Analysis of the Illinois Coal Industry and Electrical Generation in Illinois

Flue Gas Desulfurization Task Force Report
December 2018

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Executive Summary

The Flue Gas Desulfurization ("FGD") Task Force Act (20 ILCS 5120) created the FGD Task Force "to increase the amount of Illinois Basin coal use in generation units," and to "identify and evaluate the costs, benefits, and barriers of new and modified FGD, or other post-combustion sulfur dioxide emission control technologies, and other capital improvements, that would be necessary for generation units to comply with the sulfur dioxide National Ambient Air Quality Standards (NAAQS) while improving the ability of those generation units to meet the effluent limitation guidelines (ELGs) for wastewater discharges and enhancing the marketability of the generation units' FGD byproducts." The purpose of this document is to provide background and analysis necessary for policy makers to arrive at informed decisions regarding Illinois coal use in Illinois electrical generation.

The FGD Task Force convened on five occasions. These meetings were publicly noticed and were conducted in accordance with the Public Meetings Act. Meetings were held on September 26th, October 10th, October 24th, November 11th, and December 17, in 2018. Members of the Task Force included Illinois House Representatives Avery Bourne, Linda Chapa LaVia, Anna Moeller, and Dave Severin; Illinois Senators Dale Fowler, Andy Manar, and Paul Schimpf; Alec Messina, Director of the Illinois Environmental Protection Agency; Tom Benner, Director of the Department of Natural Resource's Office of Mines and Minerals; William Matuscak, Archer Daniels Midland Company ; Doug Brown, City, Water, Light & Power; and Phil Gonet, Illinois Coal Association.

At these public meetings, relevant information was brought forth by Task Force Members and their representatives, as well as from interested parties. This report has been drafted by staff of the Illinois Environmental Protection Agency, contains all relevant information brought forth and presented to the Task Force by Task Force Members and interested parties, as well as minutes of the meeting in the Appendix to this document.

This report contains a history of the decline in the use of Illinois coal in electricity generation and the factors leading to this decline. These factors include regulations limiting sulfur dioxide ("SO_2") emissions from power plants, the economics of controlling the emissions of SO_2 in coal-fired electrical generating units ("EGUs"), and the use in Illinois power generation of low-sulfur coal from the Western United States.

This report also discusses a relatively new technology for SO_2 emission control whose proponents claim is extremely well-suited for application to coal-fired powered EGUs combusting Illinois coal, and the barriers to new technologies for emission control.

Background

The Clean Air Act Amendments of 1990 and the environmental regulations since then have contributed to a significant detrimental effect on the Illinois coal industry. A major component of these regulations is the reduction of sulfur dioxide ("SO_2") emissions from coal burning power plants, as SO_2 is a pollutant that can be harmful to the human respiratory system and is conducive to rain acidification. The sulfur content of coal mined in Illinois is high relative to other sources of coal, which leads to higher emissions of SO_2 when combusted in the absence of add-on SO_2 emission control.

Power plants have had several options to comply with SO_2 limits in these regulations. The plants could install pollution control equipment such as flue gas desulfurization ("FGD") systems, purchase allowances to permit SO_2 emissions, switch to lower-sulfur sources of coal (primarily sub-bituminous coal from the Powder River Basin in Wyoming), or cease operation. While some Illinois power generators did install pollution control equipment to allow them to continue to burn Illinois coal, the majority of the coal-fired generators in the state chose to switch their fuel source to low-sulfur coal. Additionally, some power plants choose to burn low-sulfur western coal at generation units that have SO_2 controls, but this is attributable to stringent Illinois SO_2 requirements discussed in more detail in later sections of this report.

The Illinois utilities choosing to switch fuel sources were led by Commonwealth Edison Company ("Com Ed") which operated several coal power plants at the time, in addition to operating nuclear power plants in Illinois. Com Ed was having difficulty in receiving approval from the Illinois Commerce Commission ("ICC") in incorporating those nuclear plants fully into its rate base. Faced with the cost of hundreds of millions of dollars for scrubbers requiring approval by the ICC in a lengthy, contentious rate case, Com Ed opted for alternatives to meet the SO_2 limits. Com Ed determined it could meet the SO_2 limits by switching to low-sulfur Western coal. A key factor in this decision was an order from the ICC which approved transportation costs as part of the fuel costs meaning these costs were immediately recoverable in electric sales through the Fuel Adjustment Clause. This decision was based on the Interstate Commerce Clause prohibiting laws and rules that would support Illinois coal to the detriment of competition from products produced outside Illinois.

The impact on the Illinois coal industry was immediate and negative. Coal production declined 50% in 13 years, from 62 million tons in 1990 to 31 million tons in 2003. Since the mid-1990s, roughly 30 - 50 million tons per year of coal from Western states have been transported to be burned in Illinois power plants. Over the same period, 85% of the coal produced in Illinois has been exported for use out of state.

Since 1990, efforts to encourage Illinois power plants to switch to Illinois coal have faced two major hurdles, neither of which has been overcome. First, in 1991 the General Assembly enacted legislation that ordered the ICC to approve the construction of four scrubbers at unspecified power plants. The law was challenged by interests from the Western states as interfering with the free flow of interstate commerce in violation of the

Commerce Clause of the U.S. Constitution. In 1995, the U.S. Court of Appeals in the Seventh District struck down the 1991 Illinois law. This precedent presents difficulties for the state in providing incentives or subsidies encouraging the use of Illinois coal in Illinois power plants.

Second, a law enacted in 1997 provided for the deregulation of electric generation in Illinois. Utilities no longer could request rate increases from the ICC to pay for the construction of new power plants or large capital expenditures for existing power plants such as pollution control equipment. In fact, utilities own very little generation in Illinois, with most generation owned by merchant generation companies that must recover their costs in a competitive market that includes other states. In many cases, investments in pollution control equipment such as FGD cannot be recouped or repaid while remaining competitive in Illinois' deregulated electric market. Together these factors have led to the continued decline in Illinois coal production.

Illinois Coal Industry

Illinois sits atop much of the Illinois Coal Basin, and coal underlies 65% of the state. Illinois has the largest reported bituminous coal resources of any state in the U.S., totaling 38 billion tons of recoverable coal reserves. This represents one quarter of the nation's bituminous coal reserves. The heating value of the coal reserves in Illinois is greater than for all the oil reserves of Saudi Arabia and Kuwait.

Currently, 85% of coal production in Illinois comes from two coal seams, the Herrin No. 6 and the Springfield No. 5, and there are 18 active coal mines in 13 counties in Illinois. These seams average from 4.5 to 8 feet in thickness, and the heating value is between 10,200 and 14,000 Btu per pound.

Between1990 and 2007, Illinois coal production declined from over 61,000,000 tons to 32,000,000 tons mined per year. In that same period, consumption of Illinois coal in Illinois facilities declined from 15,598,500 tons per year to 5,690,400 tons per year, or from 59% to 9%. Yet, in that same period, total coal consumption in Illinois from all sources (Illinois coal and non-Illinois coal) increased from approximately 25,000,000 tons to over 60,000,000 tons.

Of the 15 power plants in Illinois that are significant consumers of coal, 12 are located within 50 miles of an Illinois coal mine. However, use of coal mined in Illinois at these facilities has declined dramatically, presumably due to the environmental and economic factors discussed in this report.

A more detailed description of Illinois' coal production and utilization in Illinois can be found in the presentation to the FGD Task Force given by the Department of Natural Resources.

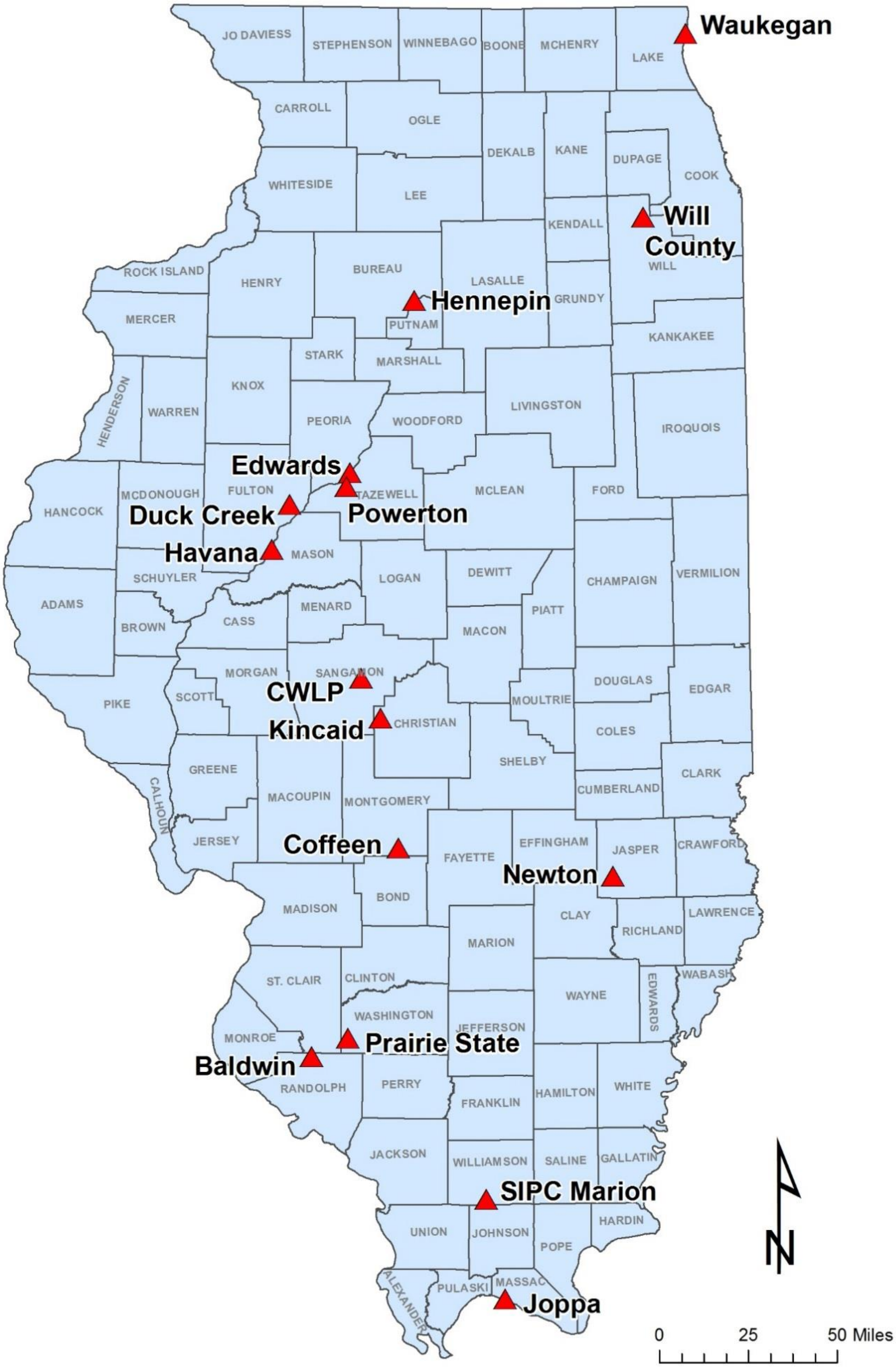
Coal-Fired Electrical Generating Units in Illinois

There are currently 34 coal-fired electrical generating units ("EGUs") operating in Illinois at 15 power plants. Twenty of those 34 units currently employ one of several technologies for post-combustion FGD. Figure 1 shows the location of the operating coal-fired EGUs in Illinois, and Table 1 lists those power plants and the methods used for reducing SO_2 emissions at those plants.

Table 1. List of Coal-Fired Electrical Generation in Illinois

Plant	Total Capacity	Low-Sulfur Coal/Control Equipment	Coal Source	Operator
Baldwin – 2 Units	1200 MW	Dry Lime Scrubber	PRB	Vistra
Havana – 1 Unit	434 MW	Dry Lime Scrubber	PRB	Vistra
Hennepin – 2 Units	294 MW	Low-Sulfur Coal	PRB	Vistra
Coffeen – 2 Units	915 MW	Wet Limestone Scrubber	PRB	Vistra
Duck Creek – 1 Unit	425 MW	Wet Limestone Scrubber	PRB	Vistra
ED Edwards – 2 Units (Bartonville)	585 MW	Low-Sulfur Coal	PRB	Vistra
Joppa Steam – 6 Units	802 MW	Low-Sulfur Coal	PRB	Vistra
Kincaid – 2 Units	1108 MW	Dry Sorbent Injection	PRB	Vistra
Newton – 1 Unit	615 MW	Low-Sulfur Coal	PRB	Vistra
Powerton – 4 Units (Pekin)	1673 MW	Dry Sorbent Injection	PRB	Midwest Generation
Waukegan – 2 Units	756 MW	Low-Sulfur Coal	PRB	Midwest Generation
Will County – 1 Unit (Romeoville)	534 MW	Low-Sulfur Coal	PRB	Midwest Generation
CWLP – 4 Units (Springfield)	567 MW	Wet Limestone Scrubber	Illinois	Municipal
Prairie State – 2 Units (Marissa)	1664 MW	Wet Lime Scrubber	Illinois	Consortium of Rural Electric Cooperatives
SIPC Marion - 2 Units	312 MW	Fluidized Bed Limestone/Wet Lime Scrubber	Illinois	Rural Electric Cooperative

Figure 1. Coal-Fired Electrical Generation in Illinois



As can be seen in Table 1, the majority of Illinois' coal-fired generation capacity is combusting coal from the Powder River Basin ("PRB") located in the Western states of Wyoming and Montana. The following sections of this report provide a more detailed analysis of the environmental and economic factors that have led to these fuel choices. As prefaced in the Background section of this report, the high sulfur content of Illinois coal seemingly remains the primary barrier to its use in power generation in Illinois and elsewhere.

Air Quality Issues and Regulations Related to Sulfur Dioxide Emissions

While the aforementioned Clean Air Act Amendments addressed SO_2 emissions and their impact on acid rain, more recent regulations for SO_2 emissions have been aimed at impacts on human health and other environmental quality impacts. Acid rain is no longer a significant consideration in limiting emissions of SO_2.

Currently, the primary consideration related to SO_2 emissions from coal-fired EGUs is meeting the National Ambient Air Quality Standards ("NAAQS") that limit allowable concentrations of pollutants in ambient air in any area that is accessible to the public.

The NAAQS for SO_2, revised in 2010, is 75 parts per billion, assessed on a 1-hour basis. Areas of concern for the SO_2 NAAQS are generally localized near large emitters of SO_2, such as large coal-fired facilities. In 2015, Illinois adopted new rules for reducing SO_2 emissions in two areas of the State that were determined to be in nonattainment of the SO_2 NAAQS. Both of those areas were impacted by SO_2 emissions from coal-fired power plants, and the adopted rules contained new emission limits for those plants. Currently, those nonattainment areas have SO_2 concentrations that meet the NAAQS, and will be redesignated to attainment of the standard in the near future.

SO_2 also reacts in the atmosphere with other pollutants, such as ammonia, to form fine particles that are regulated as a different pollutant known as PM2.5, or particulate matter with particles being 2.5 micrometers or less in diameter. PM2.5 is known to have human health effects, including respiratory and cardiovascular impacts, and there is also a NAAQS for PM2.5. The PM2.5 NAAQS, established in 2012, is 12.0 micrograms per cubic meter ($\mu g/m^3$) on an annual basis, and 35 $\mu g/m^3$ on a 24-hour basis. All areas of Illinois are currently monitoring PM2.5 concentrations that are in attainment of these standards.

Once PM2.5 is emitted or formed in the atmosphere, it can also travel to other areas and other states. This is generally called pollutant transport. Transport of PM2.5 can contribute to nonattainment of the NAAQS in other areas or other states, and also may contribute to visibility impairment or hazy atmospheric conditions. Control of SO_2 emissions to limit formation of PM2.5 is a key goal of the Regional Haze Rule. The Regional Haze Rule is aimed at reducing visibility impacts in National Parks and other areas designated by the USEPA as "Class I Areas" under the rule. The Regional Haze Rule was designed to return all Class I Areas in the United States to natural visibility conditions by the 2065. Illinois is currently meeting all of its obligations related to the Regional Haze Rule.

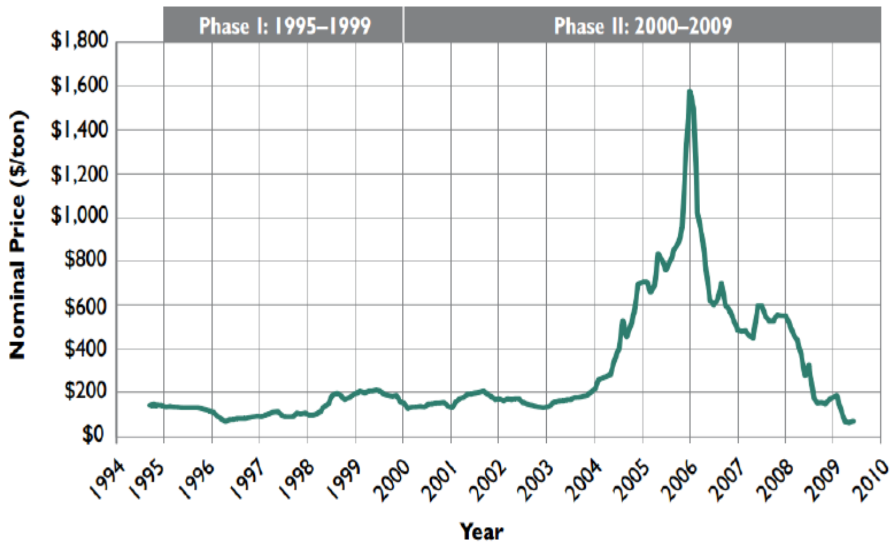
Federal Regulations Limiting SO_2 Emissions

Emissions of SO_2 in Illinois and the United States, in general, have been drastically reduced since the 1990s. Much of this reduction is a result of a series of federal "cap and trade" programs that continue today. In a cap and trade program, a total SO_2 emissions budget, in tons, is set for an entire region of the United States, and that number of one-ton emission allowances is created. At the end of a year, an emission source, such as a power plant, must hold a number of allowances equal to its emissions in that year. These allowances are allocated to sources based on a number of factors, including historical emissions. The allowances can be traded between sources to meet their emissions in that year. This cap and trade system encourages control of emissions in the most economically efficient manner. A source may choose to control emissions using control equipment, such as FGD where it is economical to deploy, or a source can simply purchase allowances to cover its emissions. A source with SO_2 controls may be able to offset a portion of the cost of those controls by selling excess allowances that are not needed due to the controls at that source. This incentivizes the installation of control equipment where it is most economically viable. In a cap and trade program, the availability and price of allowances may fluctuate, but the total emissions in the affected region can be guaranteed to be less than the emission budget. These cap and trade programs have been very successful in ratcheting down SO_2 emissions in the Eastern United States since 1995.

