Flue Gas Desulfurization (FGD) Basics for Illinois
Coal-Fired Electrical Generating Units (EGUs) in Illinois

- There are currently 34 coal-fired units operating in Illinois at 15 power plants.
- 20 of those 34 units currently employ one of several technologies for post-combustion flue gas desulfurization (FGD).
- Most operating coal-fired EGUs in Illinois are burning low-sulfur coal from the Western U.S. to lower emissions of Sulfur Dioxide ($\text{SO}_2$), while a few continue to burn Illinois coal.
- The sulfur content of Illinois coal is the primary barrier to its use in power generation in Illinois and elsewhere.
## Coal-Fired Power Plants in Illinois

<table>
<thead>
<tr>
<th>Plant</th>
<th>Size</th>
<th>Control</th>
<th>Coal</th>
<th>Owner</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baldwin – 3 Units</td>
<td>2032 MW</td>
<td>Dry Lime FGD</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Havana – 1 Unit</td>
<td>493 MW</td>
<td>Dry Lime FGD</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Hennepin – 2 Units</td>
<td>326 MW</td>
<td>Low Sulfur Coal</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Coffeen – 2 Units</td>
<td>984 MW</td>
<td>Wet Limestone FGD</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Duck Creek – 1 Unit</td>
<td>484 MW</td>
<td>Wet Limestone FGD</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>ED Edwards – 2 Units</td>
<td>728 MW</td>
<td>Low Sulfur Coal</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Joppa Steam – 6 Units</td>
<td>1364 MW</td>
<td>Low Sulfur Coal</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Kincaid – 2 Units</td>
<td>1297 MW</td>
<td>Dry Sorbent Injection</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Newton – 1 Unit</td>
<td>748 MW</td>
<td>Low Sulfur Coal</td>
<td>PRB</td>
<td>Vistra</td>
</tr>
<tr>
<td>Powerton – 4 Units</td>
<td>1673 MW</td>
<td>Dry Sorbent Injection</td>
<td>PRB</td>
<td>Midwest Generation</td>
</tr>
<tr>
<td>Waukegan – 2 Units</td>
<td>756 MW</td>
<td>Low Sulfur Coal</td>
<td>PRB</td>
<td>Midwest Generation</td>
</tr>
<tr>
<td>Will County – 1 Unit</td>
<td>534 MW</td>
<td>Low Sulfur Coal</td>
<td>PRB</td>
<td>Midwest Generation</td>
</tr>
<tr>
<td>CWLP – 4 Units</td>
<td>567 MW</td>
<td>Wet Limestone FGD</td>
<td>Illinois</td>
<td>Municipal</td>
</tr>
<tr>
<td>Prairie State – 2 Units</td>
<td>1664 MW</td>
<td>Wet Lime FGD</td>
<td>Illinois</td>
<td>Independent</td>
</tr>
<tr>
<td>SIPC Marion - 2 Units</td>
<td>312 MW</td>
<td>Fluidized Bed Limestone/Wet Lime FGD</td>
<td>Illinois</td>
<td>Independent</td>
</tr>
</tbody>
</table>
Air Quality Issues Related to SO$_2$ Emissions

- The primary consideration related to SO$_2$ emissions from coal-fired EGUs is meeting the National Ambient Air Quality Standard (NAAQS) for SO$_2$ concentrations in ambient air in any area accessible to the public.
- Areas of concern for the SO$_2$ NAAQS are generally localized near large emitters of SO$_2$.
- SO$_2$ also reacts in the atmosphere with other pollutants to form constituents of fine particulate matter (PM2.5).
- There is a NAAQS for PM2.5, and PM2.5 also travels to other areas (transport).
- Transport of PM2.5 also contributes to visibility impairment in National Parks and other areas designated Class I Areas by the USEPA under the federal Regional Haze Rule.
Federal Regulations Limiting SO₂ Emissions

- SO₂ emissions from power plants have been limited by federal cap-and-trade programs such as the Acid Rain Program, the Clean Air Interstate Rule (CAIR), and currently the Cross-State Air Pollution Rule (CSAPR).

