcombustion Treatment

Selective catalytic reduction, which was first developed and implemented in Japan, has become almost synonymous with the concept of postcombustion NO_x control. It converts NO_x to elemental N₂ and H₂O using ammonia as a reducing agent in the presence of a catalyst at temperatures between 500 and 700° F. The ammonia is injected into the flue gas upstream of a catalyst bed usually located between the economizer and air heater. Using SCR under optimum conditions to treat flue gas from low-sulfur coal, NO_x reduction of up to 80 percent has been demonstrated.

Capital costs for SCR on new power plants can range up to \$50-100/kW—5-10 times as high as those for low-NO_x burners—and estimated operating costs are 8-14 mills/kWh and are highly dependent on achievable catalyst life. SCR retrofits may incur additional capital costs.

Post-combustion Treatment

In SCR operation, problems can arise when "slip" (unreacted) ammonia reacts with SO_3 in the flue gas to form ammonium sulfates which precipitate onto downstream equipment, causing pluggage and corrosion. This represents a particular problem with flue gas from the high-sulfur coal burned in many U.S. plants because the SCR catalyst encourages oxidation of SO_2 to SO_3 , which in turn combines with slip ammonia to form sulfate deposits on heat transfer surfaces. Other issues relative to SCR operation include catalyst replacement frequency, spent catalyst disposal (many catalysts contain vanadium compounds, potentially categorized as hazardous), the effect on plant turndown and load following capability, and contamination of solid wastes (such as fly ash) with ammonia by-products that can make solid waste utilization or disposal more difficult and expensive.



Nox Control

Post-combustion Treatment

Nitrogen oxides (NO_x) are gaseous pollutants that are primarily formed through combustion process. While flue gas is within the combustion unit, about 95% of the NO_x exists in the form of nitric oxide (NO). The balance is nitrogen dioxide (NO₂), which is unstable at high temperatures. Once the flue gas is emitted into the atmosphere, most of the NO_x is ultimately converted to NO₂.

NO_x in the atmosphere reacts in the presence of sunlight to form ozone (O₃), one of the criteria pollutants for which health-based National Ambient Air Quality Standards have been established. Since ozone formation requires sunlight and high temperatures, ozone formation is greatest in summer months.

NO_x is generated in one of three forms; fuel NO_x, thermal NO_x, and prompt NO_x. Fuel NO_x is produced by oxidation of nitrogen in the fuel source.

Post-combustion Treatment

Combustion of fuels with high nitrogen content such as coal and residual oils produces greater amounts of NO_x than those with low nitrogen content such as distillate oil and natural gas. Thermal NO_x is formed by the fixation of molecular nitrogen and oxygen at temperatures greater than 3600° F (2000° C). Prompt NO_x forms from the oxidation of hydrocarbon radicals near the combustion flame and produces an insignificant amount of NO_x.

Selective Noncatalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NO_x) into molecular nitrogen (N₂) and water vapor (H₂O). The primary difference between the two technologies is that SCR utilizes a catalyst to increase the NO_x removal efficiency, which allows the process to occur at lower temperatures. The technologies can be used separately or in combination with other NO_x combustion control technologies such as low NO_x burners (LNB) and natural gas reburn (NGR). SNCR and SCR can be designed to provide NO_x reductions year-round or only during summer months, when ozone concerns are greatest.

Post-combustion Treatment

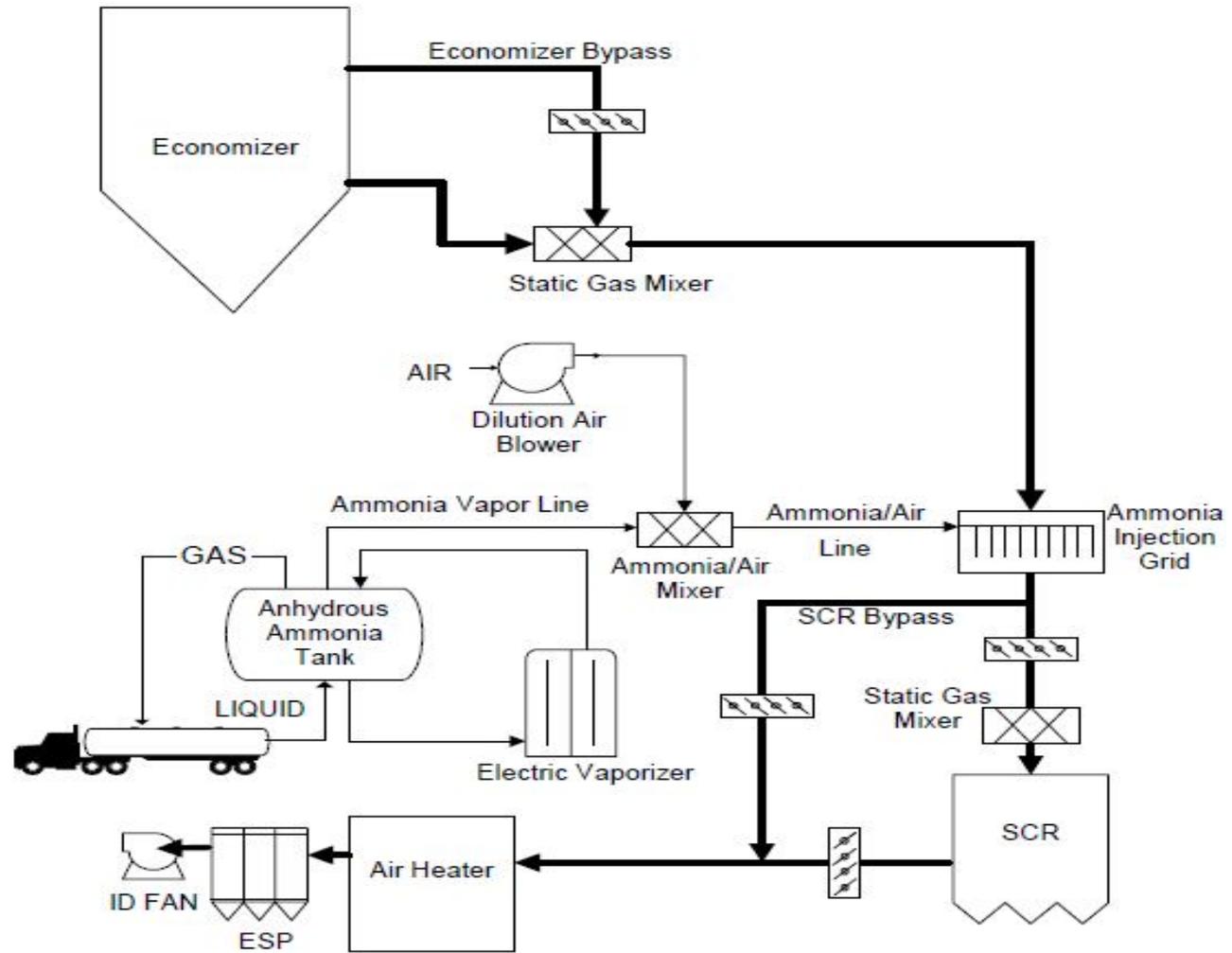
Like SNCR, the SCR process is based on the chemical reduction of the NO_x molecule. The primary difference between SNCR and SCR is that SCR employs a metal-based catalyst with activated sites to increase the rate of the reduction reaction. A nitrogen based reducing agent (reagent), such as ammonia or urea, is injected into the post combustion flue gas. The reagent reacts selectively with the flue gas NO_x within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_x into molecular nitrogen (N₂) and water vapor (H₂O).

The use of a catalyst results in two primary advantages of the SCR process over SNCR. The main advantage is the higher NO_x reduction efficiency. In addition, SCR reactions occur within a lower and broader temperature range. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs.

The cost increase is mainly due to the large volumes of catalyst required for the reduction reaction.

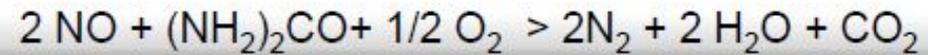
Nox Control

SCR Process Flow Diagram



BASICS OF NO_x- REDUCTION (I)

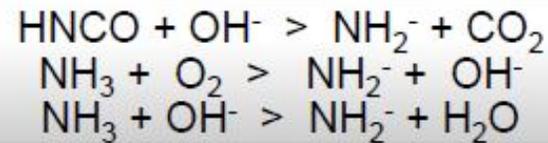
OVERALL REACTION WITH UREA



DECOMPOSITION



RADICAL FORMATION



DEGRADATIVE REACTION



BASICS OF NO_x- REDUCTION (II)

Undesired Reactions / Parallel Reactions

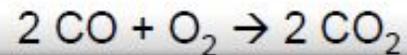
NH₃ Oxidation



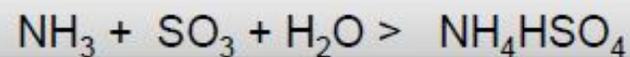
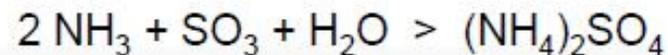
NO_x-Formation



CO Oxidation



Ammonia Sulfate & Ammonia Hydrogen Sulfate Formation



SCR Performance Parameters

The rate of the reduction reaction determines the amount of NO_x removed from the flue gas. The major design and operational factors that affect the NO_x removal performance of SCR are similar to those as for SNCR. The factors for SNCR include the following:

- Reaction temperature range;
- Residence time available in the optimum temperature range;
- Degree of mixing between the injected reagent and the combustion gases;
- Molar ratio of injected reagent to uncontrolled NO_x;
- Uncontrolled NO_x concentration level; and
- Ammonia slip.