The Acid Rain Program, beginning in 1995, was designed with a budget of 8.95 million tons of SO_2. At the time, this budget amounted to a reduction of approximately 7 million tons of SO_2 annually. The next iteration of SO_2 cap and trade program was the Clean Air Interstate Rule ("CAIR"). CAIR began with an emission budget of 3.6 million tons in 2009, which was reduced in Phase II to 2.5 million tons. The current SO_2 cap and trade program in place is the Cross-State Air Pollution Rule ("CSAPR"), which began with an emission budget in line with CAIR, but starting in 2017, the SO_2 emission budget is set at 1.4 million tons. Thus, in the years between 1995 and 2017, SO_2 emissions from affected facilities in the Eastern United States have been reduced from approximately 17 million tons annually to less than 1.4 million tons annually.

The reduction in SO_2 emissions from these programs was achieved in the power sector by a combination of pollution control installations, the use of low-sulfur PRB coal, and the retirement of less economically viable and older coal-fired facilities. In recent years, as reductions have occurred, the cost for emission allowances has plummeted as excess allowance are available. This has led to less incentive to install FGD, and a greater incentive to use low-sulfur coal and to purchase allowances if necessary.

Figure 2. Allowance Prices in Federal Trading Programs



As can be seen in Figure 2, allowance prices remained steady in the range of $150 to $200 per ton until 2004. Allowance prices then increased sharply due to the uncertainty of the impact of lower budgets when CAIR was proposed. This meant that power plants could elect to install emission controls to reduce their emissions and thereby also reduce the number of allowances required to be surrendered for compliance. Any subsequent surplus in allowances from those allocated compared to allowances required to be surrendered could be sold to assist in offsetting a portion of the costs associated with installing and operating the new emission control device. However, since that time allowance prices have continued to decline precipitously to $2 a ton or lower today.[1] At such a low price, the federal trading program is no longer an incentive for the installation of FGD.

State Regulations Limiting SO_2 Emissions

Illinois regulations aimed at attaining the NAAQS for SO_2 near power plants and other large sources of SO_2 emissions can be found in Title 35 of the Illinois Administrative Code ("35 IAC") in Part 214.603. These limits are source-specific and are in terms of pounds of SO_2 emitted per hour to ensure that SO_2 concentrations around those sources remain below the NAAQS. These rules assist in bringing all areas of Illinois into attainment of the NAAQS for SO_2.

Additional limits for SO_2 from power plants are found in 35 IAC Part 225 in the Multi-Pollutant Standard ("MPS") and Combined Pollutant Standard ("CPS"). The MPS and CPS contain rate-based SO_2 limits in terms of pounds of SO_2 per million Btu ("lb/mmBtu") of heat input to a unit. These limits are evaluated on the basis of average emissions from an entire fleet of EGUs controlled by a single owner or operator. Current emission limits in the MPS and CPS range from 0.11 lb/mmBtu to 0.23 lb/mmBtu. These emission rates are much

[1] 2011 average SO_2 allowance prices at auction were $2.81 and have not exceeded $1 since.

lower than can be achieved from the uncontrolled combustion of Illinois or PRB coal, but the emission averaging means that not all units in a given fleet need additional SO_2 control equipment for that fleet of units to comply with the average limits.

These state regulations are currently a more significant driver for SO_2 emission control in Illinois than the federal trading programs. These limits apply to all of the units listed in Table 1 that are currently operated by Vistra and Midwest Generation, and also account for all of the facilities on that list burning PRB coal.

Compliance Measures for Meeting SO_2 Limits

As previously noted, SO_2 emission limits applicable to units, and to fleets of units, range between 0.11 lb/mmBtu and 1.2 lb/mmBtu. Uncontrolled emissions from coal combustion range from 0.5 to 5.0 lb/mmBtu depending on the source of the coal and other factors.

The primary method of emission reductions for these power plants is the use of low-sulfur coal from outside of Illinois and post-combustion FGD.

Comparison of Illinois Coal and PRB Coal

Again, a major factor in the decline in Illinois coal use has been the availability and cost of low-sulfur PRB coal. A comparison of Illinois coal to PRB coal and their respective suitability for use in Illinois EGUs must include the heating value of the fuels, fuel costs, transportation costs, and the sulfur content of each coal type. The following comparison uses data from the Energy Information Administration ("EIA") and contains approximate values that can be applied generally to Illinois coal and PRB coal. These values vary depending on more specific locations from which a particular coal has been produced.

Illinois coal is a bituminous coal with a heating value around 11,800 Btu per pound. PRB coal is a subbituminous coal with a heating value around 8,800 Btu per pound. This amounts to an average heating value for Illinois coal that is 34% greater than PRB coal.

Recent spot prices for Illinois coal from EIA have been approximately $32 per ton, while spot prices for PRB coal have been approximately $12 per ton. These relatively low costs for PRB coal can be attributed to its lower production costs due to the coal's relative proximity to the surface and recoverable coal seams that can be as much as 80 – 100 feet thick. However, the delivery cost to transport PRB coal to users in Illinois is around $21 per ton, increasing the delivered price of a ton of PRB coal to around $33 per ton. As such, Illinois coal and delivered PRB coal are roughly equal in terms of cost in dollars per ton, and delivered Illinois coal can be more expensive than PRB coal on a per-ton basis. However, given the higher heating value of Illinois coal noted above, Illinois coal is generally less expensive than PRB coal on a dollar-per-Btu basis, although some comments to the Task Force have suggested that the cost for Powder River Basin coal is comparable or even less than that for Illinois coal on a dollar-per-Btu basis.

The major factor in the use of PRB coal rather than Illinois coal is the sulfur content of each fuel. SO_2 emissions from uncontrolled combustion of Illinois coal are in a range between 3 and 5 lbs/mmBtu, while emissions from combustions of uncontrolled PRB coal are in a range between 0.4 and 0.9 lb/mmBtu. It is this difference in sulfur content that outweighs the heating value advantage of Illinois coal in most economic considerations. Many power plants can comply with SO_2 regulations by using PRB coal without the capital expenditures and operating costs associated with installing FGD pollution control equipment. FGD systems are unquestionably necessary when burning Illinois coal. Common FGD technologies and the costs associated therewith are discussed in the following section.

Technology for Controlling SO_2 Emissions

In Illinois and elsewhere, the most common and effective compliance measures for reducing SO_2 emissions from coal combustion is the use of low-sulfur coal and the use of post-combustion FGD systems.

In general, FGD systems remove SO_2 from combustion gases by using an alkaline reagent to absorb the pollutant and produce a solid compound that can be removed. Three different types of FGD are typically used today to reduce SO_2 emissions from EGUs: wet scrubbers, dry scrubbers, and dry sorbent injection ("DSI").

Wet scrubbers use a wet slurry, usually of limestone or lime, to react with SO_2 in the flue gas. This reaction of the calcium in the slurry and the SO_2 in the flue gas forms gypsum (CaSO) that can be removed, but must be dewatered, creating wastewater from the process. Wet scrubbing is the most expensive type of FGD due to the high capital cost of installation, but is also often the most appropriate type for large coal-fired boilers. Wet scrubbing also achieves the highest SO_2 control efficiencies, typically in a range of 90 to 95%, but potentially up to 99%. Additional annual operation costs include the cost of lime or limestone sorbent, the energy required to operate the control, and costs associated with wastewater treatment. Further, there are considerable annual maintenance costs as well as additional wastewater regulations, the Effluent Limitation Guidelines, that are imposed on wastewaters associated with scrubbing activities.

Dry scrubbers, or spray dryers, use a sorbent slurry similar to those used in wet scrubbers to react with SO_2in the flue gas, however, in a dry scrubber the flue gas heat evaporates all of the added water in the slurry, and the salts formed by the SO_2 and sorbent are collected downstream by a particulate control device such as an electrostatic precipitator ("ESP") or a fabric filter baghouse. Dry scrubbing typically achieves SO_2 control efficiencies in a range of 80 to 90%, but can also achieve higher efficiencies. Dry scrubbing is generally less expensive than wet scrubbing because handling and treatment of wet waste products is not required, but like wet scrubbing, there are operation and maintenance costs.

DSI systems remove SO_2 by injecting a dry sorbent directly into the combustion chamber, into the flue gas duct ahead of the particulate control, or into an additional reaction chamber designed specifically for sorbent injection. DSI systems are often the lowest-cost option for

SO_2 control due to lower installation costs, but typically only achieve control efficiencies in a range between 50 and 80%. DSI is effective for units of any size, but additional sorbent is required for greater SO_2 removal. Costs for DSI are heavily dependent upon the cost and usage rate of the sorbent, and can vary greatly due to the size of a unit, the desired control efficiency, and a number of other factors specific to any given power plant. Again, there are operating and maintenance costs associated with DSI systems.

Economics of FGD

The most relevant measures for the cost of SO_2 control by FGD are the costs in dollars per ton of SO_2 removed, and the annualized costs of installing and operating an FGD system. The dollars per ton of SO_2 removed figures are useful in comparison to prices for emission allowances. Annualized costs of controls include capital costs amortized over the life of the system and the operation and maintenance costs associated with the control, and provide an understandable estimate of the actual costs to a power plant operators. Estimates for costs have been taken from USEPA information, and the following estimates are based on a unit with a capacity of 500 megawatts. Coal-fired units in Illinois range between 78 and 800 MW, but a 500 MW unit could be considered a unit of typical size in Illinois for the purposes of these estimates.

Wet scrubbing system capital costs range from $50 to $125 million per unit controlled, and annualized costs range from $10 to $25 million annually. Control costs are in a range of $200 to $500 per ton of SO_2 removed. It should be noted that many power plants operate several generating units and total capital costs and annualized costs can be much higher than the estimate above for control of an entire power plant with multiple units.

Dry scrubbing system capital costs range from $20 to $75 million per unit controlled, and annualized costs are also range from $10 to $25 million annually. Control costs are in a range of $150 to $300 per ton of SO_2 removed. As with the cost estimates given for wet scrubbing systems, it should be noted that many power plants operate several generating units and total capital costs and annualized costs can be much higher than the estimate above for control of an entire power plant with multiple units.

DSI system capital costs range from $3 to $15 million, but as previously stated, control costs and annualized costs are heavily dependent upon factors specific to the power plant and their target control efficiency. Again, there are associated operating and maintenance costs.

Capital costs for wet and dry scrubbers in recent years have proven to economically discourage plant owners from installing those FGD types. Recent installations of FGD in Illinois have been the lower-cost DSI systems applied to units that are also burning low-sulfur coal to meet Illinois SO_2 regulation limits, as well as to control other acid gases. Because allowance prices have fallen to the $2-per-ton range, and cost of control with FGD remains in the $150 to $500-per-ton range, the federal trading program is no longer an incentive to install controls. Additionally, with annualized costs in the range of $10 to $25 million, the use of low-sulfur coal from outside Illinois in lieu of installing and operating controls outweighs the advantage Illinois coal would provide with its higher heating value.

Alternative SO_2 Control Technology

At the October 10th meeting of the FGD Task Force, a presentation was made by representatives of Jiangnan Environmental Technology Inc. ("JET"), a company that reports it has been installing and operating ammonia-based FGD systems outside the U.S. According to JET, these ammonia-based FGD systems have many advantages over conventional limestone/lime wet scrubbers and can increase revenue at a power plant through the sale of the byproducts of the systems. JET representatives suggested that use of higher-sulfur Illinois coal in their systems was actually preferable to low-sulfur coal because it would produce more byproduct which is potentially saleable.

According to JET, advantages of ammonia-based FGD systems include: SO_2 control efficiencies of 99% or greater; no wastewater or solid waste; lesser power consumption by the controls and thus lower operating costs; and profits through the sale of ammonia sulfate as a fertilizer.

The company's business model involves financial support for the cost incurred by EGU owner related to installation of the technology, for the costs associated with the packaging and sale of the fertilizer byproduct, and for operation of the control at the plant. JET posits this arrangement provides for essentially no-cost control of SO_2 emissions in addition to a share of the revenue to the plant from the sale of the byproduct.

JET does not currently operate any ammonia-based FGD systems in the U.S., however, the company apparently has installed the technology in over 150 projects worldwide, and claims that the technology is mature and suitable for use in the U.S. Issues of concern for installation of this technology in the U.S. are the permitting difficulties presented by a third-party control operator, potential additional emissions of ammonia and particulate matter, ensuring that there are indeed no issues requiring water permitting, and the issues involving accumulation of byproduct in the event it is not marketable.

Also at the October 10^{th} meeting of the FGD Task Force, an FGD Task Force member representing City Water Light & Power in Springfield presented information regarding new control technologies from the perspective of a power plant operator. The presentation included concerns for power plant operators associated with risk in meeting capacity requirements, compliance risk (since the EGU owner/operator remains responsible for meeting emission limits even if the FGD owner is contractually running the control device), risk from future regulations that could apply to new technologies, permitting (including that the technology would require an application for and issuance of an air pollution control permit from the Bureau of Air, and that the owner/operator would be responsible for the permit of a control device being run by another company), and the ultimate liability of the plant operator for projects at their plants (such as a situation where the company responsible for the control device were to go out of business, all liability for compliance and future operation of those controls would run to the power plant operator). It was suggested that grants to incentivize installation of new technologies may be needed to mitigate some of these risks, and other aspects would require cooperation with government bodies for permitting and regulatory issues.

Public Comments at Meetings of the FGD Task Force

In public comments to the FGD task Force, David Repp, a representative of JET, suggested that the Task Force Report should provide legislative pathways for Illinois to support alternative technologies that would incentivize use of Illinois coal in power generation in Illinois.

In response to these comments, Julie Armitage, Chief of the Illinois EPA's Bureau of Air, suggested that companies offering alternative technological solutions would be best served by communicating directly with power generators in Illinois. Ms. Armitage added that these EGUs have an existing approach for compliance with all requirements regarding emissions of SO_2, and it is ultimately the responsibility of their owners to determine whether an alternative technology is technically and economically appropriate for their emission sources.

Also in Response to Mr. Repp's comments, Phil Gonet, FGD Task Force member and President of the Illinois Coal Association, concurred with Mr. Repp that the Task Force should encourage power generators in Illinois to explore alternative technologies if they could lower compliance costs and assist Illinois' fleet of EGUs.

JET also provided written public comments to the Task Force that have been included in the Appendix to this document.

Peabody, an entity that operates multiple underground coal mines and surface mining operations in the Illinois Basin and the Powder River Basin, also provided the Task Force with written comments.

Vistra, an entity that owns and operates nine coal-fired power plants provided written comments to the Task force discussing the coal price information in this report, additional barriers to use of Illinois coal, and remarks on the comments provided by Peabody and JET.

Input and information provided by FGD Task Force Members and in public comments by interested parties has been incorporated into this report where appropriate and are included in full in the Appendix to this report.

Conclusions

The FGD Task Force was created to examine and identify ways to increase the use of Illinois coal in Illinois power plants. Several reports and presentations were made to the Task Force in its public meetings.

A presentation was given to the Task Force by Jiangnan Environmental Technology (JET), Inc. during one of its meetings about its ammonia-based FGD system, which has been installed and is in operation at over 300 coal-fired units in China. The success of JET's technology could possibly be assessed by way of a third-party, independent evaluation conducted for a utility in Indiana.

A key component of the JET proposal is that JET is committed to building and operating the FGD system. This could provide significant economic benefits to the power plant:

- If it is currently operating an FGD system, the current costs for that system could possibly be eliminated as they relate to the actual scrubber, depending upon a number of factors.

- Fuel switching to Illinois coal could possibly decrease some operating costs. Research conducted for this report indicates that, when analyzed on a dollar-per-Btu delivered basis, Illinois coal cost is less than for coal from the Powder River Basin. However, in some cases Illinois coal use may cause higher operation and maintenance costs, and some comments to the Task Force have suggested that the cost for Powder River Basin coal is comparable or even less than that for Illinois coal on a dollar-per-Btu basis.

- The JET proposal provides for potential sharing of profits with the power plant from the potential sale of fertilizer manufactured from the FGD system byproduct, assuming that buyers can be found for this type of fertilizer.

- The JET technology has a closed loop water system with no discharge of waste off the power plant property, which is an environmental benefit.

From the information gathered for this report, the FGD Task Force acknowledges the challenges to sustaining and increasing the use of Illinois coal, and is encouraged by technological developments that could prove useful in achieving that goal. In the Illinois deregulated electricity market, the cost of constructing, operating, and maintaining FGD systems on independent generating units has been one of the biggest obstacles to the use of Illinois coal. While it would require further site-specific evaluation by EGU owners and operators, the ammonia-based FGD technology presented by JET could possibly overcome hurdles to Illinois coal usage. Currently the investor-owned power plants in Illinois are owned by Vistra Energy and NRG Energy. Accordingly, the Task Force urges Vistra Energy and NRG Energy to seriously consider this technology for its Illinois power plants.

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Appendix

I. **Agendas and Minutes of the FGD Task Force Meetings**

II. **Presentations to the FGD Task Force**

III. **Written Public Comments to the FGD Task Force**

I. Agendas and Minutes of the FGD Task Force

1. September 26, 2018
2. October 10, 2018
3. October 24, 2018
4. November 19, 2018
5. December 17, 2018

PUBLIC NOTICE

of Meeting
Flue Gas Desulfurization Task Force
Wednesday, September 26, 2018
10 a.m. – Noon
Illinois EPA
1021 North Grand Avenue East
Springfield, IL

AGENDA

1. Welcome and introduction of Task Force members
2. Purpose of Task Force
3. FGD Presentation
4. Future topics for discussion
5. Scheduling of future Task Force meetings
6. Opportunity for public comment and questions
7. Adjourn

MINUTES of the

FLUE GAS DESULFURIZATION TASK FORCE MEETING

Held on SEPTEMBER 26, 2018

- Meeting commenced at 10:03 a.m.

- Task Force members present:
  - Director Messina, IEPA
  - Tom Benner, IDNR
  - Representative Bourne
  - Doug Brown, CWLP
  - Representative Chapa LaVia (phone)
  - Phil Gonet, Illinois Coal Association
  - William Matuscak (ADM)
  - Senator Schimpf
  - Representative Severin (phone)

- Welcome

- Recitation of the Purpose of the Task Force

- Brief discussion of proposed elements of FGD report

- Flue Gas Desulfurization presentation by Rory Davis, IEPA

- History of Coal presentation by Phil Gonet, Illinois Coal Association

- Suggestions for future testimony:
  - Gonet: Proposed presentation by JET, Inc. regarding ammonia-based FGD system that would be constructed and operated by Jet, who would sell the by-product as a high-grade fertilizer; currently operating 300 units in China
  - Brown: Proposed presentation of overall costs to operate EGUs
  - Benner: Proposed presentation regarding coal reserves in Illinois
  - Bourne: Proposal to utilize first half of proposed October 24 Task Force meeting for additional testimony

- Future Task Force meetings scheduling:
  - Agreed to next meet on October 10
  - Agreed to proposed schedule of additional meetings including October 24, December 5, and December 19 at 10:00 a.m. at the Springfield IEPA office
  - Proposed to meet the afternoon of November 13 or the morning of November 14

- No public comment

- Adjourn:
  - Motion: Gonet
  - Second: Severin

PUBLIC NOTICE
of Meeting

Flue Gas Desulfurization Task Force

Wednesday, October 10, 2018
10 a.m. – Noon

Illinois EPA
1021 North Grand Avenue East
Springfield, IL

AGENDA

1. Welcome and introduction of Task Force members

2. Approval of 9/26/18 meeting minutes

3. Presentations

    - Summary of Coal Industry: Tom Benner, IDNR
    - Economic Considerations: Doug Brown, CWLP
    - JET, Inc.: David Repp

4. Future topics for discussion

5. Scheduling of November Task Force meeting

6. Opportunity for public comment and questions

7. Adjourn

MINUTES of the

FLUE GAS DESULFURIZATION TASK FORCE MEETING

Held on OCTOBER 10, 2018

- Meeting commenced at 10:03 a.m.