- In these cap-and-trade programs, a total SO₂ emissions budget in tons is set for a region, and that number of emission allowances is created. At the end of a year a source must hold a number of allowances equal to its emissions. Allowances for SO₂ emissions can be traded between sources to meet emissions at each source.

- Sources may choose to control emissions using FGD where it is economically viable, or a source can purchase allowances to cover its emissions. Sources with SO₂ controls can offset the cost of controls by selling excess allowances. This encourages the installation of pollution control equipment where it is most economically viable.

- Acid Rain Program – 1995 – Regional Budget – 8.95 million tons
- CAIR – 2009 – Phase I Regional Budget – 3.6 million tons
  Phase II Regional Budget – 2.5 million tons
- CSAPR – 2015 – Regional Budget from 2017 and after - 1.4 million tons
Allowance Prices in Federal Programs

The price for a one-ton allowance for SO₂ has dropped from an average price above $500 in 2007 to a range between $2-4 today due to a number of factors, including a significant emissions decrease nationwide because of the above programs. This decrease in emissions has come about from the installation of controls, use of low sulfur coal, and the retirement of older coal-fired units.
State Regulations Limiting SO$_2$ Emissions

- State regulations aimed at attaining the SO$_2$ NAAQS around power plants are found in Title 35 of the Illinois Administrative Code (IAC) Part 214.603. These limits are source-specific and in terms of lb of SO$_2$ per hour. These rules are bringing all areas of Illinois into attainment of the SO$_2$ NAAQS.

- Additional EGU limits for SO$_2$ are found in 35 IAC Part 225 in the Combined Pollutant Standard (CPS) and the Multi-Pollutant Standard (MPS).

- The MPS and CPS contain SO$_2$ limits in terms of lbs. of SO$_2$ per million Btu (lb/mmBtu), and are evaluated on the basis of average emissions from an entire fleet of EGUs.

- Emission limits in the MPS and CPS range from 0.11 lb/mmBtu to 0.23 lb/mmBtu.
Sulfur Content of Various Coal Types

• Illinois Coal:
  o Bituminous coal
  o Typical heating value around 11,800 mmBtu/pound
  o Recent spot prices around $32/ton – August 2018
  o $O_2$ emissions in the range of 3 - 5 lb/mmBtu upon combustion

• Powder River Basin (PRB) Coal:
  o Originates in the Powder River Basin in Wyoming and Montana
  o Sub-bituminous coal
  o Typical heating value around 8,800 mmBtu/lb
  o Recent spot prices around $12/ton – August 2018
  o Transportation costs by rail to Illinois around $21/ton
  o $SO_2$ emissions in the range of 0.5 – 0.8 lb/mmBtu and can be lower by contract with supplier

Data from Energy Information Administration (EIA) – https://www.eia.gov/coal/data.php
Compliance Measures for Meeting SO$_2$ Limits

• Uncontrolled SO$_2$ emissions from coal combustion range from 0.5 to 5.0 lb/mmBtu for PRB and Illinois Coals.

• Limits applied to units (and fleets of units) range between 0.11 and 1.2 lb/mmBtu.

• Some reduction in SO$_2$ emissions can come from coal washing, which physically removes sulfur compounds prior to combustion. This can be done on-site or off-site. It is unclear how much of an impact this has on current emissions in Illinois.

• For MPS and CPS facilities, averaging emissions between sources with pollution controls and sources without controls provides flexibility.

• The bulk of emission reductions comes from use of low sulfur coal and post-combustion flue gas desulfurization or FGD.
What is considered FGD?

- FGD generally removes $\text{SO}_2$ from combustion gases by using an alkaline reagent to absorb the pollutant to produce a solid compound that can be removed.

Three different types of FGD are typically used for EGUs today:

- Wet Scrubbers – Use a slurry of limestone or lime to react with flue gas.
- Dry Scrubbers – Use similar sorbent slurries, but the flue gas heat evaporates all the water in the added slurry, and the salts formed by acid gases and alkaline sorbent are collected by the particulate control device.
- Dry Sorbent Injection – A dry sorbent is injected directly into the combustion chamber, the flue gas duct ahead of the particulate control, or an additional reaction chamber.
Wet Scrubber Systems

• Wet scrubber systems achieve the highest SO$_2$ control efficiencies, typically in a range of 90 – 95%, but can be higher.