Additional design and operational factors to consider, which are specific to the SCR process, include:

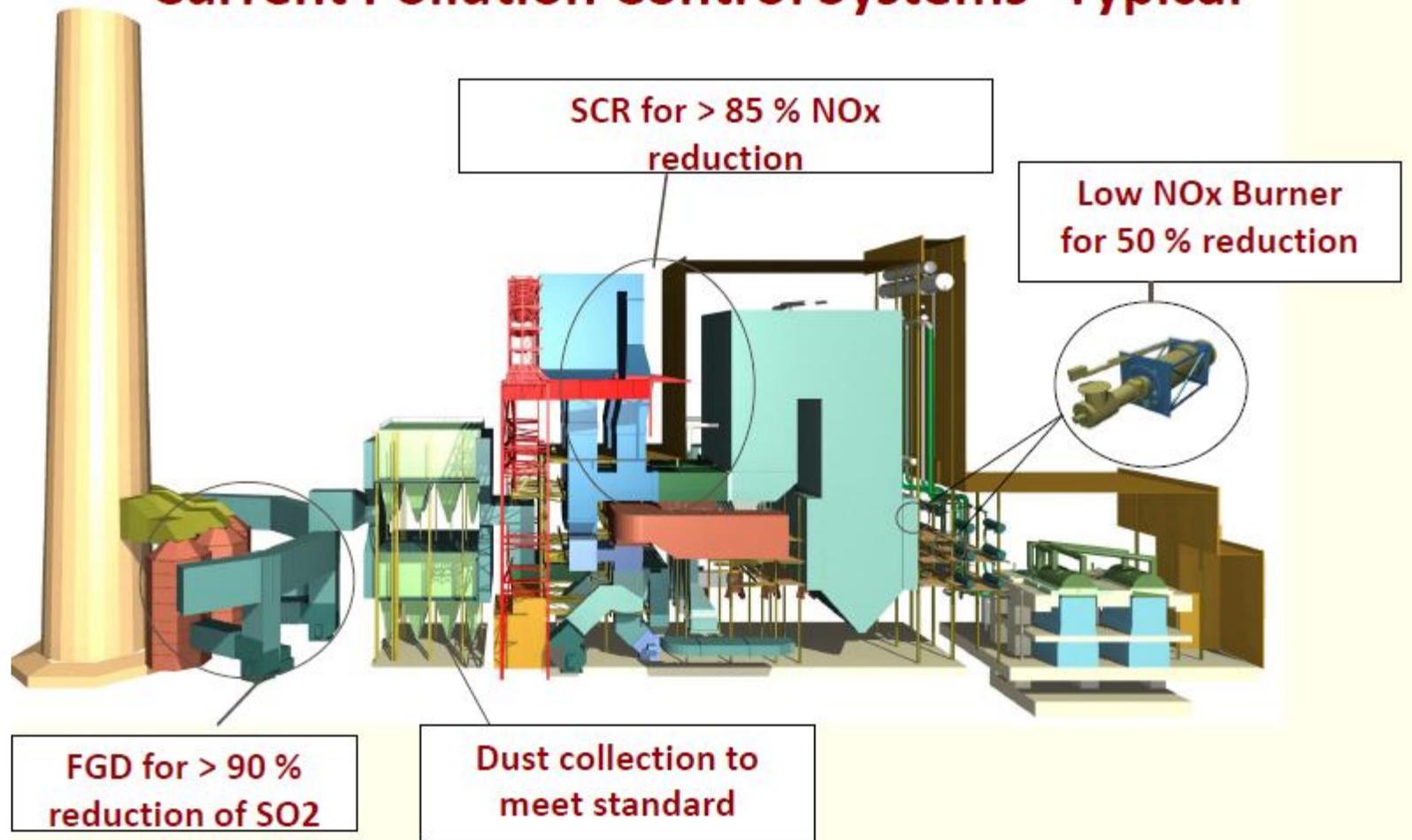
- Catalyst activity
- Catalyst selectivity

SCR Performance Parameters

- Pressure drop across the catalyst
- Catalyst pitch
- Catalyst deactivation
- Catalyst management