- Task Force members present:
  - Director Messina, IEPA
  - Senator Schimpf
  - Representative Bourne (phone)
  - Senator Fowler (phone)
  - Representative Severin (phone)
  - Tom Benner, IDNR
  - Doug Brown, CWLP
  - William Matuscak, ADM
  - Phil Gonet, Illinois Coal Association (phone)

- Approval of 9/26/18 meeting minutes:
  - Motion: Tom Benner
  - Second: Senator Schimpf

- Presentations:
  - Summary of Coal Industry: Tom Benner, IDNR - Overview and discussion of Illinois coal mines including production, consumption and reserves, and coal-fired plants
  - Economic Considerations: Doug Brown, CWLP - Overview and discussion of market conditions, barriers and considerations, and new technology
  - JET, Inc.: David Repp - Overview and discussion of Ammonia Based Desulfurization

- Discussion:
  - Senator Schimpf: questioned reach out to Illinois Farm Bureau, as the JET model is based on demand for new fertilizer.
    - JET: No reach out to IFB, but performed own market research.
  - Matuscak: questioned typical term of agreement.
    - JET: 8-10 years.
  - Gonet: requested that the Task Force support the exploration of JET's proposal and make it the foundation of the Task Force report.
  - JET: willing to host Illinois delegation in China to tour plants and view technology.

- Suggestions for future meetings:
  - Bourne: questioned the current legislative and regulatory environment including any regulatory hurdles.
  - Gonet: requested the IEPA Bureau of Air staff verify numbers and discuss permitting.

- No public comment

- Next Meeting:
  - Wednesday, October 24, 2018
10am
Illinois EPA, Springfield

- Adjournment:
  - Motion: Senator Schimpf
  - Second: Tom Benner

PUBLIC NOTICE

of Meeting
Flue Gas Desulfurization Task Force
Wednesday, October 24, 2018
10 a.m. – Noon
Illinois EPA
1021 North Grand Avenue East
Springfield, IL

AGENDA

1. Welcome and introduction of Task Force members
2. Approval of 10/10/18 meeting minutes
3. Presentation and discussion of draft report
4. Scheduling of November Task Force meeting
5. Opportunity for public comment and questions
6. Adjourn

DRAFT MINUTES of the
FLUE GAS DESULFURIZATION TASK FORCE MEETING

October 24, 2018

- Meeting commenced at 10:05am

- Task Force members present:
  - Director Messina, IEPA
  - Senator Schimpf
  - William Matuscak, ADM
  - Dan Wheeler (for Tom Benner), DNR
  - Representative Bourne (phone)
  - Representative Severin (phone)
  - Representative Chapa LaVia (phone)
  - Phil Gonet, Illinois Coal Association (phone)

- Approval of 10/10/18 meeting minutes:
  - Motion: Senator Schimpf
  - Second: William Matuscak

- Presentation and discussion of draft report:
  - Gonet: commented that draft lays out the issues and challenges well, but suggested the Task Force consider inviting NRG or Vistra to comment.
  - Schimpf: asked how we might incorporate public comment.
    - Messina: we will add a section to reflect that the meetings were public noticed, and opportunity was provided for public comment.
    - Gonet: final report will be recommendations to the General Assembly and not necessarily final action; public will still have opportunity to be involved in any potential legislation.
    - Bourne: on other Task Forces, we have viewed the report as a document to the public that outlines the current state of affairs on an issue and directs the General Assembly to act as necessary.
    - ChapaLaVia: concurs with Rep. Bourne.

- Scheduling of next meeting:
  - Tentatively plan for November 13th at 2pm, IEPA will secure a room in either the Capitol or Stratton Building.

- Public Comment:
  - David Repp, JET: suggests that the Executive Summary include pathways for legislation or roadmap for Illinois to support alternative technologies.
    - Julie Armitage, IEPA: JET also needs to be effectively communicating this info to the facilities; it is ultimately up to them to see if it makes technical and economic sense. It is important to remember that all of the EGUs are currently in compliance.
    - Gonet: understand Julie's point, but we should do what we can to save the existing coal fleet by lowering the cost to comply. The Task Force should encourage the EGUs to explore alternative technology.

- Adjournment:
  - Motion: Senator Schimpf
  - Second: Phil Gonet

PUBLIC NOTICE
of Meeting

Flue Gas Desulfurization Task Force

Monday, November 19, 2018
2:00 p.m. - 3:00 p.m.

Illinois EPA
1021 North Grand Avenue East
Springfield, IL
(Via Conference Call)

AGENDA

1. Welcome and introduction of Task Force members
2. Approval of 10/24/18 meeting minutes
3. Discussion of draft report
4. Scheduling of final Task Force meeting
5. Opportunity for public comment and questions
6. Adjourn

MINUTES of the

FLUE GAS DESULFURIZATION TASK FORCE TELECONFERENCE MEETING

Held on NOVEMBER 19, 2018

- Meeting commenced at 2:03pm.

- Task Force members present by phone:
  - Director Messina, IEPA
  - Senator Schimpf
  - Senator Fowler
  - Representative Bourne
  - Representative Chapa LaVia
  - Tom Benner, IDNR
  - Doug Brown, CWLP
  - William Matuscak, ADM

- Approval of 10/24/18 meeting minutes:
  - Motion: Tom Benner
  - Second: Representative Bourne

- Discussion of draft report:
  - Director Messina: Staff will include in Executive Summary information related to the Task Force and its meetings (public notice, membership, etc). Comments from JET and Peabody, as well as the presentations will be included in the Appendix.
  - Discussion of JET comments:
    - Director Messina: staff will also include JET's third-party report in the Appendix.
  - Discussion of Peabody comments:
    - Rep. Bourne: the legislative intent was to focus on Illinois EGU.
    - Sen. Schimpf: good to include that Illinois coal is being used in out of state EGUs; we don't want to do anything to discount Illinois companies' work in other states.

- Scheduling of final Task Force meeting:
  - Director Messina: Look at week of December 10th for final Task Force meeting and vote on final report.

- No public comment

- Adjournment:
  - Motion: Senator Schimpf
  - Second: Tom Benner

PUBLIC NOTICE
of Meeting

Flue Gas Desulfurization Task Force

Monday, December 17, 2018
2:00 p.m.

Illinois EPA
1021 North Grand Avenue East
Springfield, IL

AGENDA

1. Welcome and introduction of Task Force members
2. Approval of 11/19/18 meeting minutes
3. Discussion of draft report
4. Opportunity for public comment and questions
5. Vote on approval of report
6. Adjourn

MINUTES of the

FLUE GAS DESULFURIZATION TASK FORCE TELECONFERENCE MEETING

Held on DECEMBER 17, 2018

- Meeting commenced at 2:03pm.

- Task Force members present:
  - Director Messina, IEPA
  - Representative Bourne
  - Phil Gonet, IL Coal Association
  - William Matuscak, ADM
  - Tom Benner, IDNR
  - Senator Schimpf (phone)
  - Representative Chapa LaVia (phone)
  - Doug Brown, CWLP (phone)

- Approval of 11/19/18 meeting minutes:
  - Motion: Phil Gonet
  - Second: William Matuscak

- Discussion of draft report:
  - Director Messina: IEPA received comments from JET, Vistra, Peabody, and the IL Coal Association. The approach of IEPA staff drafting the report was to incorporate opposing viewpoints into the report, and not to be the ultimate arbiter.
  - Phil Gonet: asked staff to identify the section of the report that incorporated alternative comments on the coast of PRB coal.
    - William Matuscak: cost of coal is a moving target and depends on many variables, including the company, time of year, supply chain, and transportation costs. Believes the report provides a fair assessment.

- No public comment

- Approval of Task Force Report
  - Motion: Tom Benner
  - Second: William Matuscak

- Adjournment:
  - Motion: Representative Bourne
  - Second: Tom Benner

II. Presentations to the FGD Task Force

1. Flue Gas Desulfurization for Illinois – Illinois EPA
2. Summary of the Illinois Coal Industry – Illinois DNR
3. Economic Considerations – CWLP
4. Ammonia Based Desfulfurization – JET

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 (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

Plant	Size	Control	Coal	Owner
Baldwin – 3 Units	2032 MW	**Dry Lime FGD**	PRB	Vistra
Havana – 1 Unit	493 MW	**Dry Lime FGD**	PRB	Vistra
Hennepin – 2 Units	326 MW	Low Sulfur Coal	PRB	Vistra
Coffeen – 2 Units	984 MW	**Wet Limestone FGD**	PRB	Vistra
Duck Creek – 1 Unit	484 MW	**Wet Limestone FGD**	PRB	Vistra
ED Edwards – 2 Units	728 MW	Low Sulfur Coal	PRB	Vistra
Joppa Steam – 6 Units	1364 MW	Low Sulfur Coal	PRB	Vistra
Kincaid – 2 Units	1297 MW	**Dry Sorbent Injection**	PRB	Vistra
Newton – 1 Unit	748 MW	Low Sulfur Coal	PRB	Vistra
Powerton – 4 Units	1673 MW	**Dry Sorbent Injection**	PRB	Midwest Generation
Waukegan – 2 Units	756 MW	Low Sulfur Coal	PRB	Midwest Generation
Will County – 1 Unit	534 MW	Low Sulfur Coal	PRB	Midwest Generation
CWLP – 4 Units	567 MW	**Wet Limestone FGD**	Illinois	Municipal
Prairie State – 2 Units	1664 MW	**Wet Lime FGD**	Illinois	Independent
SIPC Marion - 2 Units	312 MW	**Fluidized Bed Limestone/Wet Lime FGD**	Illinois	Independent

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.

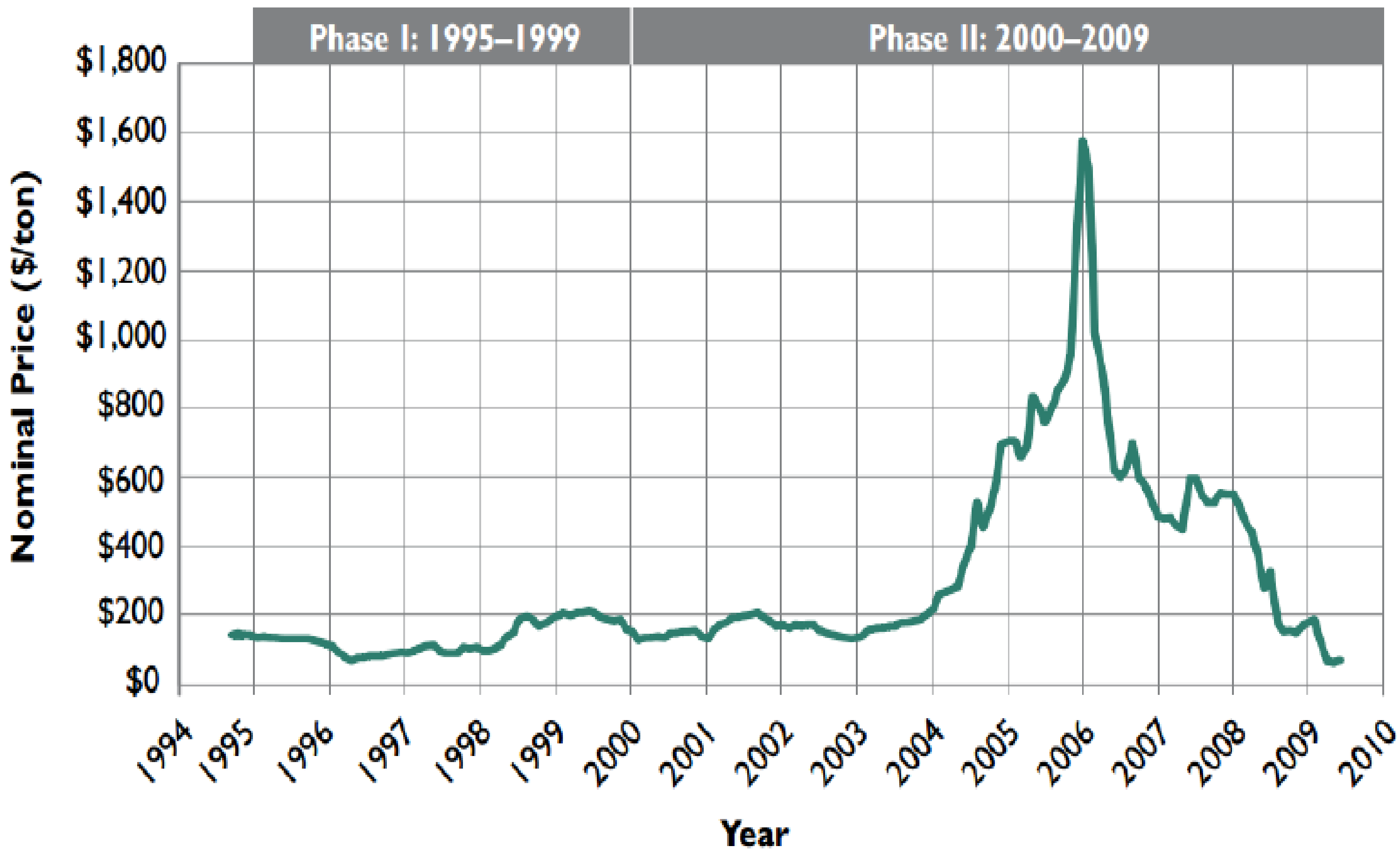
Federal Regulations Limiting SO_2 Emissions

- SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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:
  - Bituminous coal
  - Typical heating value around 11,800 mmBtu/pound
  - Recent spot prices around $32/ton – August 2018
  - SO_2 emissions in the range of 3 - 5 lb/mmBtu upon combustion
- Powder River Basin (PRB) Coal:
  - Originates in the Powder River Basin in Wyoming and Montana
  - Sub-bituminous coal
  - Typical heating value around 8,800 mmBtu/lb
  - Recent spot prices around $12/ton – August 2018
  - Transportation costs by rail to Illinois around $21/ton
  - 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 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

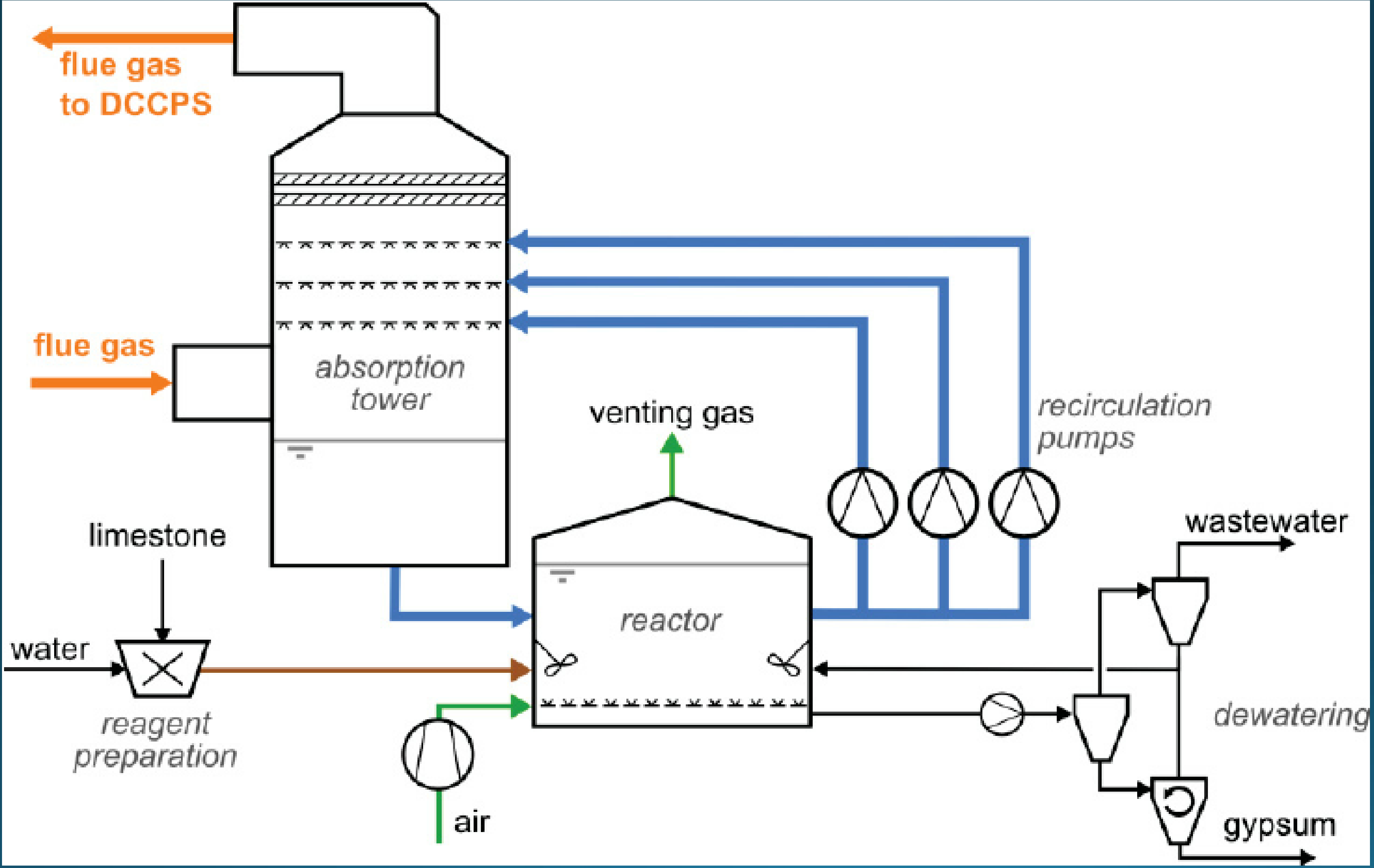
- Wet scrubber systems achieve the highest SO_2 control efficiencies, typically in a range of 90 – 95%, but can be higher.
- Wet scrubber systems are typically the most expensive types of FGD because of the high capital cost.
- Additional annual operation and maintenance costs include the cost of limestone 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.