• Wet scrubber systems are typically the most expensive types of FGD because of the high capital cost.

• Additional annual operation and maintenance costs include the cost of limestone or lime and the energy required to operate the controls.

• Wet scrubber systems are often the most appropriate control technology for large EGUs.
Wet Scrubbers (cont.)

Costs are given in $/kW, and $ per ton of SO$_2$ removed.

• A wet scrubber for a unit larger than 400MW has control costs in the range of $200 - $500 per ton of SO$_2$ removed.

• Capital costs for such a unit are in the neighborhood of $100 – 250 per kW, so for a 500MW unit, capital costs would be between $50 – 125 million.

• Total annualized cost for wet scrubber systems for a large EGU could be in the range of $10 – 25 million annually, including amortized capital costs and operation and maintenance costs.
Dry Scrubbers

- Dry scrubbers, or spray dryers, can typically achieve control efficiencies between 80 – 90%.
- Dry scrubbers are typically less expensive than wet systems because handling of wet waste products is not required.
- Dry scrubbers are typically used for units of 200 MW or less, but multiple spray dryers can be employed for larger units.
- A dry scrubber, for a unit of 200 MW has control costs in the range of $150 - 300 per ton of $SO_2$ removed.
- Capital costs for such a unit are in the neighborhood of $40 – 150 per kW, so for a 500MW unit, capital costs would be between $20 – 75 million.
- Total annualized cost for dry scrubber systems for an EGU of that size could be in the range of $10 – 25 million annually, including amortized capital costs and operation and maintenance costs.
Dry Scrubber Diagram

Spray Dryer Absorber (SDA)

Lime
Water
Lime Slaker
Lime Slurry Tank

Flue Gas
Spray Dryer Absorber

Atomizer
Particulate Collector

Clean Gas To Atmosphere
Stack

Dry FGD / fly ash by product
Dry by product to use or disposal
Dry Sorbent Injection

- Dry sorbent injection (DSI) systems can typically achieve control efficiencies between 50 – 80%, but can be higher.
- Costs for DSI are heavily dependent upon the cost and usage rate of the sorbent because capital costs are relatively low for installation (as low as $3 million).
- DSI is effective for units of any size, but more sorbent is required for more SO$_2$ removal.
- DSI costs for a given unit or application can vary greatly due to the size of a unit and the target control efficiency at a given unit, but are generally lower than the annualized costs of wet or dry scrubber systems due to the low capital costs of installation.
Dry Sorbent Injection (DSI) Diagram
Economics of FGD and Low Sulfur Coal

- Uncontrolled EGUs in Illinois burning PRB coal are currently emitting \( \text{SO}_2 \) at a rate of around 0.5 lb/mmBTU. Uncontrolled emissions from Illinois coal would be in the range of 3.6 lb/mmBtu.
- Capital costs for new wet and dry scrubbers on existing units have generally been too high in recent years to install.
- Use of Illinois coal would require wet or dry scrubbers to match rates achieved by simply burning lower sulfur coal.
Economics of FGD and Low Sulfur Coal (cont.)

- Recent installations of FGD in Illinois have been lower-cost dry sorbent injection systems applied to units burning PRB coal to meet Illinois’ $SO_2$ rules, as well as to control other acid gases.
- Federal trading programs are no longer an incentive to install FGD due to low allowance prices.
- Illinois coal prices and delivered PRB coal prices are comparable on a dollar per Btu basis. While Illinois coal delivers higher heat rates per dollar, costs for additional $SO_2$ controls outweigh that heat-rate advantage.
Caveats

• Cost estimates and control efficiency estimates vary greatly depending upon the source of information, the age of the information, and a variety of conditions at the units to be controlled.

• Control cost data for scrubbers is from USEPA and is in 2001 dollars. More updated information was not available.

• Coal price and delivery price data is 2018 Energy Information Administration (EIA) data.

• $SO_2$ allowance prices in federal trading programs for $SO_2$ have continued to decline in recent years.