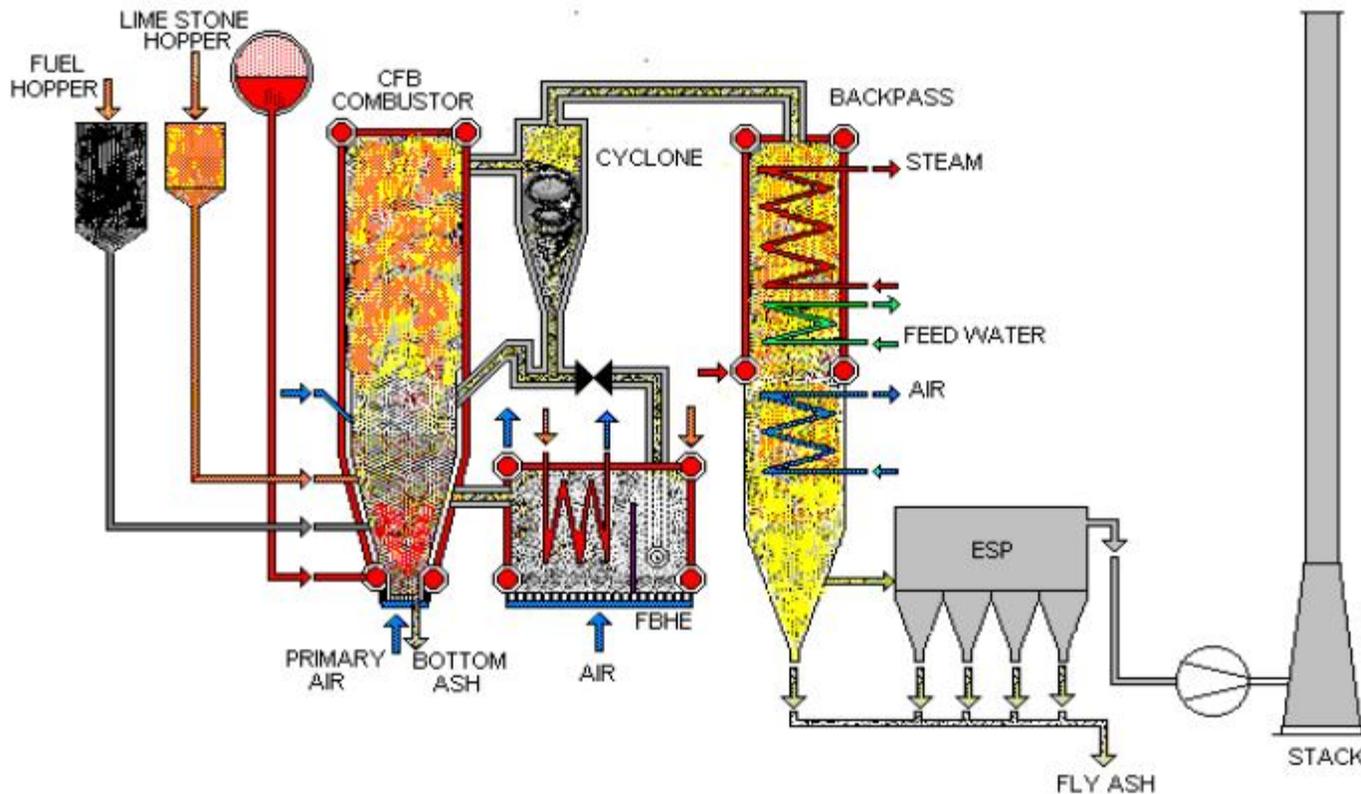
Emission Controls

Current Pollution Control Systems- Typical



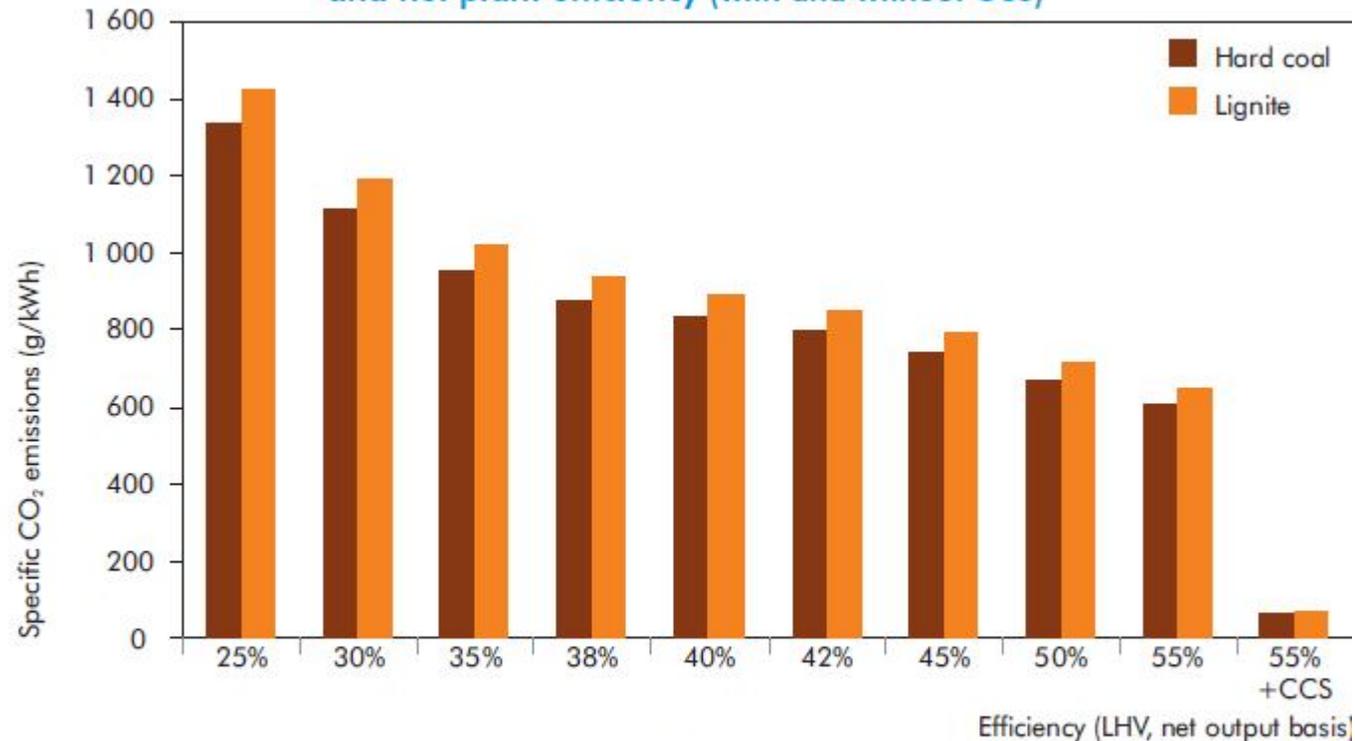
Emission Controls

BASIC FLOW DIAGRAM OF A CIRCULATING FLUIDIZED - BED COMBUSTION BOILER (CFBC)



Conclusions

Figure 2.8: Example of relationship between CO₂ emissions and net plant efficiency (with and without CCS)

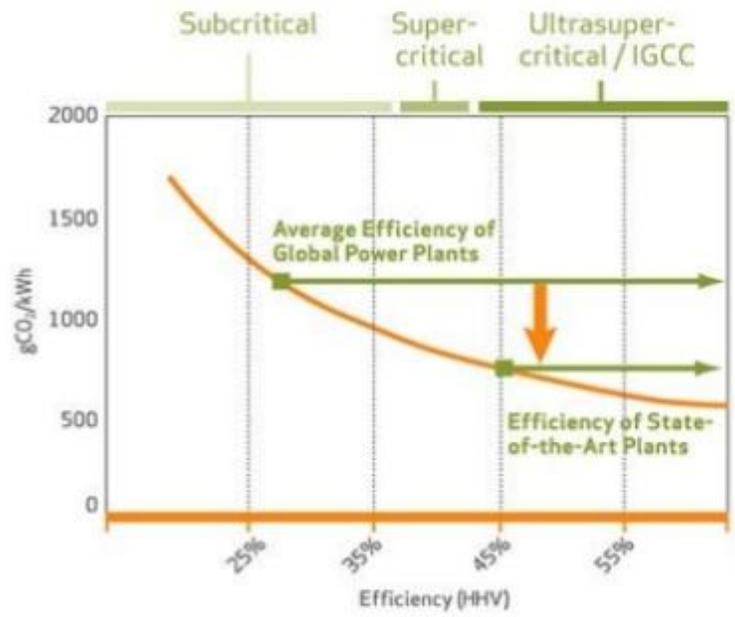


Note: Specific CO₂ emissions are calculated here using IPCC default emission factors for stationary combustion in the energy industries: 94.6 kgCO₂/GJ for bituminous coal used for power generation and 101.0 kgCO₂/GJ for lignite (IPCC, 2006). It is assumed that 98% of the fuel carbon is oxidised, the remaining 2% being retained in ash, although this varies in practice (IPCC, 1996). For the case shown with CCS, a CO₂ capture rate of 90% is assumed.

Source: IEA analysis.

Conclusions

Emission Control in Boiler Designs Reduction of CO₂ Emissions by Improving the Efficiency of Coal-fired Power Plants



Source: IEA "Focus on Clean Coal" (2006)
 Note: 1% increase in efficiency = 2-3% decrease in emissions

- Subcritical
 - E.g. FBC's
- Supercritical & Ultrasupercritical
 - (New) pulverized coal combustion systems
- IGCC
 - Integrated Gasification & combined cycle

Ash Mineralization for Carbon Sequestration

The background of the slide features a stylized globe with a grid of latitude and longitude lines. A large, glowing arc in shades of yellow and orange curves across the upper right portion of the globe. The overall color palette is dominated by blues, greens, and yellows.

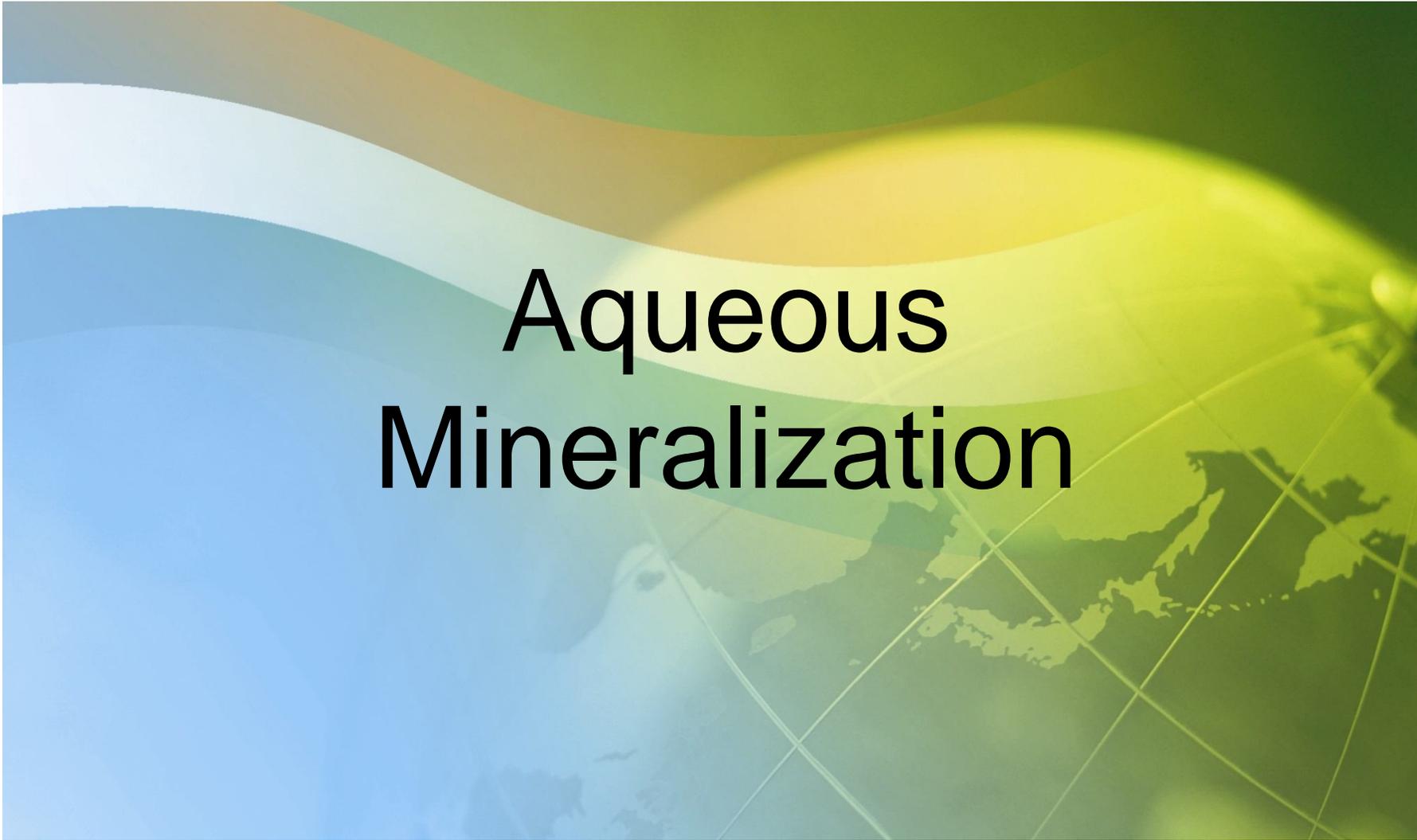
Introduction and Background

- Flue Gas: CO₂ – 12.2%, O₂ – 7%, SO₂ – 1500 mg/Nm³, NO_x – 470 mg/Nm³, Moisture 8 – 11%, SPM – 100 – 150 mg/Nm³ and rest is nitrogen & traces of heavy metals & other impurities .
- Mass of flue gas for 200 MW units is around 900 T/Hr and for 500 MW unit is around 2000 T/Hr.
- This implies approximately 0.8 – 0.9 T/MW/Hr of CO₂ - a major source of Green House Gases in the atmosphere.
- SO_x & NO_x cause acid rain and along with SPM are health hazard.
- Station A Fly ash – 4.5 to 5.0% CaO – pH of ash slurry is between 11 – 12 – Thick scaling in Ash Slurry Pipelines (20 – 30 mm thick) – Operational problems.
- Studies conducted (1985-86) on controlling pH of ash slurry by bubbling flue gas were encouraging however, as per preliminary calculations done by Engineering gave very high value of energy required for pumping flue gas