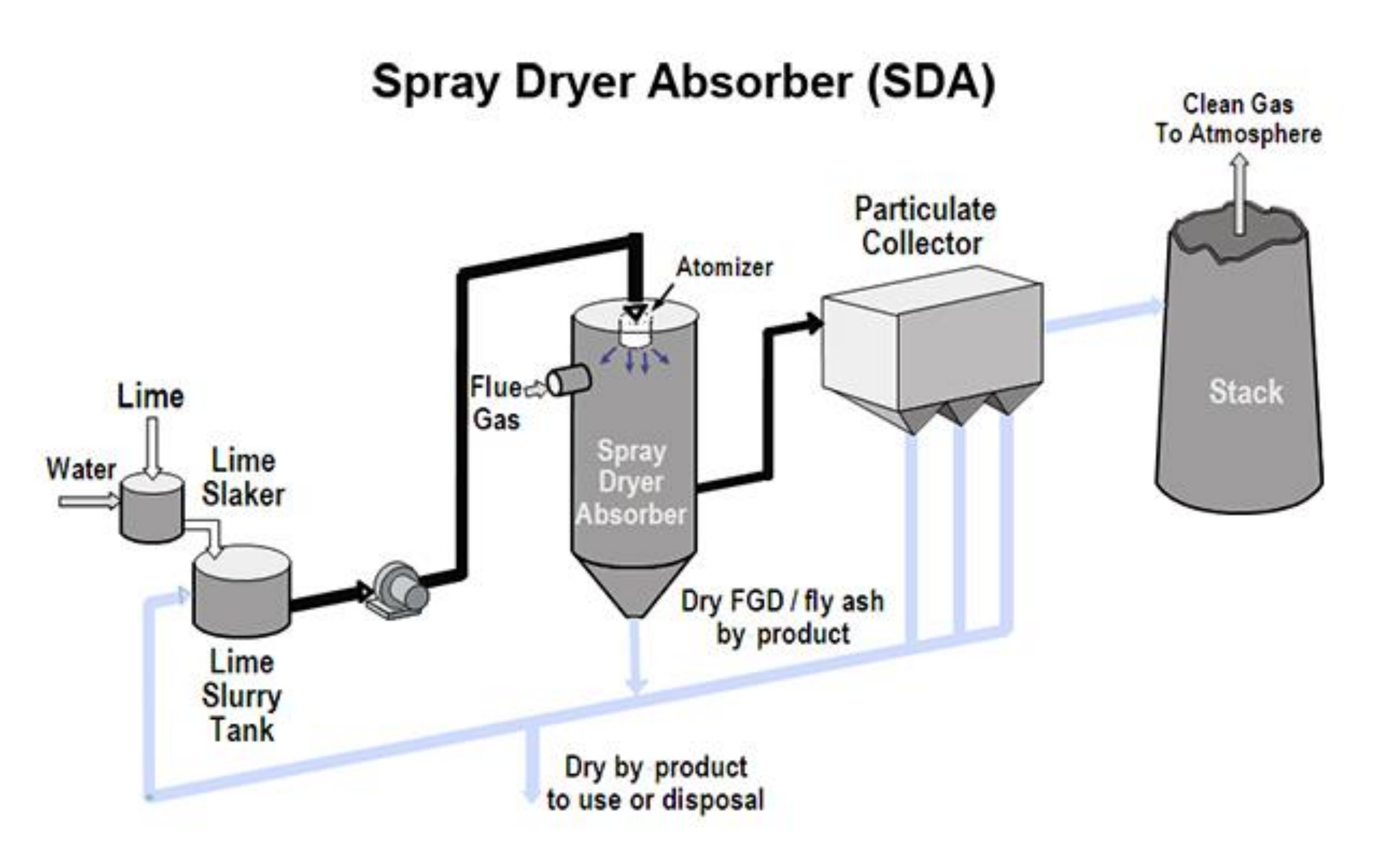
Wet Scrubber Diagram



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.

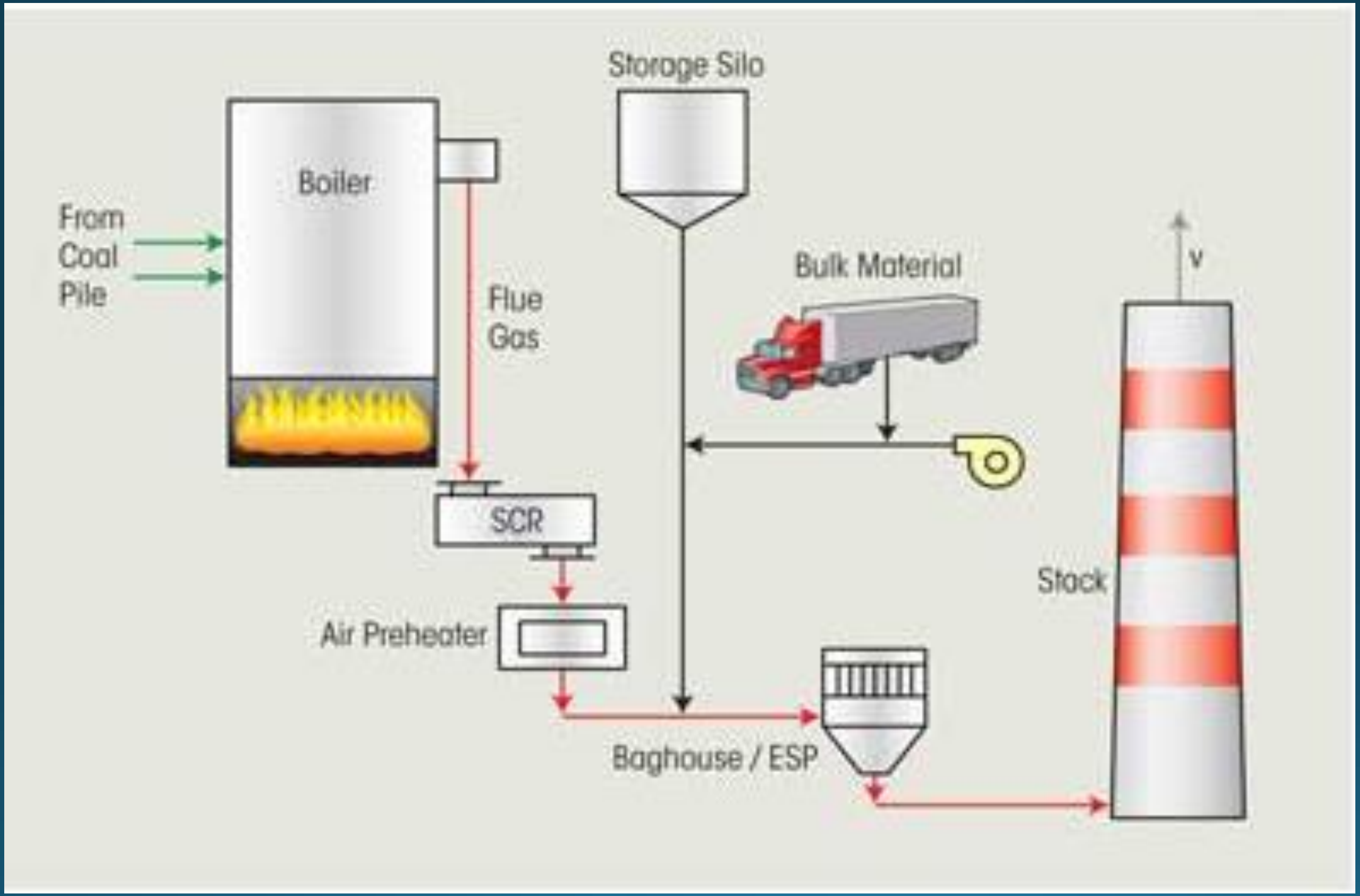
Dry Scrubber Diagram



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 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

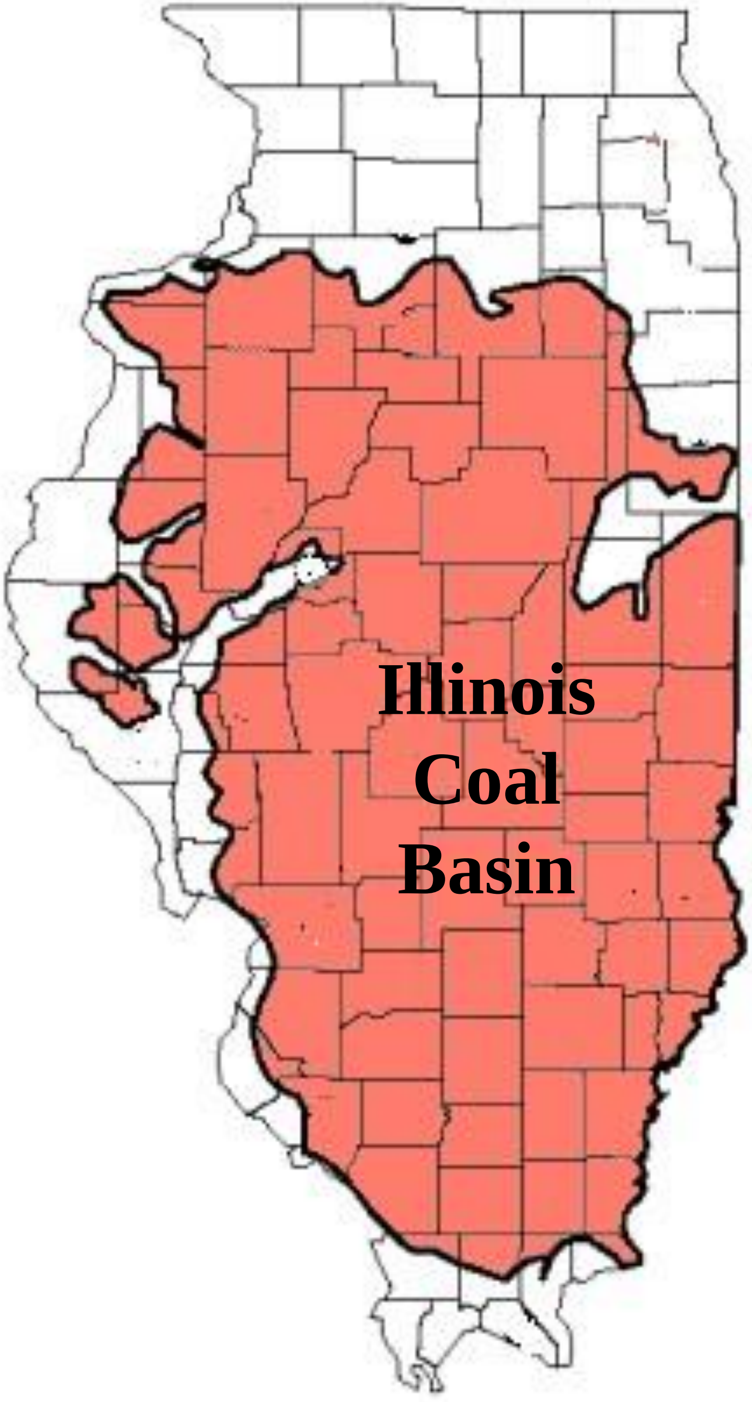
- Cost estimates and control efficiency estimates vary greatly depending upon the source of information, the age of the information, and a variety of conditions at the units to be controlled.
- Control cost data for scrubbers is from USEPA and is in 2001 dollars. More updated information was not available.
- 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.

Summary of the Illinois Coal Industry

Tom Benner
Director
Office of Mines and Minerals
Illinois Department of Natural Resources

Illinois Coal Reserves

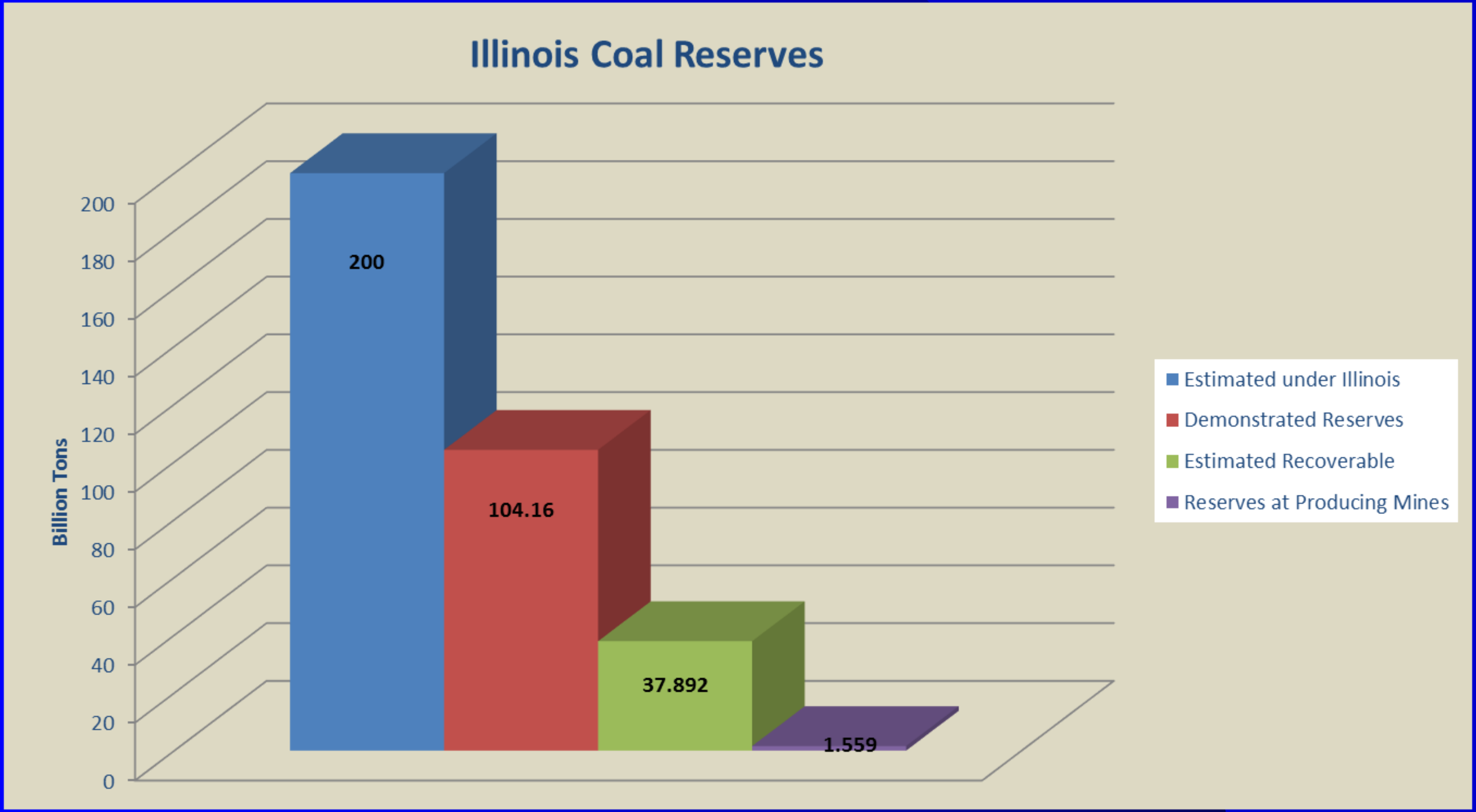
- Coal underlies 65 percent of Illinois.
- Illinois has the largest reported bituminous coal resources of any state in the U.S.



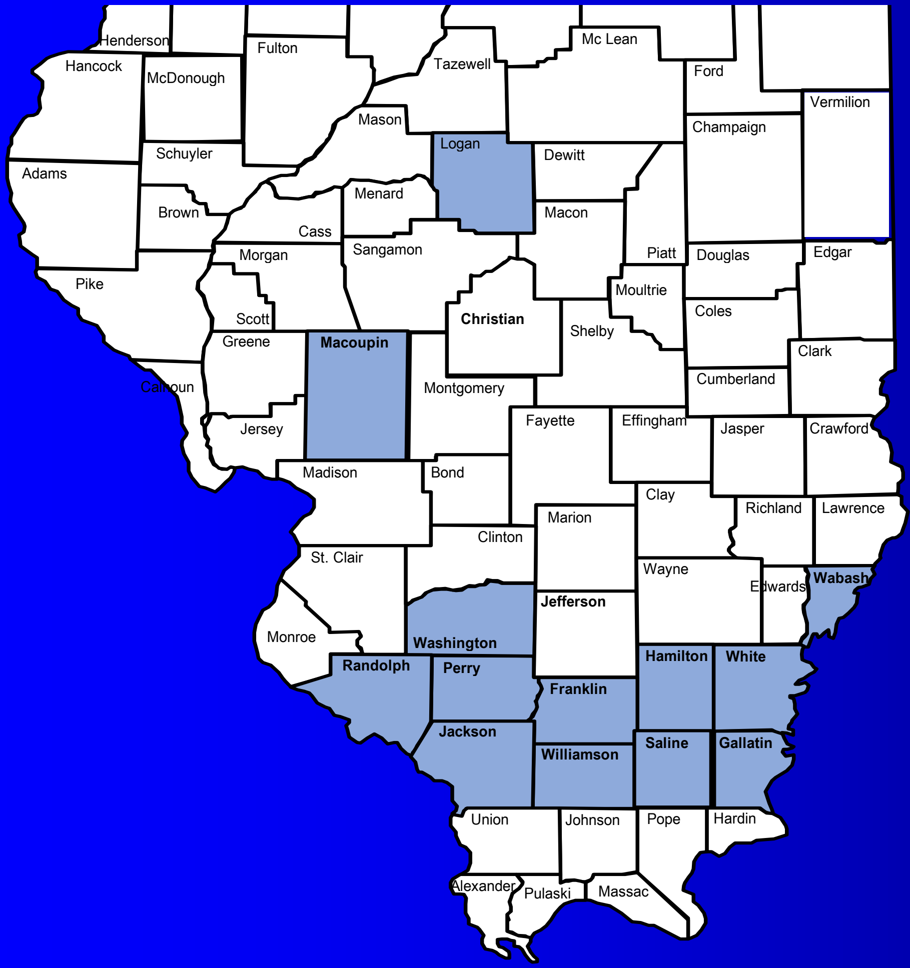
Abundant Bituminous Coal Resources

- 38 billion tons of recoverable coal reserves in Illinois, ¼ of the nation's bituminous reserves
- 37,000 square miles
- 85% of production comes from the Herrin No. 6 and the Springfield No. 5
- Seams average 4.5 ft to 8 ft in thickness
- Energy values between 10,200 – 14,000 Btu/lb
- Illinois coal reserves contain more Btu than the oil reserves of Saudi Arabia and Kuwait

Abundant Reserves



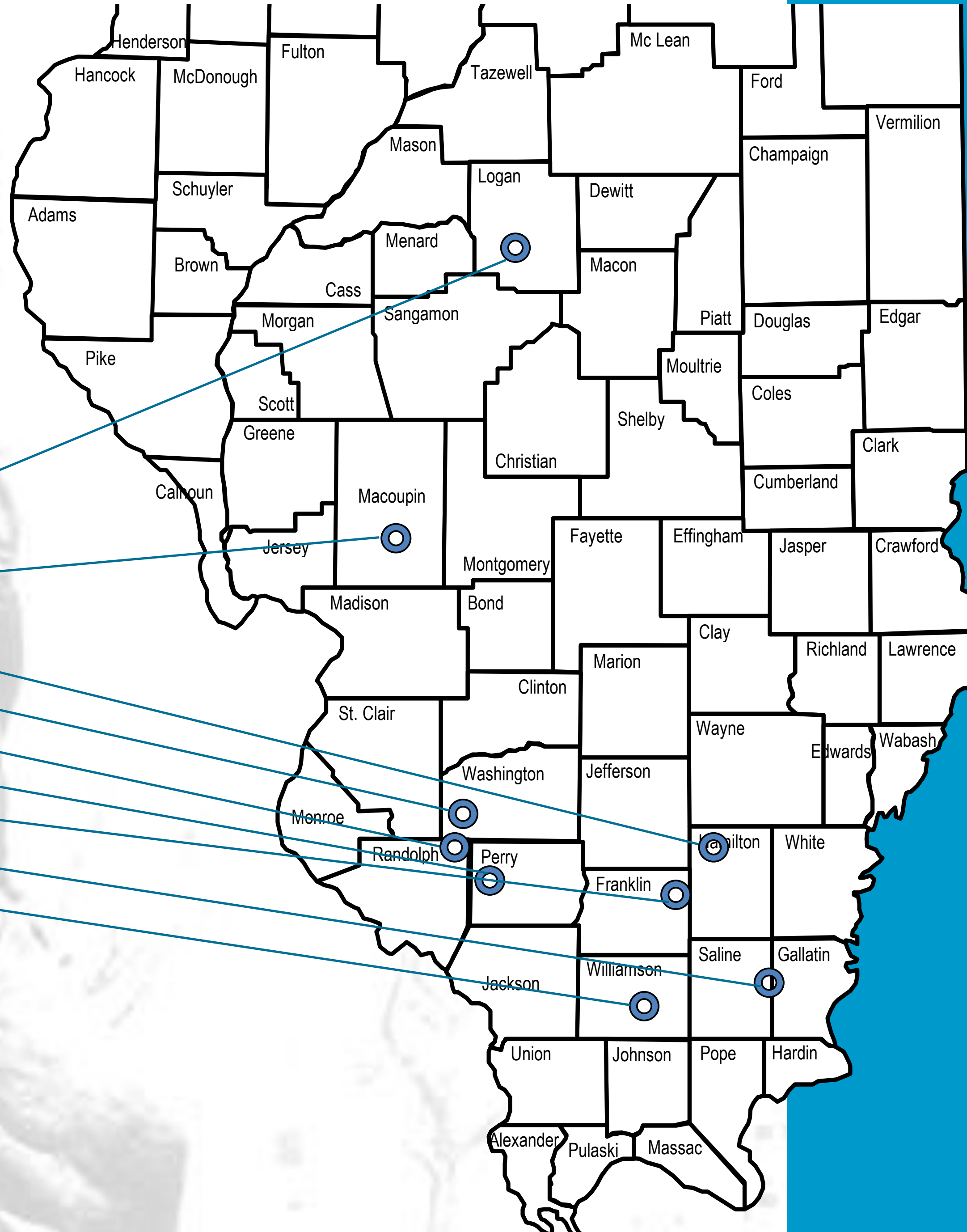
2016 Coal Production by County



Coal Production by County		
County	No. of Mines	Production(MT)
Franklin	1	11.4
Washington	1	5.9
Williamson	1	5.4
Saline	2	5.3
Perry	3	3.5
Hamilton	1	3.0
Randolph	3	2.4
Macoupin	1	2.0
White	1	1.9
Logan	1	1.7
Wabash	1	0.30
Gallatin	1	0.24
Jackson	1	0.003

Coal Mines in Illinois

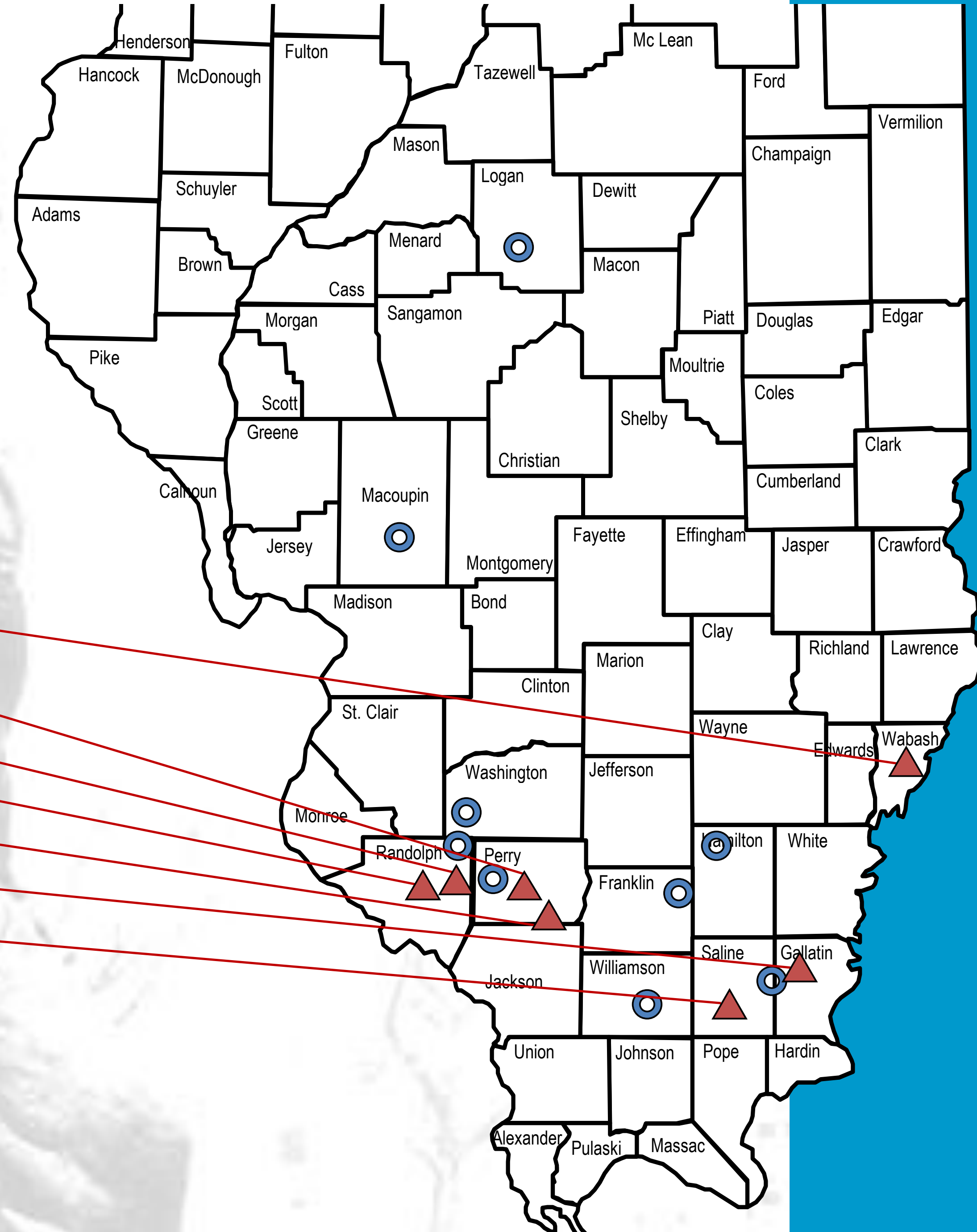
- Underground mines
  - **Viper**
  - **Shay**
  - **Hamilton Cty**
  - **Lively Grove**
  - **Gateway North**
  - **Prairie Eagle UG**
  - **M-Class Mining**
  - **Wildcat Hills UG**
  - **Mach Mining**



Coal Mines in Illinois

- Underground mines
- Surface mines

Friendsville
Golden Eagle
Black Hawk
Hawkeye
Red Hawk
Cottage Grove
Eagle River



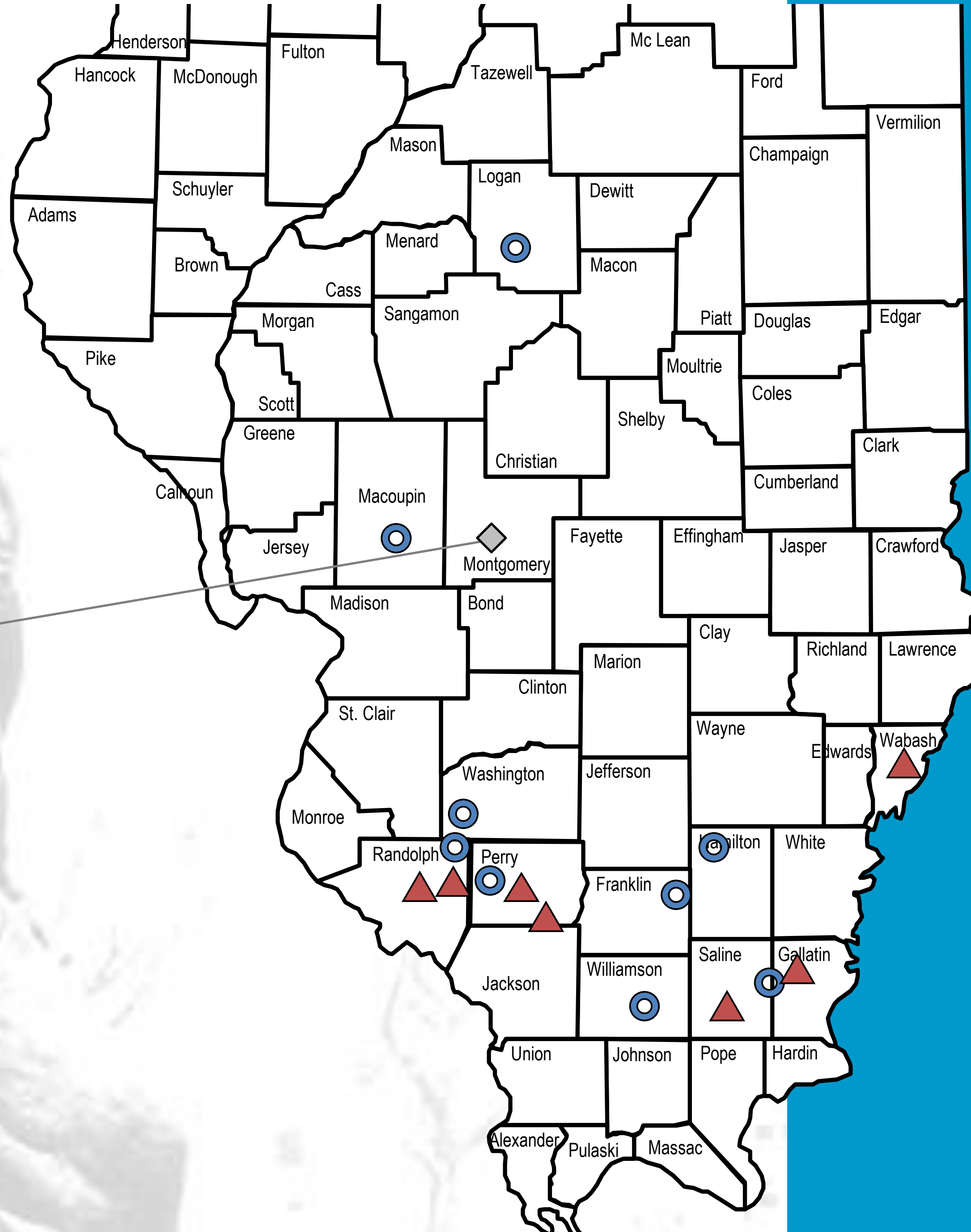
Coal Mines in Illinois

Underground mines

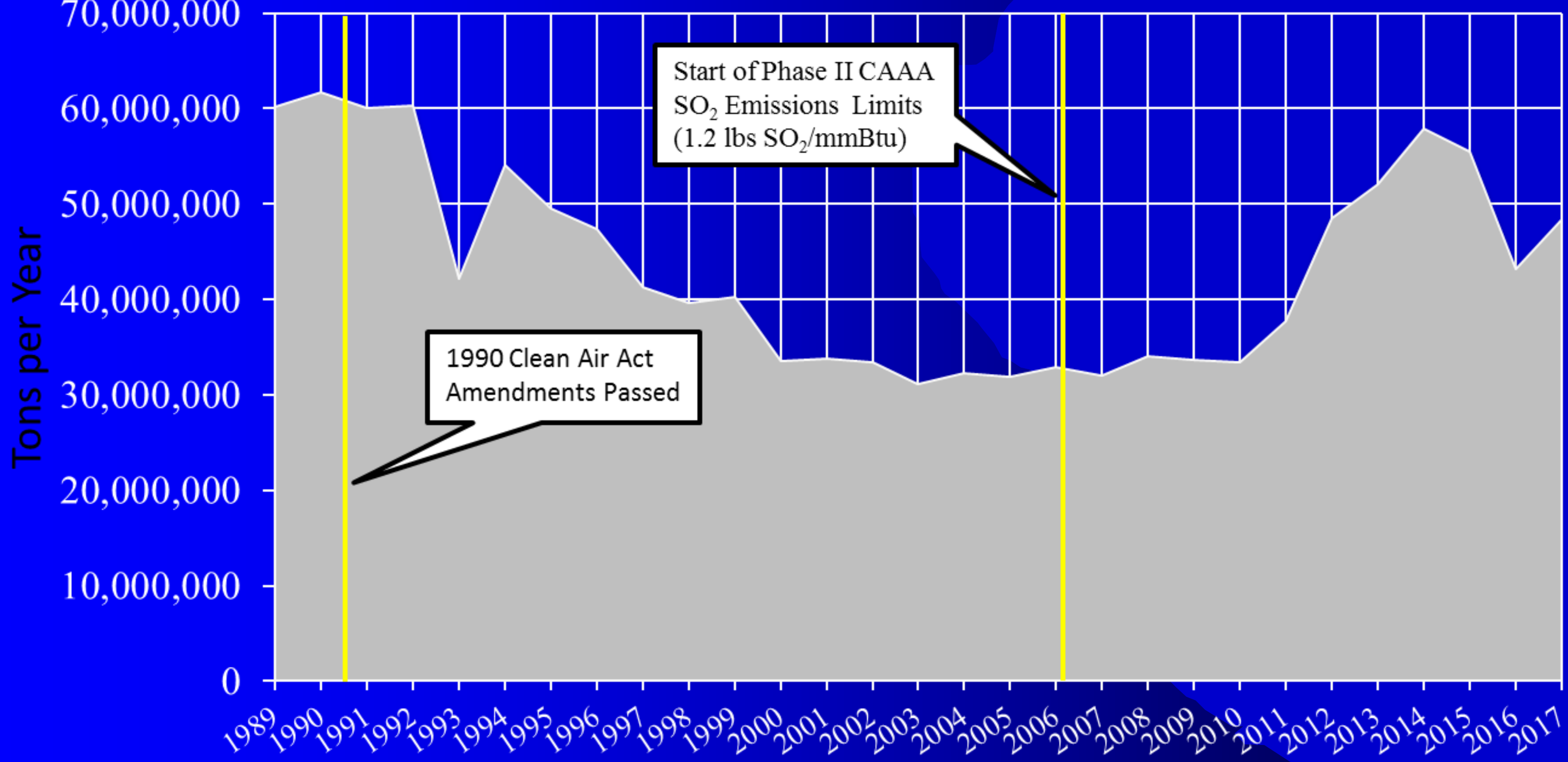
Surface mines

Idled mines

Deer Run



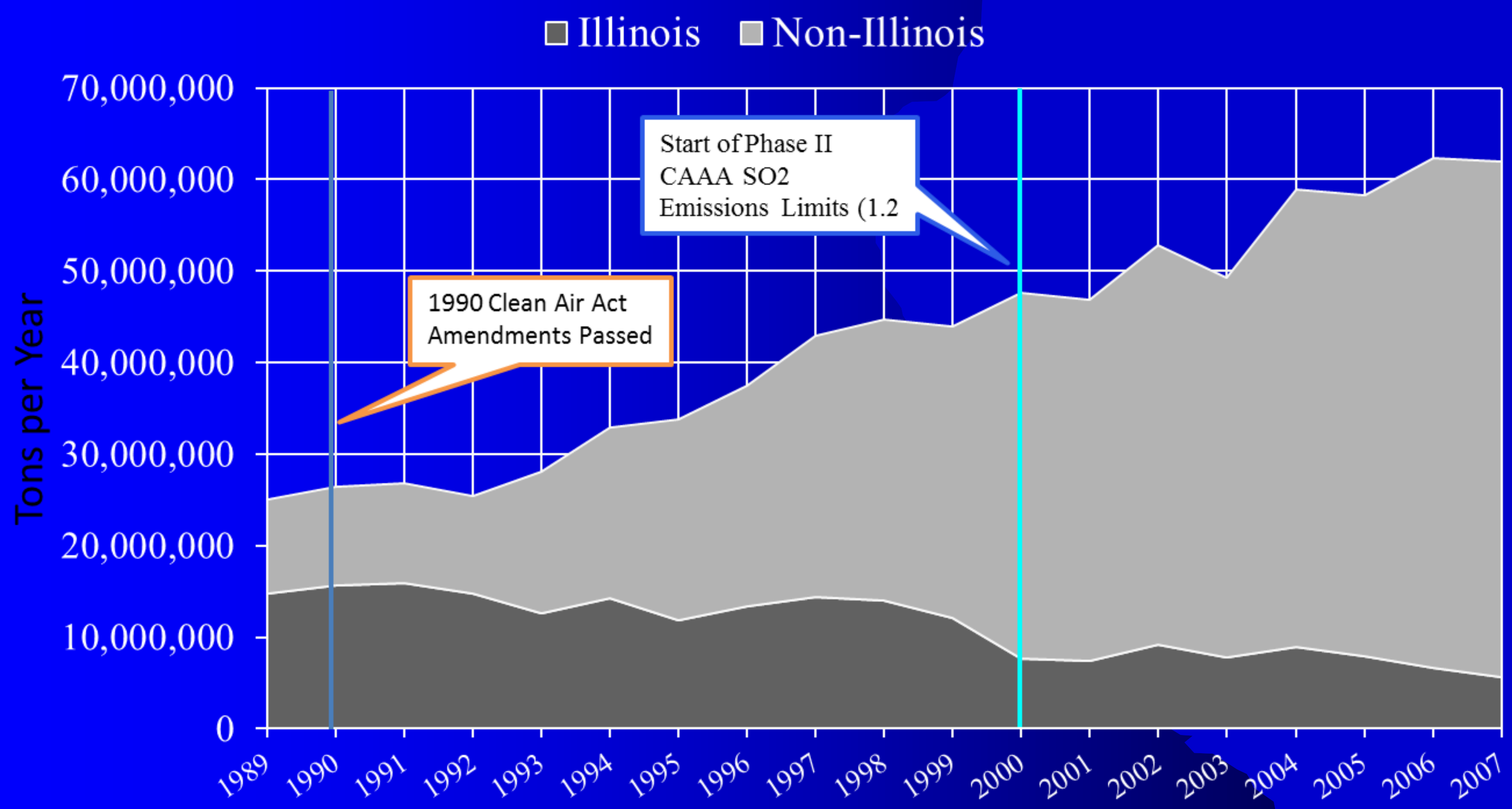
Illinois Coal Production



Illinois Coal: Production & Consumption

Year	Production	Consumption
1989	60,131,053	14,740,220
1990	61,657,068	15,598,500
1991	60,035,515	15,852,220
1992	60,331,826	14,817,600
1993	42,143,821	12,595,890
1994	54,026,365	14,313,820
1995	49,537,182	11,879,020
1996	47,311,477	13,383,110
1997	41,247,632	14,424,820
1998	39,639,334	13,994,870
1999	40,315,208	12,086,770
2000	33,541,271	7,649,960
2001	33,793,509	7,465,960
2002	33,445,848	9,229,430
2003	31,135,859	7,821,690
2004	32,279,112	8,943,260
2005	31,939,625	7,975,060
2006	32,962,446	6,610,990
2007	32,015,323	5,690,400