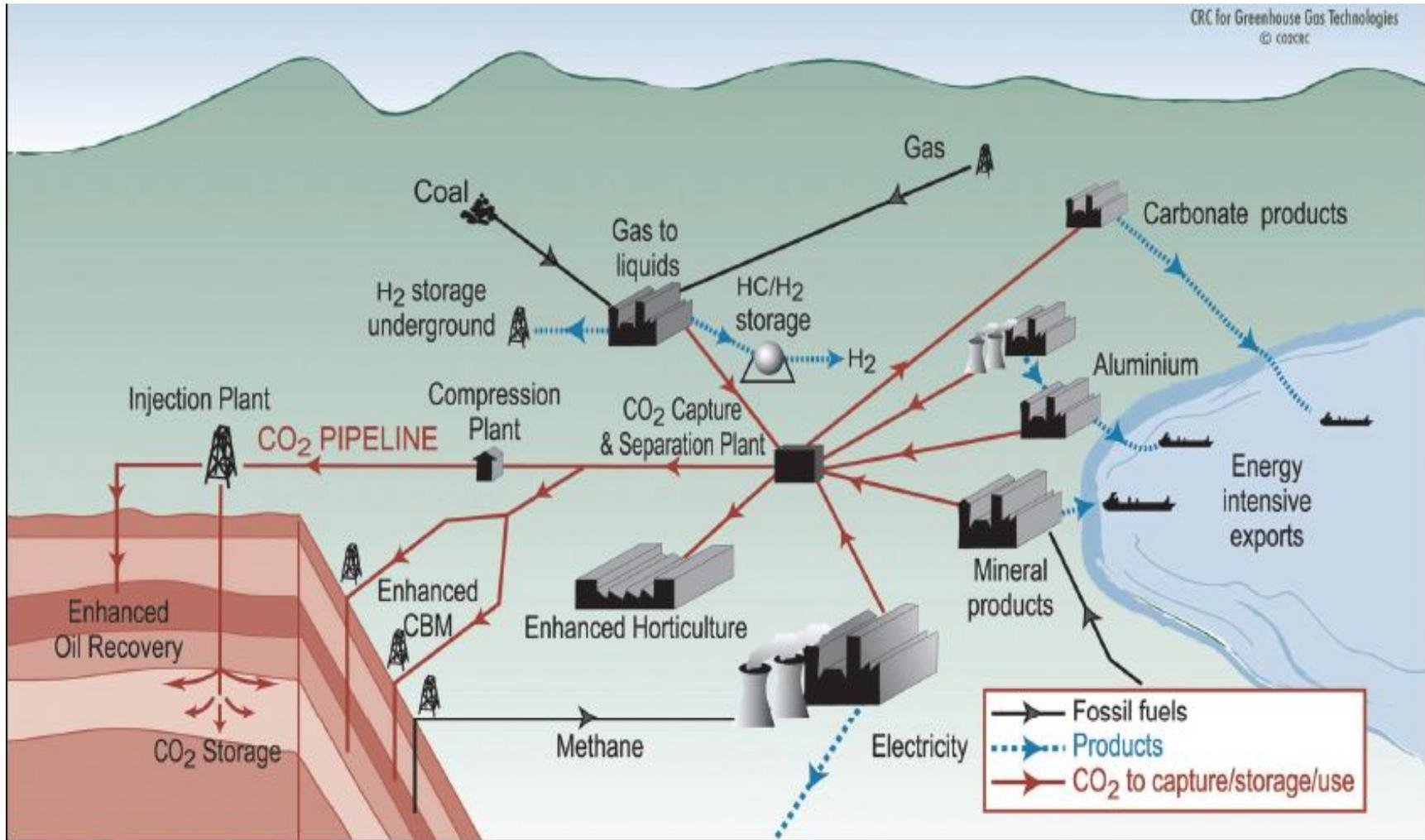
Introduction and Background

- Carbon Capture & Storage (CCS) is a subject of current International Research. Many technologies are being developed for carbon capture & utilization in either pre-combustion stage or post combustion stage.
- The mineral sequestration for the long-term storage of carbon dioxide is a CCS option that provides an alternative for the geological storage in underground cavities, especially at locations where the risk of leakage of the CO₂ stored underground is considered unacceptable, or where large resources of material suitable for carbonation are present.
- Driving forces for continued attention for this CCS route are its sheer capacity (dwarfing other CCS methods), and the fact that it gives compact and leakage-free CO₂ fixation that needs no post-storage monitoring and finally the potential of operating at a zero (or negative) net energy input, provided that the process is properly optimized, and utilizes the benefits of favourable thermodynamics.
- *Mineralization of fly ash available at power plants with plant flue gas provides an excellent opportunity for not only CCS but also reduction in overall emission from flue gases and may provide additional benefits for the plant.*

Aqueous Mineralization

The background of the slide features a stylized globe with a grid of latitude and longitude lines. A large, semi-transparent yellow and green gradient shape is overlaid on the globe, resembling a lens or a spotlight. The colors transition from a light yellow at the top to a darker green at the bottom. The text 'Aqueous Mineralization' is centered over this graphic.

Aqueous Mineralization



Probable CCS & CO₂ Fixation Technologies

Aqueous Mineralization

➤ **Geological storage:** storage of CO₂ in underground cavities, Enhanced Oil Recovery (EOR), Enhanced Gas Recovery (EGR), Enhanced Coal Bed Methane recovery (ECBM).

➤ **Ocean storage:** injecting CO₂ into the ocean, preferably at great depths, where the gaseous CO₂ reacts to form carbonic acid (H₂CO₃). The carbonic acid then dissociates into a (bi) carbonate ion and hydrogen ion in accordance with the equation below:



➤ **Storage below sea bed:** carbon dioxide storage below the ocean floor at depths of at least 3,000 m of ocean and several hundred meters of marine sediment

➤ **Mineral carbonation:** *in situ* or *ex situ* mineral carbonation. The reaction between a metal oxide bearing material and CO₂ is called carbonation and can be expressed by the following reaction:



Aqueous Mineralization

Mineral carbonation:

- One major benefit of CO₂ sequestration by mineral carbonation consist of the environmentally benign and virtually permanent trapping of CO₂ in the form of carbonated minerals by using abundant mineral resources such as Mg-silicates.
- This option is the only CO₂ sequestration option available where large underground reservoirs do not exist and ocean storage of CO₂ is not feasible.
- Another benefit of mineral carbonation is that, at least theoretically, the carbonation process could proceed without energy input.
- The largest challenge has perhaps been, and still is, to enhance the otherwise extremely slow (hundred thousands of years in nature) carbonation reaction, without excessive overall process costs.

Aqueous Mineralization

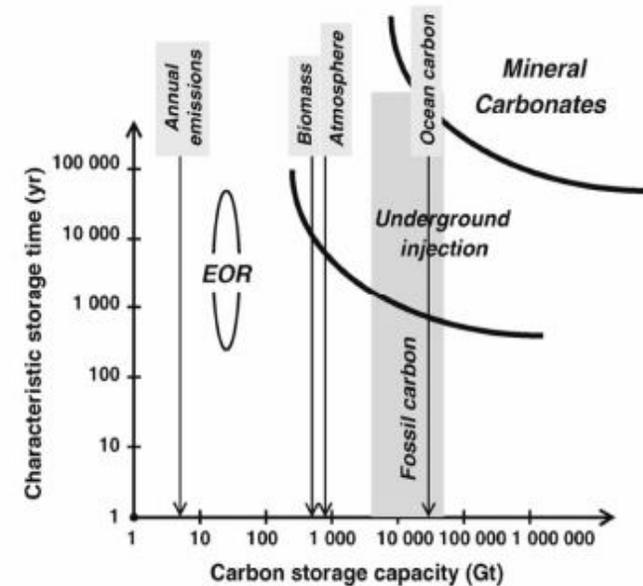
Mineral carbonation:

- Another factor to consider is that large-scale sequestration of CO₂ from flue gases as mineral carbonates will require vast amounts of mineral: 1 kg of CO₂ may require 2 kg (or more) of serpentine for disposal, which certainly results in significant environmental impact at the disposal site.
- On the other hand, a process for storing several MT of CO₂ per annum will involve solids handling of a scale similar to a typical metal ore or mineral mining and processing.
- Materials studied for mineralization include blast furnace slag, brine, CFBC ash, Electric arc furnace slag, lignite fly ash, MSW bottom ash, PFA, waste cement, etc.