Consumption of Coal at Illinois Plants

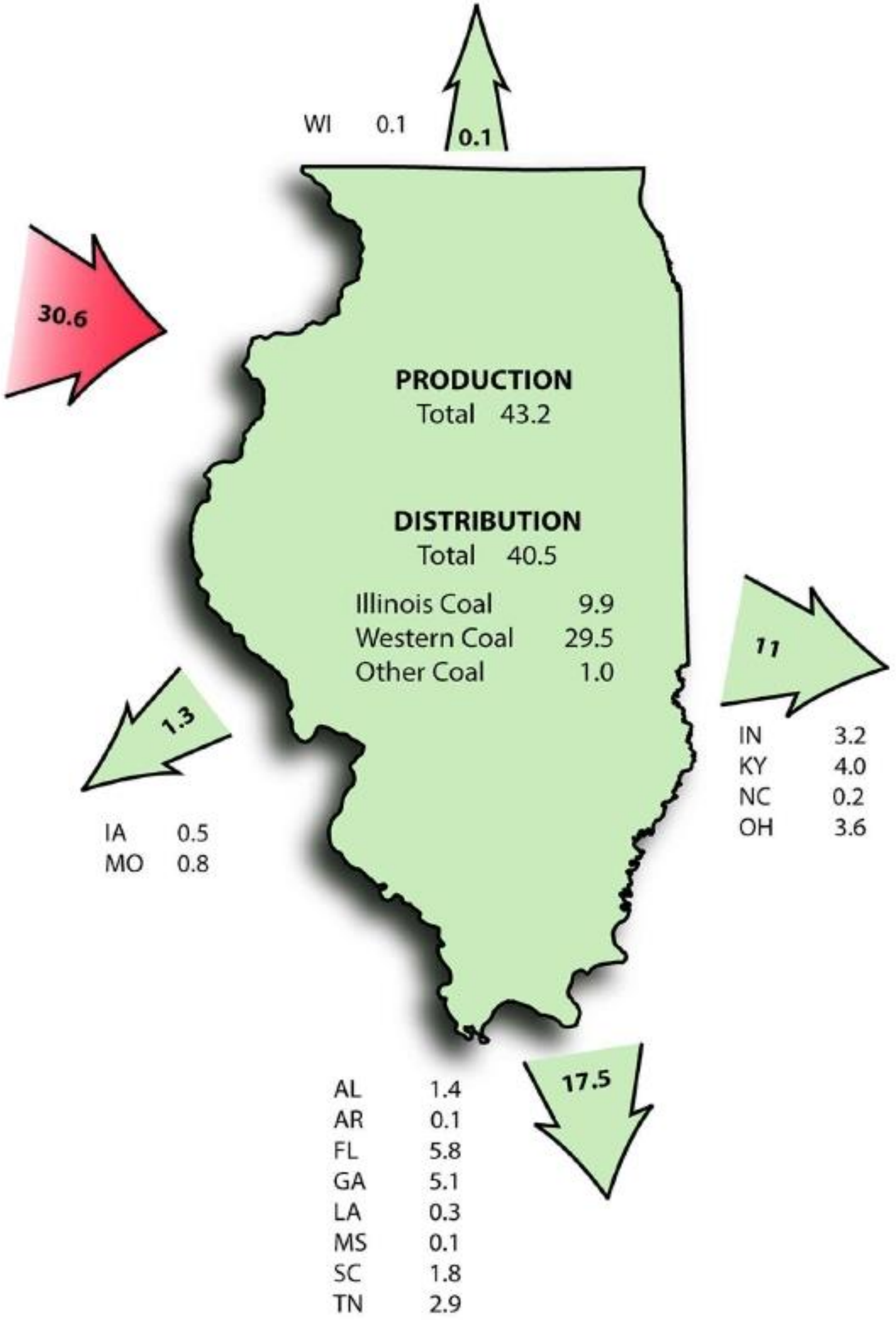


Consumption of Coal at Illinois Plants

Year	Illinois	Non-Illinois
1989	14,740,220	10,318,480
1990	15,598,500	10,857,680
1991	15,852,220	10,960,390
1992	14,817,600	10,631,110
1993	12,595,890	15,497,460
1994	14,313,820	18,596,130
1995	11,879,020	21,866,860
1996	13,383,110	24,093,640
1997	14,424,820	28,457,680
1998	13,994,870	30,687,380
1999	12,086,770	31,803,480
2000	7,649,960	39,988,410
2001	7,465,960	39,443,060
2002	9,229,430	43,587,130
2003	7,821,690	41,439,300
2004	8,943,260	49,968,650
2005	7,975,060	50,306,750
2006	6,610,990	55,748,710
2007	5,690,400	56,240,460

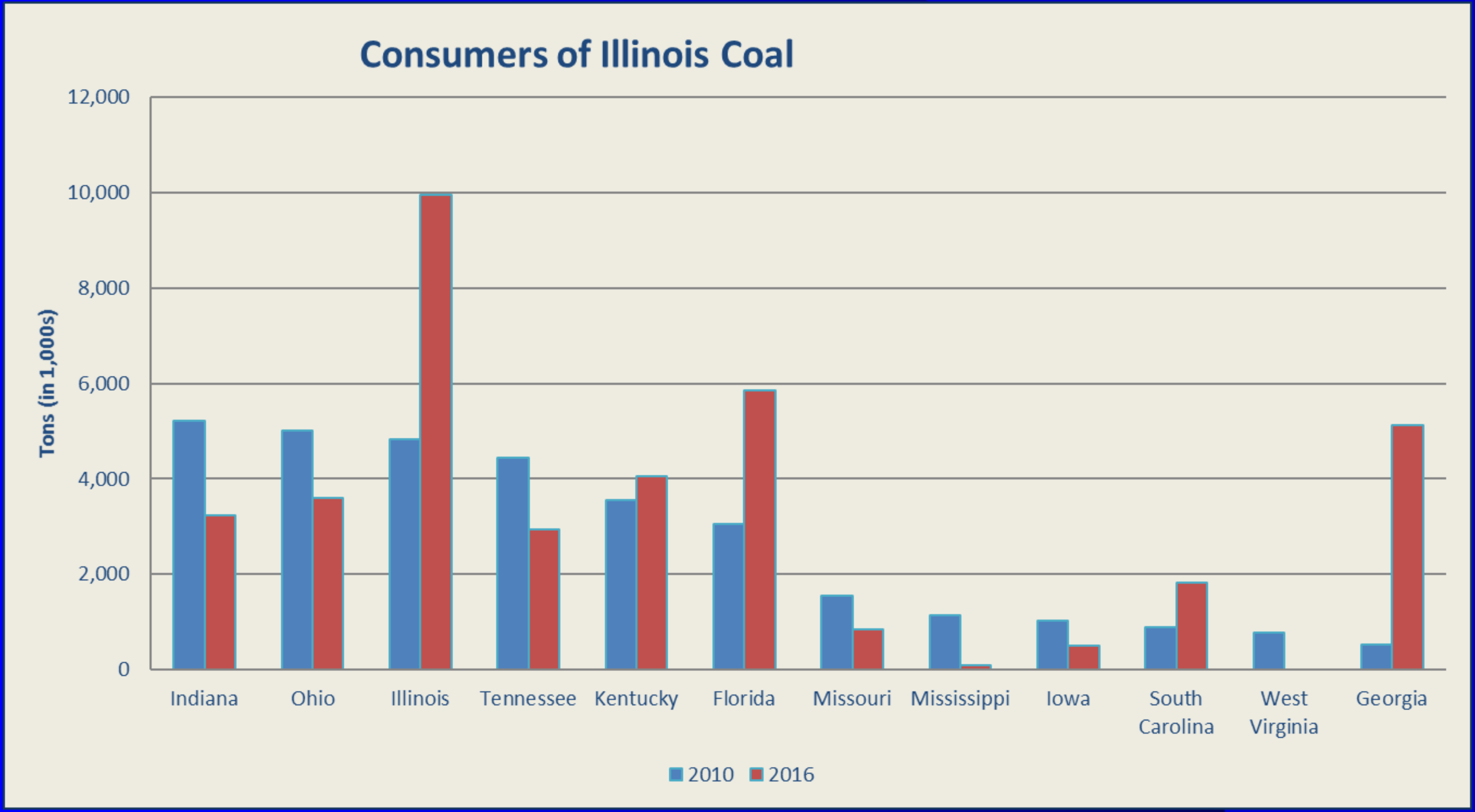
2016 Coal Balance

(in million tons)



Source: EIA Domestic Coal Distribution 2016

Illinois Coal Use by State



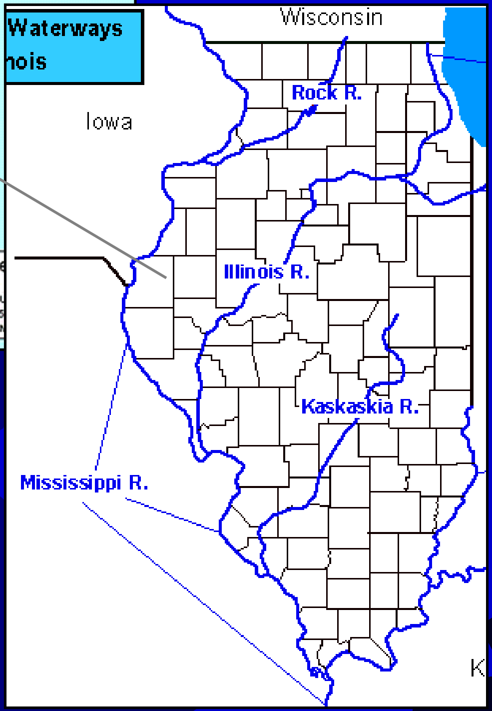
Coal Properties

Counties	Moisture (%)	Ash (%)	Sulfur (%)	Calorific Value	
				Btu/lb.	kcal/kg
Herrin Coal					
La Salle, Grundy	13-16	7-11	3-5	10,500-11,400	5,834-6,334
Bureau, Stark, Henry, Knox	6-20	8-13	3-5	9,700-10,300	5,389-5,723
Peoria, Fulton	15-19	8-13	2-4	10,000-10,700	5,556-5,945
Sangamon, Macoupin	12-16	9-11	3-5	10,400-10,900	5,778-6,056
Christian, Montgomery, Bond, Madison	12-14	9-11	3-5	10,500-11,000	5,834-6,112
Douglas, Vermilion	4-16	8-12	1-3	10,400-11,100	5,778-6,167
Clinton, St. Clair	10-13	9-12	1-4	10,000-10,700	5,556-5,945
Marion, Washington, Randolph, Perry	8-12	9-13	1-4	10,800-11,300	6,000-6,278
Springfield Coal					
Peoria, Fulton, Tazewell, Schuyler	14-18	9-12	2-4	10,100-10,800	5,612-6,000
McLean, Logan, Menard, Sangamon	13-17	9-12	3-5	10,400-11,000	5,778-6,112
Macon, Shelby	12-16	8-12	3-4	10,500-11,100	5,834-6,167
Edgar	10-12	8-10	3-4	10,400-11,000	5,778-6,112
Randolph, Perry	8-13	9-12	4-5	11,000-11,400	6,112-6,334
Jackson	8-9	1	3-4	11,600-11,800	6,445-6,556
Gallatin, Saline, Williamson	5-7	2-5	2-5	11,900-12,500	6,612-6,945
Gallatin (Eagle Valley)	4-5	3-4	3-4	12,400-12,700	6,889-7,056

Common Emission Control Technology

Technology to Control Emissions	
Pollutant addressed	**Existing control technologies to address toxic pollutants**
Mercury	Selective Catalytic Reduction (SCR) with Flue-gas Desulfurization (FGD), Activated Carbon Injection (ACI), ACI with Fabric Filter (FF) or Electrostatic Precipitators (ESP)
Non-mercury metals	FF, ESP
Acid gases	FGD, Dry Sorbent Injection (DSI), DSI with FF or ESP
Sulfur dioxide	FGD, DSI
NOx	Low-NOx burners; SCR
Ultra-fine particulate matter	FF, wet ESP

Truck, Barge & Rail Transportation

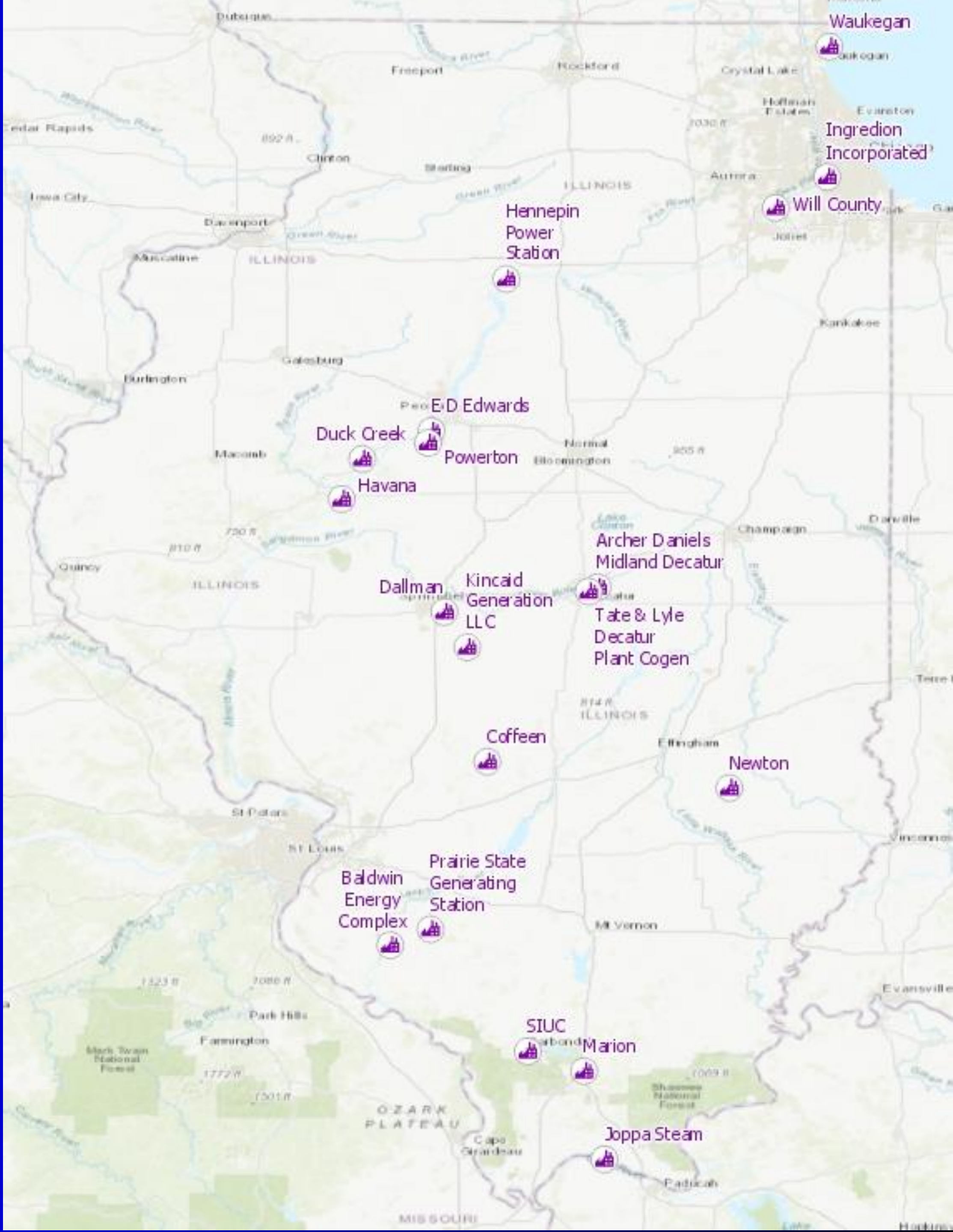


Current Rail System

- Illinois is 2nd only to Texas in the number of freight railroad miles within its borders.
- Seven Class I railroads with 5,830 miles of track excluding trackage rights
- Four regional railroads, 12 local railroads, & 18 switching and terminal railroads operate 1,336 miles of track

http://www.aar.org/PubCommon/Documents/AboutTheIndustry/RRState_IL.pdf?states=RRState_IL.pdf

Illinois Coal Plants
2016



Coal Power Plants
13.4 Gigawatt nameplate capacity

Major Coal Industrial Plants
447.1 Megawatts nameplate capacity

Illinois Power Plants

Coal-Fueled Electric Power Plants[1]

Plant operator Map no., plant (year built)	County	Generation capacity (MW)	Coal purchased in 2016 (1,000 tons)	Origin of coal purchased in 2016 (1,000 tons): Illinois	Other IB[2]	Western	Possible terminating transportation[3]
City of Springfield							
1. Dallman I-IV (1968;1972;1978;2009)	Sangamon	617	949	949			
Dynegy Kincaid Generation							
2. Kincaid (1967; 1968)	Christian	1,319	2,532			2,532	IMRR
Dynegy Midwest Generation Inc							
3. Baldwin (1970)	Randolph	1,895	5,512			5,512	CN
4. Havana (1978)	Mason	488	1,550			1,550	IMRR, BG
5. Hennepin (1953; 1959)	Putnam	306	735			735	BG
6.Wood River (1954; 1964)[4]	Madison	473	109			109	NS
Electric Energy, Inc.							
7. Joppa (1953)	Masaac	1,100	1,591			1,591	UP
Illinois Power Generating Co.							
8. Coffeen (1965)	Montgomery	1,005	2,800			2,800	NS
9. Newton (1977)	Jasper	617	1,316			1,316	CN
Illinois Power Resources Generating, LLC							
10. Duck Creek (1976)	Fulton	441	1,179			1,179	BNSF, TK
11. E. D. Edwards (1968;1972)	Peoria	644	1,467			1,467	UP
Midwest Generation EME, LLC							
12. Joliet 9 (1959)[5]	Will	360	106			106	CN, BNSF, UP, EJE
13. Powerton (1972; 1975)	Tazewell	1,538	2,766			2,766	IMRR
14. Waukegan (1952; 1958; 1962)	Lake	682	886			886	UP
15. Will County (1955; 1957; 1963)	Will	598	1,406				BG, EJE
Prairie State Generating Company							
16. Prairie State Generating Station (2012)	Washington	1,766	6,070	6,070		1,406	mine mouth
Southern Illinois Power Cooperative							
17. Marion (1963;1978; 2003)	Williamson	422	972	958	14		TK, UP

1 Sources: U.S. Dept. of Energy, Energy Information Administration (EIA), Fuel Receipts and Cost, EIA-923 Schedule 2, and EIA-860.
2 IB, Illinois Basin.
3 See Transportation and Rail Service Codes for definitions of abbreviations.
4 Closed May 2016.
5 Converted to natural gas 2016.