Aqueous Mineralization

Direct aqueous carbonation:

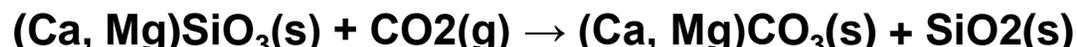
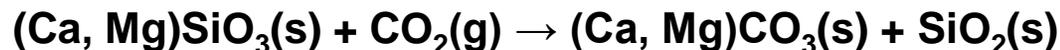
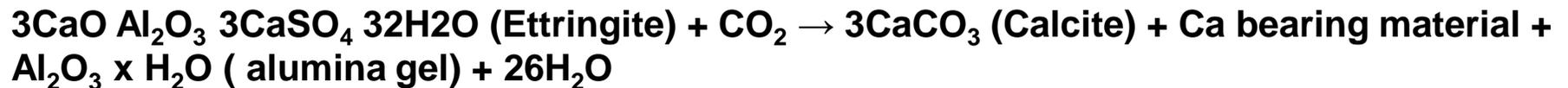
- The direct aqueous mineral carbonation-route, *i.e.* carbonation performed in a single step in an aqueous solution, appears to be the most promising CO₂ mineralization alternative to date.
- Expensive pre-treatment steps aiming at accelerating the reaction rates must be improved or bypassed in order for this process route to become competitive with other CCS technologies.
- Direct aqueous mineral carbonation can be further divided into two subcategories depending on the type of solution used. Studies focusing on carbonation in pure aqueous solutions have quickly made way for additive-enhanced carbonation experiments and a common solution type used today, consists of 0.64 M NaHCO₃ + 1.00 M NaCl.



Estimated storage times and capacities for various CO₂ sequestration methods

Mineralization of Ash Slurry by Flue Gas:

Ash is disposed off as a slurry by mixing with water. Flue gases emitted at a temperature of about 130 – 150 oC, mineralization of ash slurry may be more beneficial by direct scrubbing with flue gas. Mineralization of ash slurry by direct interaction with flue gas provides a more economical route as both the CO₂ source and ash slurry are available at same location only energy penalty involved is power to suck flue gas & pumping of ash slurry to reaction chamber. The mineralization reactions with fly ash are as indicated below:



Aqueous Mineralization

S No	Waste type	Ca content	Mg content	Amount of utilized CO ₂
		[g/kg]	[g/kg]	[g/kg]
1	Cement waste	424.7-448.8	9.0-11.0	486.1
2	Fly ash from coal combustion	38.1	9.2	58.6
3	Fly ash at Station X, Fly ash composition data	48.3 as CaO	12.5 as MgO	51.7
4	Fly ash from community waste combustion	119.1	13.5	155.2
5	Blast furnace slag	222.0-312.5	45.0-73.1	325.2-407.1

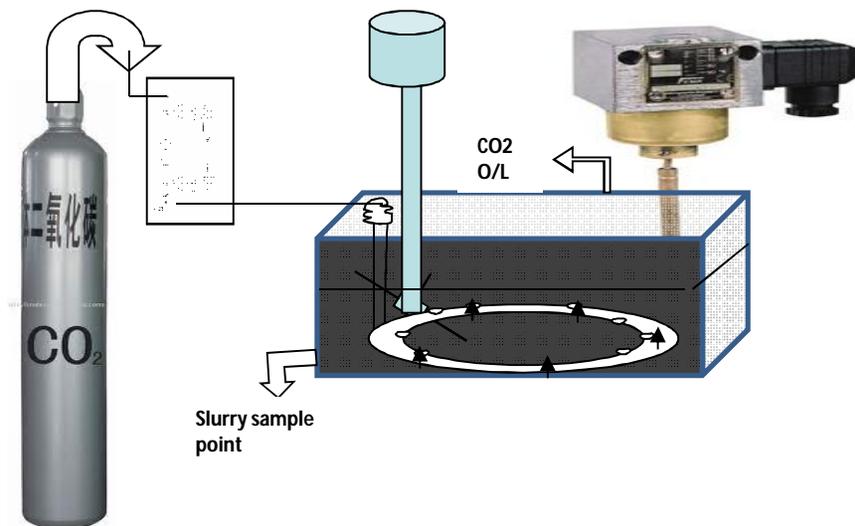
CO₂ potential for sequestration for some mineral waste



Experimental Studies and Data

LAB SCALE STUDIES:

Initial studies conducted in lab by fabricating a set up and preparing ash slurry from two stations fly ash and CO₂ from cylinder.

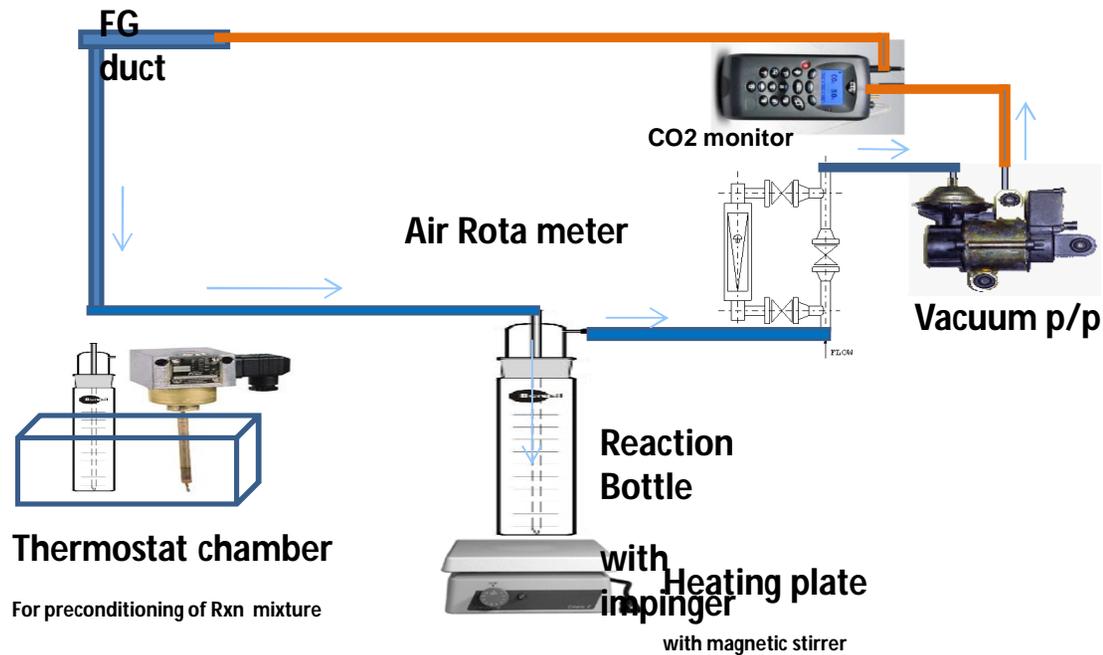


Scheme and Experimental set up for aqueous mineralization of fly ash

Experimental Studies & Data

Small scale studies at Station B:

The lab study results were found satisfactory and on the basis of lab study data further test setup were installed at Station B using Station B fly ash (with lime) and Station A fly ash.



Scheme and Experimental set up for aqueous mineralization of fly ash

Experimental Studies & Data

Small Scale studies at Station A:

Test set up similar to Station B was installed at Station A and different studies have been conducted with fly ash slurry, bottom ash slurry and ash pond overflow as follows:

Sample Vol.	FG Flow Volume	Temp.	CO2 Measured at Inlet	CO2 Measured at outlet	
1 Liter	liters	(°C)	(Max. %)	(Min.%)	
Flue gas volume optimization					
Fly Ash Slurry (13%)	30	50			
Fly Ash Slurry -Actual (15-16%)	60	50	9.5	6.3	
Bottom Ash Slurry - Actual	10	50			
Ash Pond Overflow(APO)	3	50	-	-	
Variable flow rates	Optimized flow = 1 lpm				

Experimental Studies & Data



Experimental Set up at Station A

Experimental Studies & Data

With pure CO2 injection	pH	K	CaH as CaCO3	TH as CaCO3	p-alk as CaCO3	m-alk as CaCO3	CO2 Absorbed in slurry
(Temp 60°C)		μS/cm	ppm	ppm	ppm	ppm	mg per litre
Before	8.1	1691	84	164	0	260	-
After 120 liters CO2 passed @1 lpm for 2 Hrs	5.8	1833	92	163	0	250	-4.4

Experimental Data with Fly ash

With pure CO2 injection	pH	K	CaH as CaCO3	TH as CaCO3	p-alk as CaCO3	m-alk as CaCO3	CO2 Absorbed in slurry
(Temp 60°C)		μS/cm	ppm	ppm	ppm	ppm	mg per litre
Before	9.20	1834	340	392	16	208	-
After 120 liters CO2 passed @1 lpm for 2 Hrs	8.0	2190	568	600	0	408	88

Experimental data with Ramagundam fly ash

Experimental Studies & Data

Sl. No.	PARAMETERS	units	Before passing CO ₂	After passing CO ₂
1	pH	-	10.4	8.45
2	Conductivity	μS/cm	2440	725
3	Salinity	%	1.2	0.3
4	TDS	mg/l	1210	347
5	Chloride as CaCO ₃	mg/l	68	34
6	P.Alk as CaCO ₃	mg/l	408	16
7	M.Alk as CaCO ₃	mg/l	428	176
8	T-H as CaCO ₃	mg/l	520	320
9	Ca-H CaCO ₃	mg/l	504	240
10	Sulphate as SO ₄	ppm	74	119
11	Mass of 50 ml ash slurry	gm	49.1568	49.3064

Variation in chemical parameters before & after passing flue gas in ash slurry

Experimental Studies & Data

Treatment with flue gas at Dadri	pH	K	CaH as CaCO ₃	TH as CaCO ₃	p-alk as CaCO ₃	m-alk as CaCO ₃	CO ₂ Absorbed in slurry
		μS/cm	ppm	ppm	ppm	ppm	mg per litre
Before	11.2	1091	326	330	160	180	-
After 60 liter FG passed vol@2 lpm	7.0	815	260	338	0	292	110.88

Chemical Analysis of Ash Slurry with 4.5% lime

Treatment with flue gas of Ramagundam	pH	K	CaH as CaCO ₃	TH as CaCO ₃	p-alk as CaCO ₃	m-alk as CaCO ₃	CO ₂ Absorbed in slurry
		μS/cm	ppm	ppm	ppm	ppm	mg per litre
Before	12.3	6050	1552	1560	1348	1388	-
After 60 liter FG passed vol@2 lpm	7.84	1890	876	965	0	364	125

Chemical Analysis of Actual Ramagundam Ash Slurry

Experimental Studies & Data

Volume of Flue Gas Lit	CO ₂ %	NOX mg/m ³	SO ₂ mg/m ³
0	9.5	523	825
1	9.3	523	421
6	6.3	529	0
10	6.9	529	0
12	7.2	525	0
14	7.5	523	0
20	7.7	513	0
30	7.8	515	0
36	8.2	502	0
38	8.4	502	0
44	9.2	492	0
46	9.4	490	0

Variations in Flue Gas Composition after reaction with ash slurry

Experimental Studies & Data

S. No.	Parameters	Flue gas composition (%)
1	CO ₂	12.24 %
2	O ₂	7.0 %
3	NO _x	472 mg/Nm ³
4	SO _x	1520 mg/Nm ³

Flue Gas Composition at Station A

S. No.	Parameters	Fly ash composition (%)
1	LOI	0.63
2	SiO ₂	60.11
3	Al ₂ O ₃	26.55
4	Fe ₂ O ₃	5.84
5	CaO	4.83
6	MgO	1.25
7	Na ₂ O	0.22
8	K ₂ O	0.75
9	SO ₃	0.35
10	Carbon	0.36

Fly ash Composition at Ramagundam

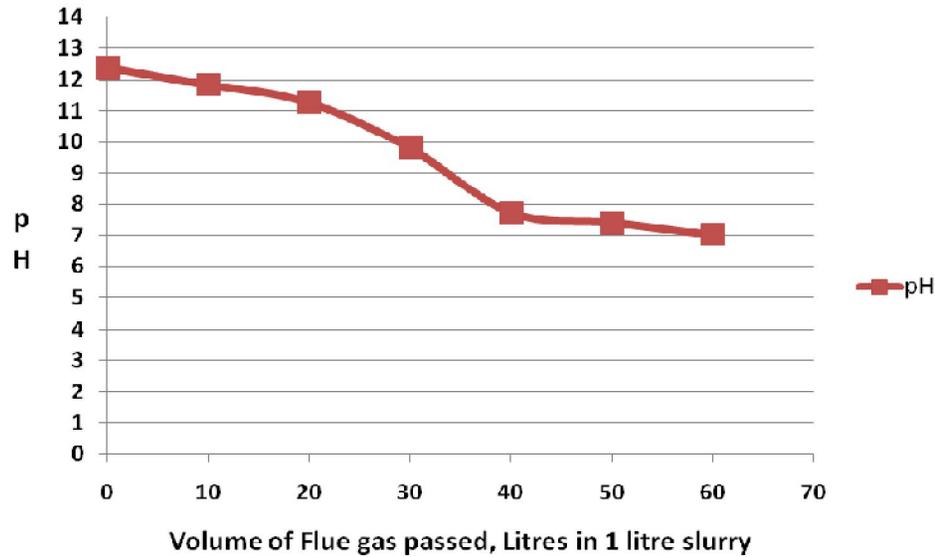
Experimental Studies & Data

S. No.	Elements	CONCENTRATIONS (%)	
		(Before FG injection)	(After 60 Ltr FG injection)
1	SiO ₂	66.1	62.7
2	Al ₂ O ₃	22.20	22.33
3	Fe ₂ O ₃	2.84	3.25
4	TiO ₂	0.834	0.901
5	CaO	2.61	3.69
6	MgO	0.661	0.869
7	Na ₂ O	0.227	0.269
8	K ₂ O	1.02	1.21
9	SO ₃	0.215	0.175
10	P ₂ O ₅	0.132	0.155
11	MnO	0.038	0.041
12	Cl	0.123	0.157
13	Loss on Ignition	2.83	4.19
	Total	99.83	99.937

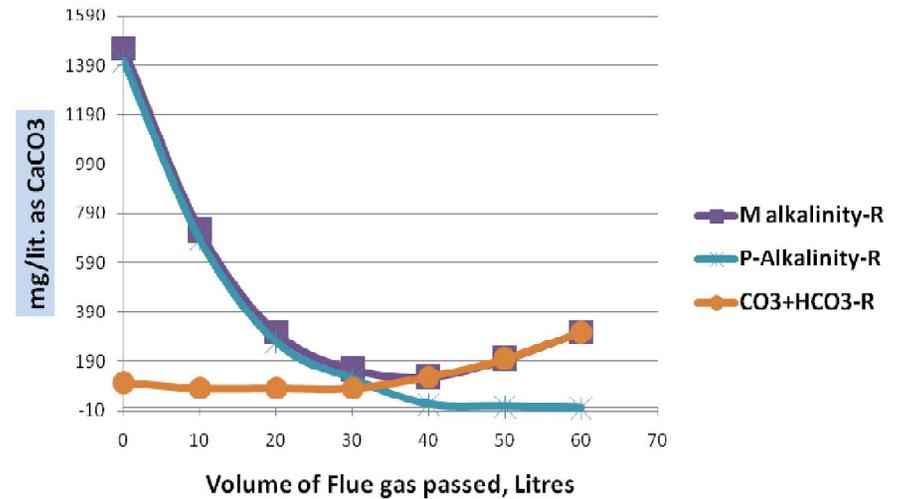
XRF analysis Fly ash Composition before & after passing flue gas at Ramagundam

Experimental Studies & Data

pH variation w.r.t. Flue Gas Volume passed at NTPC-Ramagundam

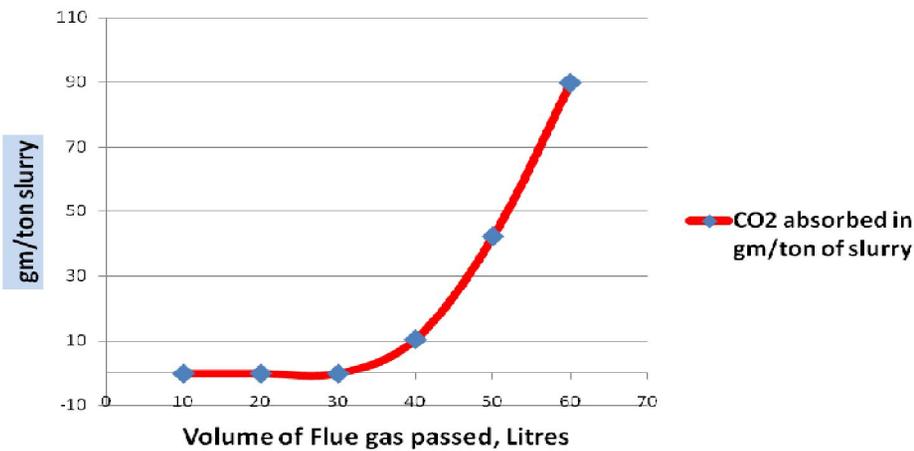


Variation in CO₃+HCO₃, P & M alkalinity w.r.t. FG Volume passed at NTPC-Ramagundam