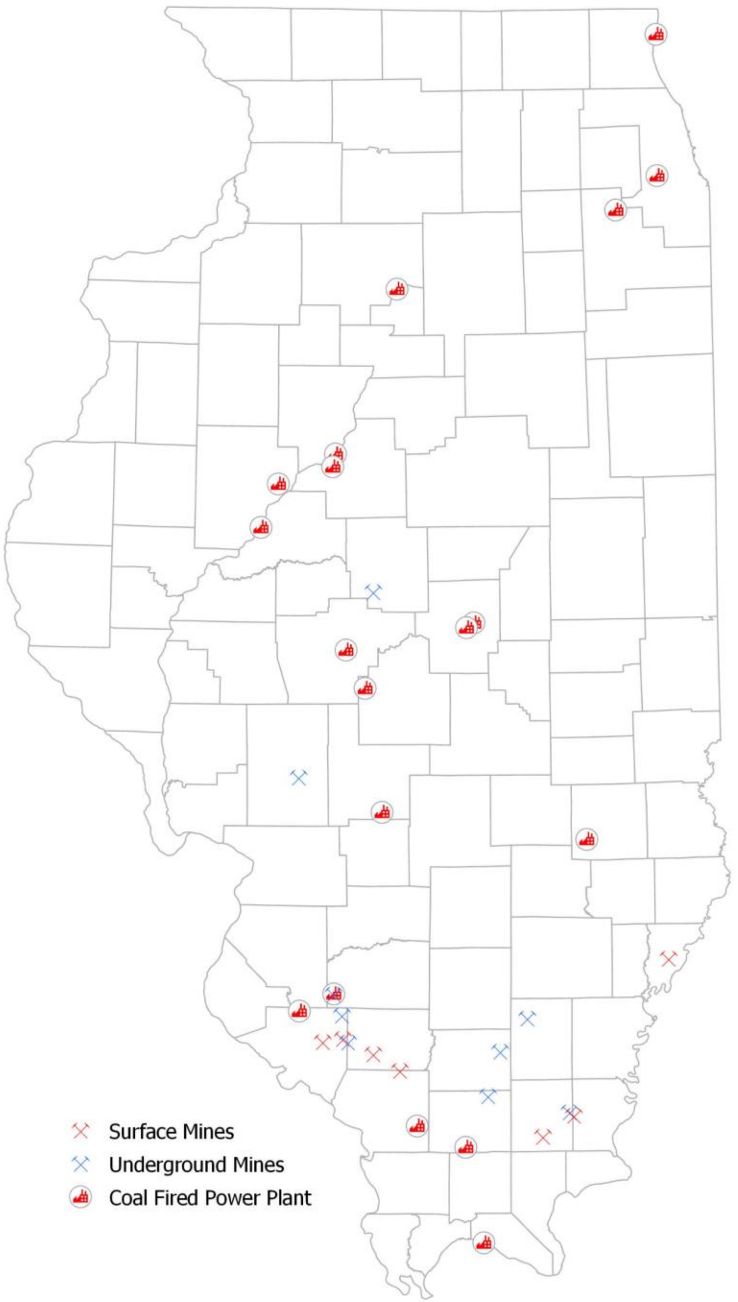
Major Industrial Plants

Major Coal-Fueled Industrial and Institutional Plants[1]

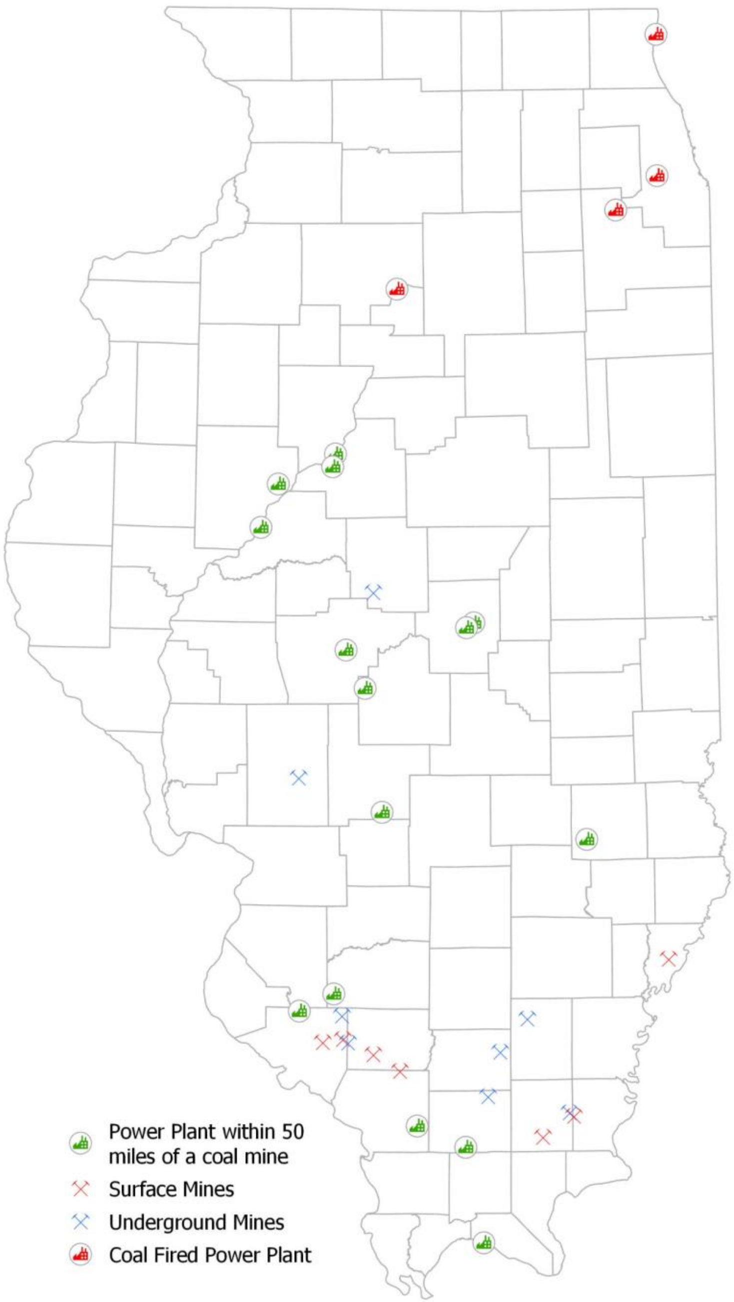
Company Map no., plant	County	Nameplate capacity CHP[2] (MW)	2016 coal purchased (1,000 tons)
Archer Daniels Midland			
1. Decatur	Macon	335	1,735
Ingredion Incorporated			
2. Ingredion Inc - Illinois	Cook	45	334
Southern Illinois University Carbondale			
3. SIUC Power Plant	Jackson	5.1	44
Tate & Lyle Decatur Plant Cogen			
4. Decatur	Macon	62	307

1 Source: U.S. Department of Energy, Energy Information Administration (EIA), 2016 Final EIA-923 Monthly Time Series File, EIA-923 and EIA-860.
2 CHP, Combined heat and power

Power Plants and Coal Mines



Power Plants within 50 Miles of an Illinois Coal Mine



Tom Benner
Office of Mines and Minerals
Illinois Department of Natural Resources
Phone: 217-782-7456
Email: tom.benner@Illinois.gov

FGD Task Force

Economic Considerations

Doug Brown, PE
Chief Utility Engineer

Agenda

- Market Conditions
- Barriers & Considerations
- New Technology

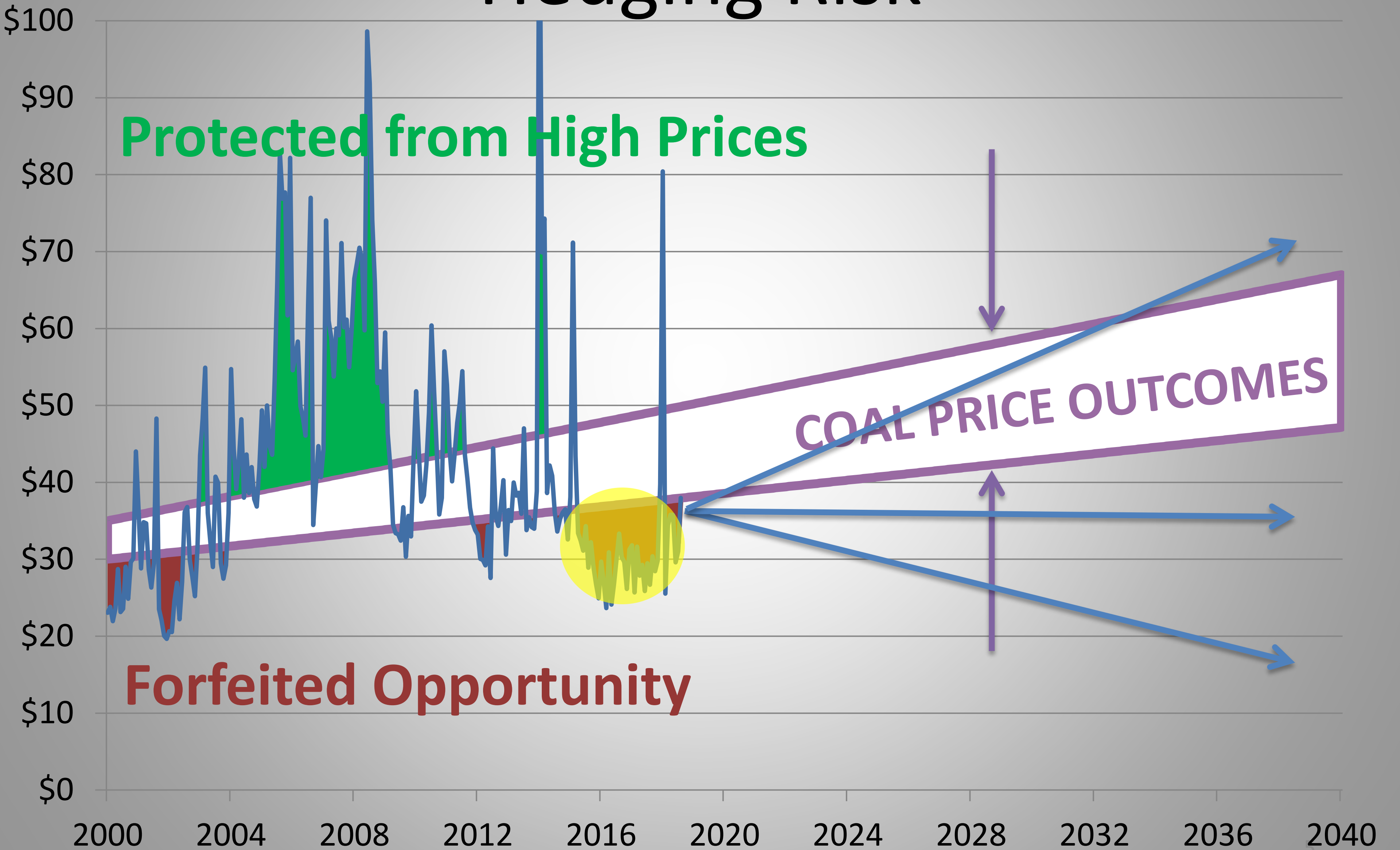
Market Conditions

- Unprecedented Load Decline
- Decreasing Costs of Gas, Wind & Solar
- Low Energy & Capacity Prices

Barriers & Considerations

- Reliability
- Risk
- Municipal Owned Generation
  - Alternative Investments (Transmission & Gen.)
  - Cost of Capacity, Energy and Ancillary Services

Hedging Risk



Barriers & Considerations

- Cost of Capital Improvements or Major Maintenance
- Environmental Compliance
  - Cost of capital improvements
  - Risk of non-compliance
  - Risk of future regulation
- Access to fuels (pipelines, coal, wind, solar)

New Technology

- Commercial Terms of an Agreement
  - Risk for Capacity Requirements
- Environmental & Reliability Compliance
  - Risk is born by Power Plants
  - Future Regulations
  - Permitting
- Benefit
  - Greatly reduce costs to Power Plants
  - No waste water
- Grants to Incentivize New Technology

THANK YOU

JET
JNG US

Ammonia Based Desulfurization

September 12th, 2018

Topics

- Company Profile
- Technology Overview
- Reference Projects
- Case Studies

JET Partnership

- Provide Additional Revenue Stream to Plant
- Reduce Plant's Operating Cost/Increase Capacity Factor
- Create Jobs and a needed byproduct (fertilizer)
- Reduce Plant's Emissions
- JET Invests Capital to Build Plant

JET's mission is to partner with plants to help achieve long term viability

Introduction to JET

JNEP (China Headquarters)

JET Global Headquarters (Ridgefield Park, NJ)

Global leader with 80% market share in Ammonia-Based Desulfurization

65 patents and patent applications (8 International)

150+ projects with more than 300 installed units

20+ installations with capacity bigger than 300 MW

Qualifications and Awards

- ☑ Grade A Design Qualification in Environmental Protection Projects
- ☑ Grade A Design Qualification in Chemical Engineering Projects
- ☑ Grade A Operation Qualification for Environmental faculties
- ☑ Contract Qualification for Environmental Projects
- ☑ Certificate of High and New Tech Enterprises
- ☑ ISO 9001 Quality Management System
- ☑ ISO14001 Environmental Management System
- ☑ OHSAS18001 Occupational Health and Safety Management System

20 Year History Ammonia Based FGD

	Year	Features	NH_3 recovery	SO_2 emission ppm	Total dust lb/MMSCF	Performance
1st Gen	1998	Basic NH_3 based deSOx	not controlled	~ 70		Meets SO_2 emission limit
2nd Gen	2010	NH_3 based deSOx with NH_3 recovery control	≥ 97%	< 35		Meets HG2001-2010 standard
3rd Gen	2013	Fine PM control	≥ 98%	< 17.5	≤ 4.72	Meets GB13223-2011 special emission limit
4th Gen	**2015**	**Ultrasound-enhanced deSOx and PM-removal integration**	**≥ 99%**	**< 12**	**≤ 1.18**	**Meets ultra-low emission limit***

Performance:

- SO_2 emission ≤ 12 ppm
- Particulate Matter Emissions ≤ 1.18 lb/MMSCF
- Ammonia Slip ≤ 3 ppm
- Ammonia Recovery Rate ≥ 99%

Over 300 units installed worldwide

Advantages of Ammonia Based FGD Technology

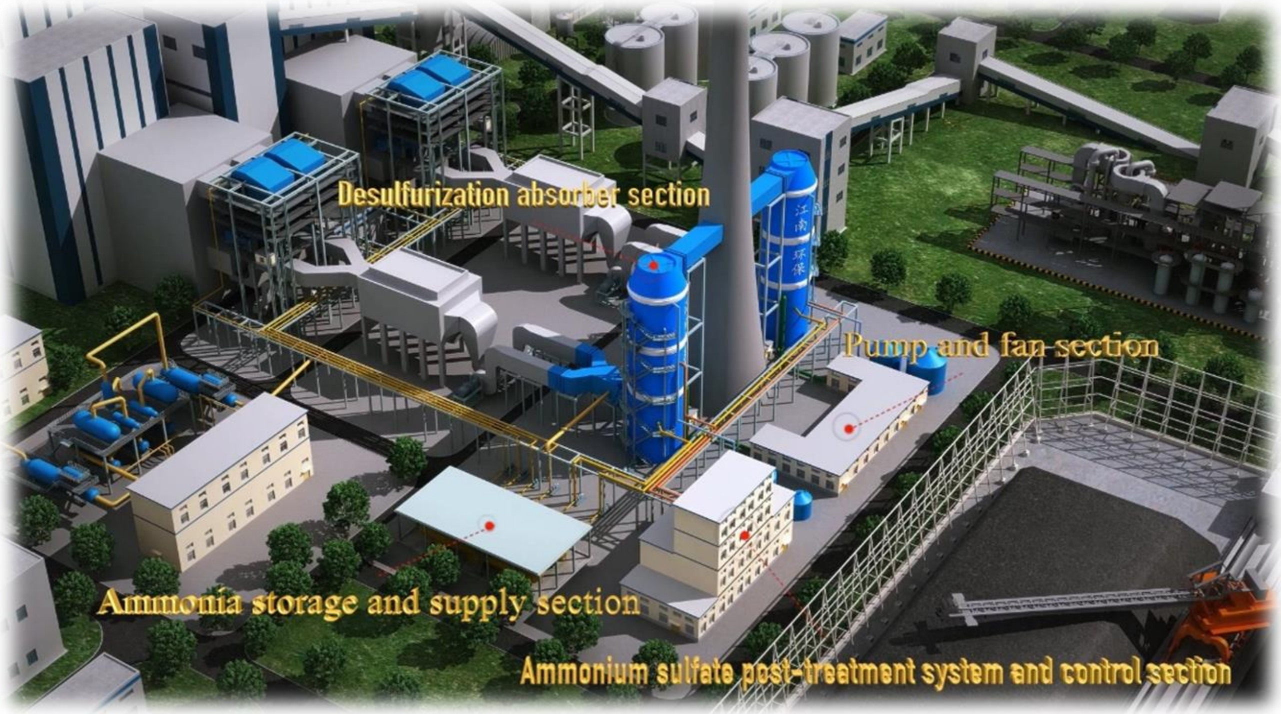
High SO_2 removal efficiency: 99% or higher

Environmentally friendly: no waste water, solid waste or additional CO_2 emissions