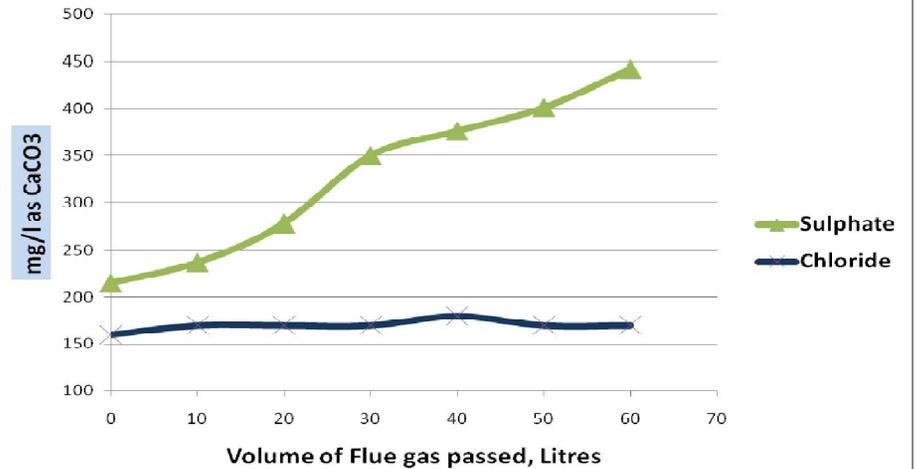


Experimental Studies & Data

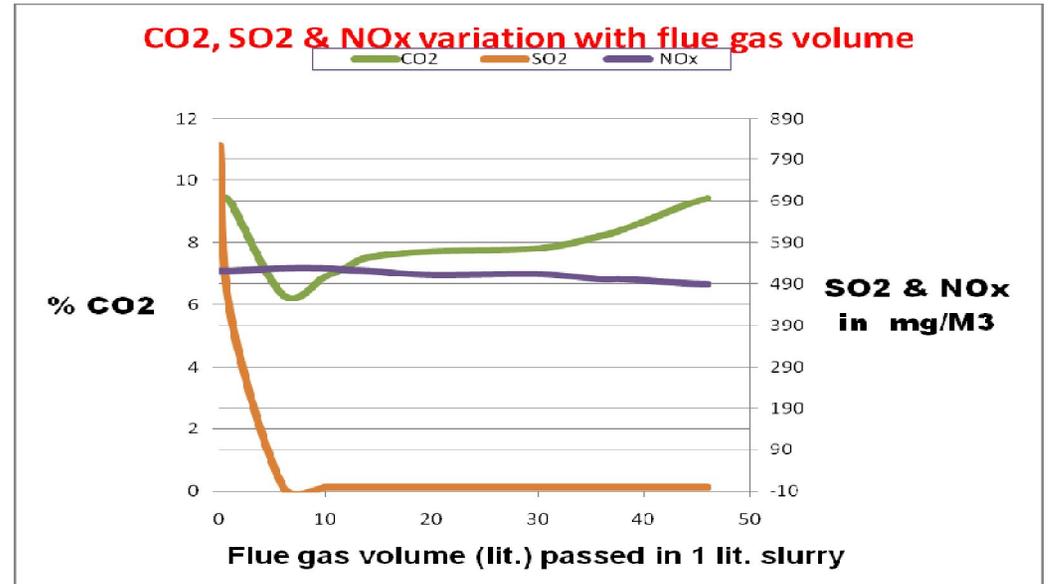
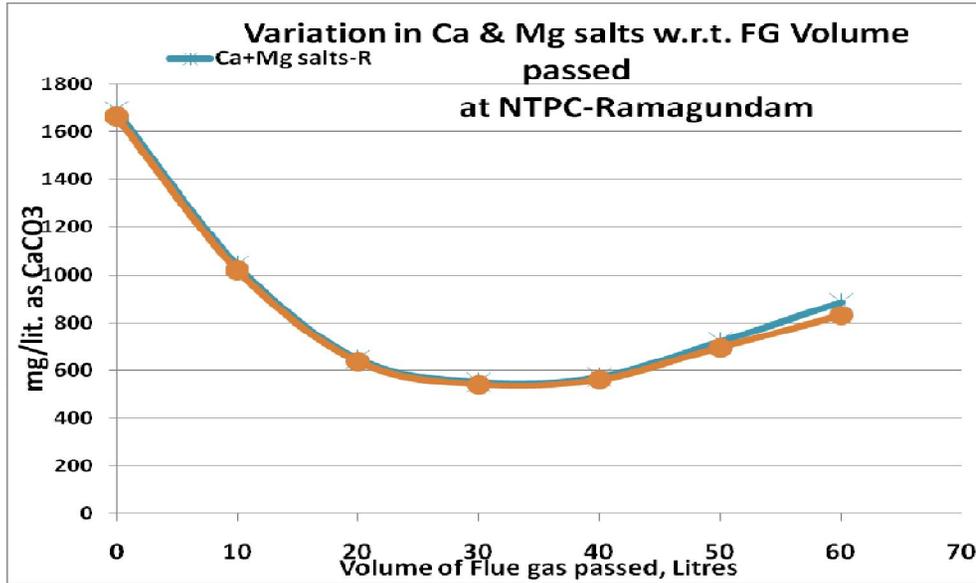
Variation in CO₂ absorbed w.r.t. FG Volume passed at NTPC-Ramagundam



Chlorides & Sulphate variation w.r.t. FG Volume passed at NTPC-Ramagundam



Experimental Studies & Data



Potential Benefits

Discussions on the Results obtained:

- Based on the data obtained following are the observations on the mineralization of fly ash by flue gas:
- In case higher than the stoichiometric amount of CO₂ is passed than the pH drops to around 7 resulting in decrease of conductivity, hardness, alkalinity and around 125 mg/lit of ash slurry is absorbed.
- In the initial reaction around 35% of CO₂ is reduced from the input level (first 5 – 6 minutes) and all the SO₂ is absorbed in the slurry. With continued reaction with flue gas further absorption of CO₂ does not take place due to which there is an increase in CO₂ content to input level. However; NO_x starts absorbing in the ash slurry.
- If the CO₂ passed is as per the stoichiometric levels than almost all parameters such as pH, conductivity, salinity, chloride, alkalinity, hardness show a decreasing trend, however; sulphates show an increased trend and overall there is a weight gain in the slurry. This is indicative of some hardness salts getting precipitated as sulphates and carbonates.

Discussions on the Results obtained (Contd.):

- In case CO_2 is passed at a level of double the stoichiometric amount than parameters such as pH, conductivity, salinity, TDS, total alkalinity, hardness, sulphate show an increasing trend. There is an overall weight gain of the slurry but is lesser compared to the weight gain in case of dosing of CO_2 at stoichiometric levels. This is indicative of some of the carbonates are converted into bicarbonates which are more soluble than carbonates so they remain in solution. This can be helpful in preventing any scale deposition in the ash slurry disposal pipelines due to high alkalinity of ash and emission reduction from flue gas, though lesser CO_2 is absorbed.
- The carbonated ash slurry settles down fast than the uncarbonated ash slurry. There is binding capacity in the carbonated ash which can help in reducing the fugitive emission from the ash pond. The carbonated ash has a potential of being transported as a paste reducing the water required for making slurry and thus saving power also in ash transportation.
- Preliminary studies show that carbonated ash when mixed with soil & manure helps in improving the plant growth by providing micronutrients for the plant & vegetation. Further studies are in progress.

CONCLUSIONS:

- On the basis of the studies conducted following can be concluded:
- 10 – 30% CO₂ can be absorbed in alkaline ash by passing flue gas in about 5 – 10 minutes of reaction time (corresponding to dissolution of stoichiometric levels of CO₂).
- Almost 100% of SO₂ is absorbed in the ash slurry.
- Any suspended particulate matter in flue gas is also trapped in the ash slurry.
- It is expected that a substantial amount of trace impurities such as mercury would also be absorbed in the ash slurry.
- In case of any scaling in the ash pipelines due to high alkalinity of the ash the same can be taken care of by increasing the flue gas quantity beyond the stoichiometric levels of CO₂.
- The settled ash will reduce the fugitive emissions from the ash pond due to binding nature of carbonated ash.
- The carbonated ash has a potential of reducing water requirement for making ash slurry and as a consequence of which auxiliary power consumption can be reduced and it can required micronutrient for plants

Potential Benefits

POTENTIAL BENEFIT OF FLY ASH MINERALIZATION BY FLUE GAS:

The studies have indicated a good amount of mineralization of fly ash and it has potential benefits such as:

- CO₂ absorption (10 – 30% from input).
- Emission reduction (100% of SO₂, 90% of SPM, considerable amount of other pollutants such as mercury from input levels).
- Minimizing the HCl consumption for controlling pH/alkalinity of ash water.
- Reduction in scaling problem in slurry lines as pH is reduced to around 7 (it is expected that scaling will be drastically reduced at this lower pH).
- Reduction in maintenance.
- Carbonated ash for agriculture use.
- Carbonated ash for infrastructure purposes.
- Possible reduction in fugitive emissions from ash pond due to binding nature of carbonated ash.
- Possible reduction in water required for making ash slurry.
- Possible reduction in power required for transportation of ash slurry (due to lesser water used).

Potential Benefits



Hardening of mineralized fly ash



Plant Growth studies on mineralized fly ash

Control of Severe Scaling in Ash Slurry Pipes:

Stage I:

Ash slurry pumps -	4 No, (3 working)
Pump Flow rate -	850 m ³ /hr
Pump rating -	165 KW
Length of Pipes -	Around 10 km
Diameter -	350 mm
Reduction in dia -	200 – 250 mm

(scaling)

Descaling - Yearly, Manually
 More scaling till about 1 km of pipe length (yearly).
 Due to scaling 4 pumps are operated instead of 3.
 Bottom ash and fly ash slurry is mixed in stage I.
 No line flushing arrangement in stage I.
 5 KW – Blower (30000 m³/hr flue gas)
 50 KW – Ash slurry pump (500 T slurry)

In stage II: Bottom & fly ash are transported separately and line flushing arrangement is there.
 Very high erosion in bottom ash lines



Potential Benefits

Calculations

Total ash slurry of Stage I	500 T/hr
1 lit. ash slurry requires flue gas	60 litres
500 T ash slurry requires flue gas	17000 m ³ /hr
Flue gas flow/unit	1000000 m ³ /hr
For treatment of 500 T ash slurry of Stage , flue gas	17000 m³/hr = 1.6% of flue gas/unit
ETP flow	5100 m ³ /hr
Acid consumed for neutralization	6 T/day
Cost of acid	Rs. 4000/T = Rs 24000/day
Flue gas required for neutralization	15300 m³/r (1.5%)

Design of Test Rig for Ash Mineralization



Flue Gas in ETP



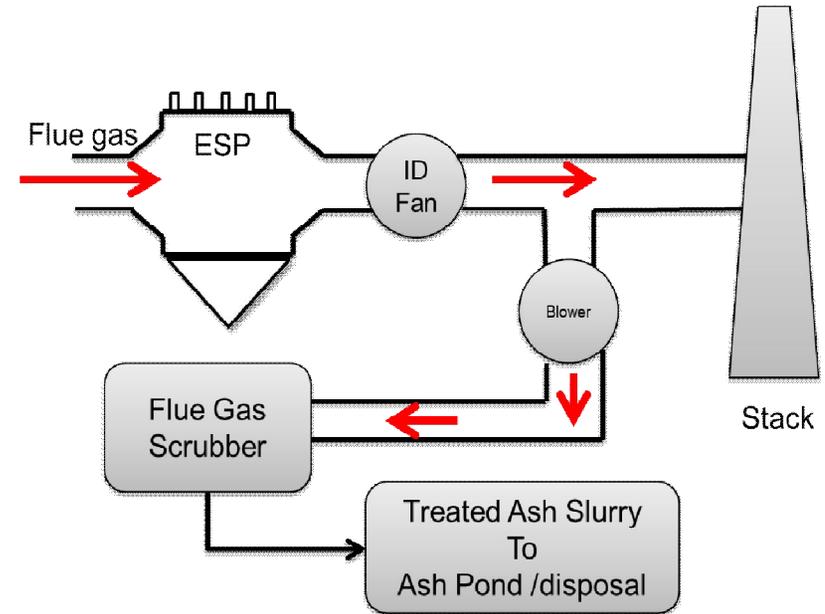
Flue Gas in ETP



Further Studies



Ash Slurry Sump



Schematic studies

Further Studies

Parameter				
	Slurry	Slurry	blower	blower
	1 ton/Hr	100 ton/Hr	60 M3/Hr	6000 M3/Hr
KW	0.746	10.444	0.1865	0.746
Rs./unit	2	2	2	2
Rs./per year	13069.92	182978.88	3267.48	13069.92
Flow	0.3 lps	27.78 lps	8.3 lps	830 lps
design	0.5 lps at 15M	30.5 lps at 20M	189 lps at 32"	1227 lps at 32"
pp. Cost, Rs	10000	37000	18900	25200
Base plate coupling, Rs	3800	15000		
Motor, Rs	5850	29000	3700	6700
Total Cost (Rs.), Rs	19650	81000	22600	31900
CO2 penalty	0.60 Kg	8.36 Kg	0.15 Kg	0.60 Kg

Energy Consumption for further studies

Further Studies

Aqueous Mineralization in Brine Water (seawater):



Basic Chemistry

Further Studies

Aqueous Mineralization in Brine Water (seawater):

Constituent	as	Sea water	CW at 1.5 COC	Sweet water
Calcium	Ppm as CaCO ₃	1100	1650	100
Magnesium	Ppm as CaCO ₃	5200	7800	50
Sodium and Potassium	Ppm as CaCO ₃	16680	25020	115
Total Cations	Ppm as CaCO ₃	22980	34470	265
Bicarbonates	Ppm as CaCO ₃	nil	Nil	200
Carbonates	Ppm as CaCO ₃	180	270	15
Sulphates	Ppm as CaCO ₃	2800	4200	15
Chlorides	Ppm as CaCO ₃	20000	30000	35
Nitrates	Ppm as CaCO ₃	nil	Nil	Nil
Total Anions	Ppm as CaCO ₃	22980	34470	265
Silica	Ppm SiO ₂	5.0	7.5	30
pH value		7.6-8.0		8.7
Turbidity	NTU	20.0	30	500
COD	Ppm as O ₂	155		
BOD	Ppm as O ₂	9.0		
TDS		41000	61500	
Total Iron	As ppm Fe			2.0

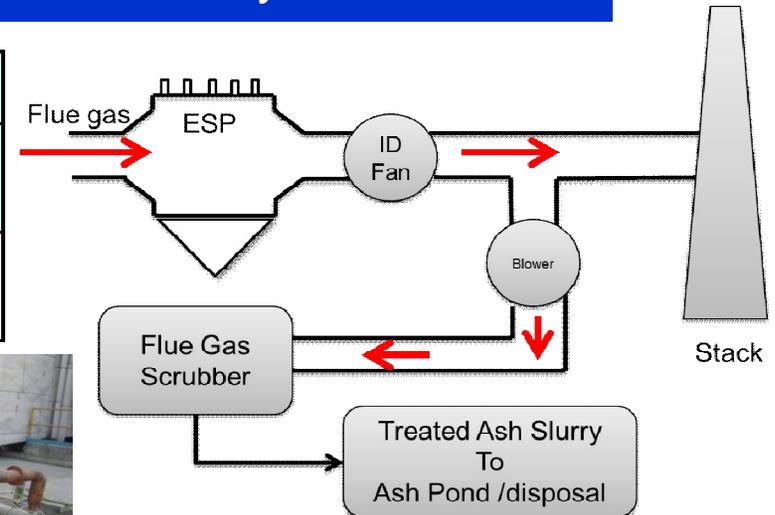
Further Studies

Aqueous Mineralization in Brine Water (seawater):

Parameters	Before passing flue gas			After passing flue gas		
	Fly ash slurry with sea water	Make up water	Circulating water	Fly ash slurry with sea water	Make up water	Circulating water
pH	7.52	8.55	8.34	4.02	6.6	6.5
Conductivity	55400	31400	40000	39100	31400	38200
total Hardness ppm as CaCO ₃	7200	4800	5600	5400	4000	4800
Ca H ppm as CaCO ₃	1200	800	800	1000	800	800
Mg H ppm as CaCO ₃	6000	4000	4800	4400	3200	4000
P-Alkilinity ppm as CaCO ₃	0	12	14	0	0	0
M-Alkilinity ppm as CaCO ₃	60	108	134	0	78	94
Chloride ppm as CaCO ₃	31584	16920	20868	21432	16920	20868
Sulphate ppm	5088	202.2	216.4	2229	1684	1750.7
Iron ppb	0.11	0	1.02	2.5	2.5	1
SiO ₂ ppm	1.31	1.97	2.55	3.8	0.62	0.34
TSS ppm	630	16	10	688	22	84
TDS ppm	42276	26917	24094.7	32712	24716	31500

Lab Scale Testing and Design of Pilot Plant for CO₂ utilization through Mineralization of fly ash

S.No	Slurry Vol.	F.G. Vol.	Amount of gas absorbed	
			CO ₂ absorbed	SO ₂ absorbed
1	1 ton/hr	30 m ³ /hr	0.1 kg/hr	1450 mg/NM ³ (Fully absorbed)



Objectives:

1. CO₂ Utilization
2. Reduction in scaling in ash pipelines
3. Reduction in acid consumption
4. Removal of SO_x
5. Carbonated ash for construction purposes or Agriculture use

Status:

- Lab. studies conducted at Dadri **with Ramagundam FA.**
- Established carbonation by mixing CO₂ in ash Slurry with Ramagundam fly ash.
- Tests started at Ramagundam # 4 B ID Fan
- Analysis work is in progress



Tests with Dadri Flue gas

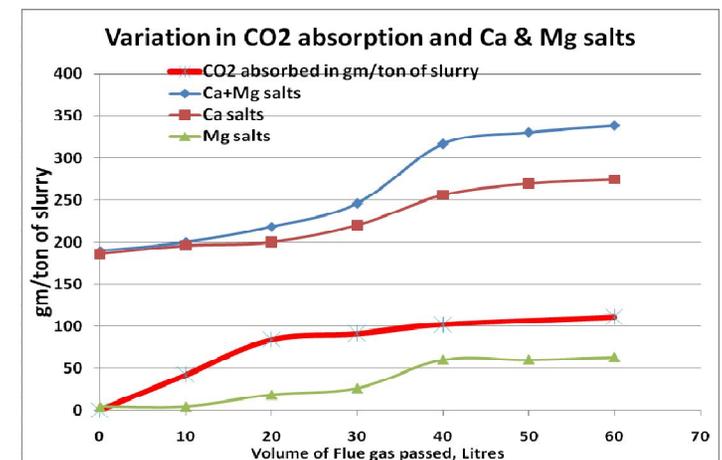


Tests at Ramagundam



Carbonated fly ash after 2 days in air

Schematic of trials



Conserve Resources



Thank You