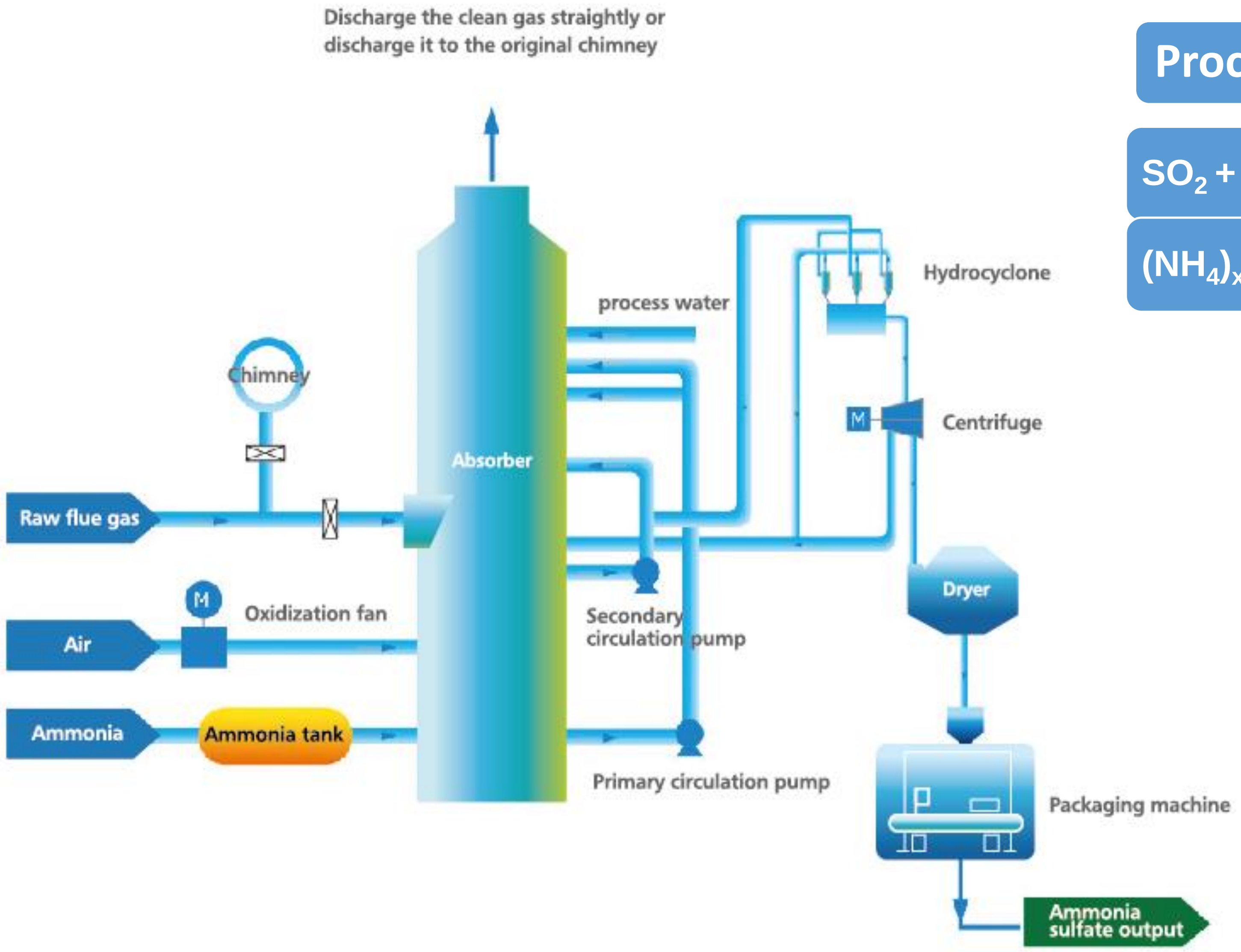
Extra profit: produce 3.8 ton fertilizer per 1 ton ammonia

High turndown ratio: 30%

Favorable economics: less power consumption & operating cost



Technology: Process Description



Process Mechanism

$SO_2 + H_2O + x\ NH_3 \rightarrow (NH_4)_xH_{2-x}SO_3$ (1)

$(NH_4)_xH_{2-x}SO_3 + \frac{1}{2}\ O_2 + (2-x)\ NH_3 \rightarrow (NH_4)_2SO_4$ (2)

Process Systems

- Flue gas system
- Absorption system
- Oxidation system
- Ammonium sulfate system

Technology: Desulfurization and PM Control

High Reactivity of NH_3

↓

High Absorption Efficiency

↓

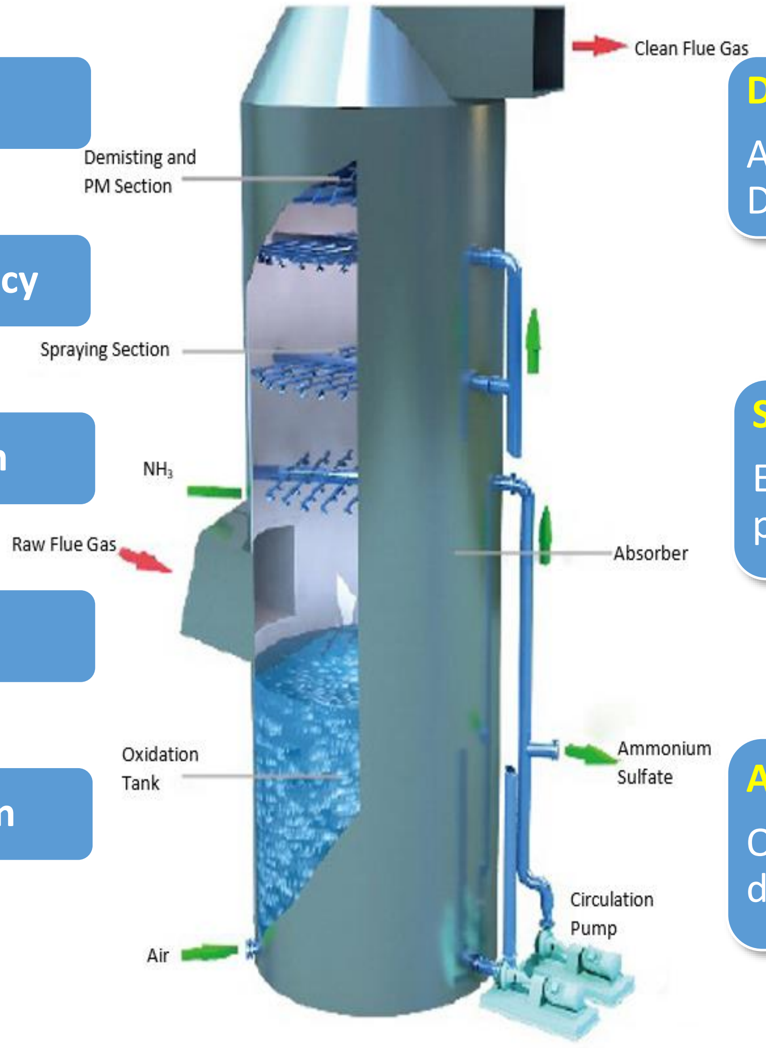
Low Liquid Recirculation

↓

Low System Pressure

↓

Low Power Consumption



Absorption:
Optimized spray, gas-liquid distribution, and oxidation control

↑

Scrubbing & Agglomeration:
Efficient scrubbing and cooling, fine particulate agglomeration (1-20 µm)

↑

Demisting:
Acoustic agglomeration (< 1 µm)
Demisting device design

Technology: Ammonium Sulfate System

Hydrocylone

Centrifuge

Dryer

Packaging Machine

Ammonium Sulfate Fertilizer

Oxidation blowers

Ammonia storage

Hydrocyclone

Centrifuge

Dryer

Ammonium Sulfate Product

Ammonium Sulfate Product

"Application of Ammonium Sulfate on diverse crops and growing demand for sulfur as a secondary nutrient are large drivers of the growth in North America. Growing use on specialty crops is a key driver of growth, and blending ammonium sulfate with other nutrients such as urea for additional nitrogen content has also increased."

-Green Markets Research Report

"As sulfur becomes more and more a factor in cropping systems, there continues to be a need to satisfy the demand with dry fertilizer formulations. The number one choice for sulfur in combination with nitrogen is ammonium sulfate and all interviewees believe this desirability based on economic utility will continue in the foreseeable future."

-Green Markets Research Report

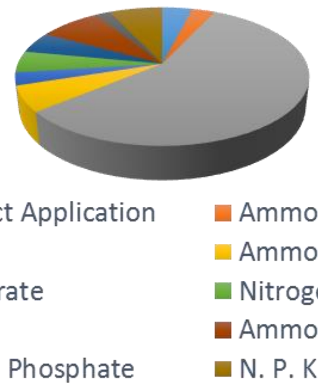
Fertilizer Outlook

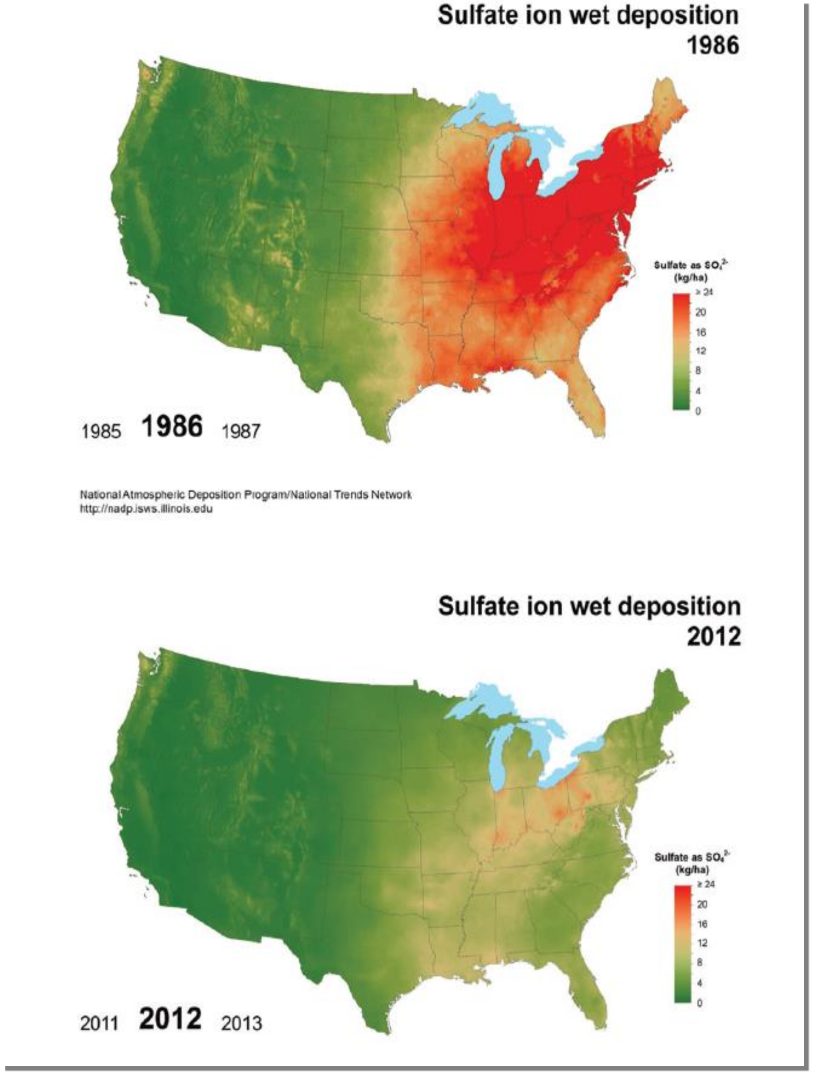
Global Demand of Nitrogen Base Fertilizer: 121.254 M Short Tons

Ammonium Sulfate 3% Market Share
- -Chemical Composition: 21% Nitrogen, 24% Sulfur
- -Price Point: $165/ston (Gulf NOLA)

Urea 56% Market Share
- - Chemical Composition: 46% Nitrogen
- -Price Point: $225/ston (Gulf NOLA)

Global Capacity of Nitrogen Fertilizer (%)





Some Reference Projects

No.	Client Name	Capacity	Contract date	Startup date
1	Sinopec Corp., Hubei Fertilizer Company	1×120MW+1×50MW	2006.08	2007.08
2	Nanjing YPC Refining & Chemical Co., Ltd.	2×150MW	2007.03	2008.03
3	Ningbo Jiufeng Power Co., Ltd.	1×125MW	2011.08	2012.06
4	Wanhua Chemical (Ningbo) Thermal Power Co., Ltd.	1×150MW+1×100MW	2012.05	2012.12
5	Sinopec Qilu Branch Thermal Power Plant	2×200MW	2011.09	2013.03
6	Inner Mongolia Datang International Keshiketeng Coal to Gas Co., Ltd.	160,000 t/year SRU	2010.04	2013.12
7	Yantai Wanhua Polyurethane Co., Ltd.	1×50MW+3×100MW	2012.09	2013.12
8	Lianyungang Hongyang Power Co., Ltd.	4×135MW	2012.01	2014.02
9	Ethylene Plant of Sinopec Qilu Petrochemical Co., Ltd.	2×100MW	2014.02	2015.08
10	Shenhua Ningxia Coal Group Co., Ltd.	10×200MW	2014.09	2015.12
11	Liaoyang Guocheng Power Co., Ltd.	3×150MW	2015.04	2016.01
12	Shandong Hualu Hengsheng Chemical Engineering Co., Ltd.	1×180MW+1×60MW+1×36MW	2016.05	2017.03
13	Xinjiang Meihua Amino Acid Co., Ltd.	2×450MW	2016.06	2017.06
14	Shenhua Ningxia Coal Group Co., Ltd. (Coal to Olefin)	6×150MW	2016.12	2017.06
15	Shaanxi Changqing Energy & Chemical Co., Ltd.	10,000 t/year SRU	2016.12	2017.6
16	Inner Mongolia Yitai Chemical Co., Ltd.	20,000 t/year SRU	2015.06	2017.09
17	Ningxia Ziguang Tianhua Methionine CO., Ltd.	10,000 t/year SRU	2016.10	2017.11
18	China National Offshore Oil Corporation Dongying Petroleum Co., Ltd.	10,000 t/year SRU	2016.10	under construction
19	Sinopec Corp. Jinling Branch	150,000 t/year SRU	2017.03	under construction
20	Sino-Kuwait joint-venture Refinery Integration Project in Guangdong	3×130,000 t/year SRU	2017.12	under construction

EADS Experience

Boiler/power plant flue gas desulfurization	**Sour/acid gas** treatment + **SRU tail gas** treatment	**FCCU** & **Sintering** machine flue gas desulfurization and PM control
• 150+ projects • 300 units • 40+ Ultra-low emission projects	• 15 projects	• 6 projects

Ningbo Jiufeng Power Co., Ltd.

Client Name	Ningbo Jiufeng Power Co., Ltd.
Location	Ningbo, Zhejiang
Capacity	Phase I： 3×130t/h boilers； Phase II： 1×130+1×410t/h boilers
EADS Generation	4th generation
Absorber Configuration	1# absorber is corresponding to boilers of Phase I 2# absorber is corresponding to boilers of Phase II
Stack Configuration	Steel stacks on top of the absorbers, 90 meters above ground
Absorbent	20% aqueous ammonia
Byproduct	1# and 2# absorbers share one set of ammonium sulfate treatment system, and the production capacity is 6.5t/h

Projects performed at Shenua Ningxia Coal Chemical Complex

Project/Plant	No. of Boilers	Capacity of Single Boiler	Boiler Type	No. of Absorbers	PM Control	NOx Control	EADS Generation
Coal to Methanol	4	240 t/h (60 MW)	CFB	4	Bag Filter	SNCR	4^{th} Gen
Coal to Propylene	6	460 t/h (150 MW)	PC	6	ESP	SCR	4^{th} Gen
Methanol to Propylene	4	280 t/h (70 MW)	CFB	4	Electric Bag Filter	SNCR	4^{th} Gen
Coal to Liquid	10	680 t/h (200 MW)	PC	10	ESP	SCR	4^{th} Gen

World's largest Ammonia FGD Project

Client Name	Shenhua Ningxia Coal Industry Group CTL Project
Location	Yinchuan, Ningxia Province, China
Capacity	10×200 MW units
EADS Generation	Currently 3rd generation, being upgraded to the 4th generation
Absorber Configuration	1 absorber for 1 unit, total 10 absorbers Absorber diameter: 10.5m, Height: 45m
Stack Configuration	Two concrete stacks with metal liner
Absorbent	99.6% anhydrous ammonia, consumption: 8.5 t/h (maximum capacity load)
Byproduct	Ammonium sulfate in bags, production: 42.9t/h (maximum capacity load)

Test Report of #5 FGD Project at Wanhua Power Co., Ltd.

Project Background Information

- **Location**
  - Ningbo, China
- **EADS Generation**
  - 4th Generation
- **Capacity**
  - 100 MW
- **Flue Gas Flow**
  - 314,078 SCFM
- **Inlet SO2 Concentration**
  - 1,040 ppm

FGD Performance

- **Outlet SO2 Concentration**
  - 1.76 ppm
- **Outlet PM Concentration**
  - 0.27 lb/MMSCF
- **Ammonia Slip**
  - 0.33 ppm

Economics

S.N.	Item	Spec	Unit	Hourly consumption	Annual operating hours	Annual consumption
1	Anhydrous Ammonia	99.6%	ton	17.37	6,300	109,444
2	Process water		ton	381.39	6,300	2,402,778
3	Power	13kV/480V	kWh	13,948.00	6,300	87,872,400
4	Steam	120 psi	ton	30.74	6,300	193,681
5	Instrumental air	100 psi	1,000 SCF	7.60	6,300	47,880
6	Cooling water	50 psi	ton	220.00	6,300	1,386,000
7	Packaging bags	100 lb	ea	1,331.35	6,300	8,387,500

Economics

S.N.	Item	Spec	Unit	Unit price (USD)	Annual consumption	Annual cost(USD)
1	Anhydrous ammonia	99.6%	ton	450	109,444	49,250,000
2	Process water	0.0%	ton	0.40	2,402,778	961,000
3	Power	13kV/480V	kWh	0.025	87,872,400	2,197,000
4	Steam	120 psi	ton	8	193,681	1,549,000
5	Instrumental air	100 psi	1,000 SCF	0.60	47,880	29,000
6	Cooling water	50 psi	ton	0.02	1,386,000	28,000
7	Packaging bags	100 lb		0.40	8,387,500	3,355,000
8	Labor		$			1,760,000
9	Maintenance		$			1,650,000
10	Total cost					60,779,000
11	Sales of ammonium sulfate		ton	200	419,362	83,872,000
12	Annual SO_2 removed		ton		201,118	
13	**Total operation cost**					**-23,093,000**

Applicability to US Power Plants

Why Ammonia FGD is a Better Choice than Limestone Process?

	Limestone Process	EADS Process
Absorbent	Limestone	Ammonia
By-Product	Gypsum	Ammonium Sulfate Fertilizer
SO_2 Removal Efficiency	≥ 95%	≥ 99%
Waster Water	55 lb/ hr/ MW	None
CO_2 Emissions	0.7 t/ t SO_2 Removed	None
Power Consumption	Base	35-50% Less than Base
Operating Cost	Base	None

Side by Side Comparison

Case Study

Design Specifications

Capacity: 2×660 MW	
Flue gas flow: 2×1,550,000 SCFM	
SO_2 content in flue gas: 3,075 PPM	

FGD Performance

SO_2 removal efficiency ≥ 99.5%	
SO_2 emission ≤ 12 PPM	
PM emission ≤ 0.29 lb/MMSCF	

OPERATING COST COMPARISON, $/YEAR		
ITEM	ANNUAL COST (USD)	
	EADS	LIMESTONE PROCESS
Ammonia (99.6%)	55,231,000	
Limestone		14,537,000
Process Water	901,000	1,027,000
Power	3,457,000	5,712,000
Steam	1,298,000	
Labor	1,760,000	1,760,000
Packaging Bags	2,116,000	
Maintenance Cost	2,200,000	2,200,000
Wastewater Disposal		4,284,000
Cooling Water	31,000	31,000
Instrumental Air	32,000	32,000
By-product		
Ammonium Sulfate	-105,814,000	
Gypsum		2,864,000
Total	-38,788,000	32,447,000

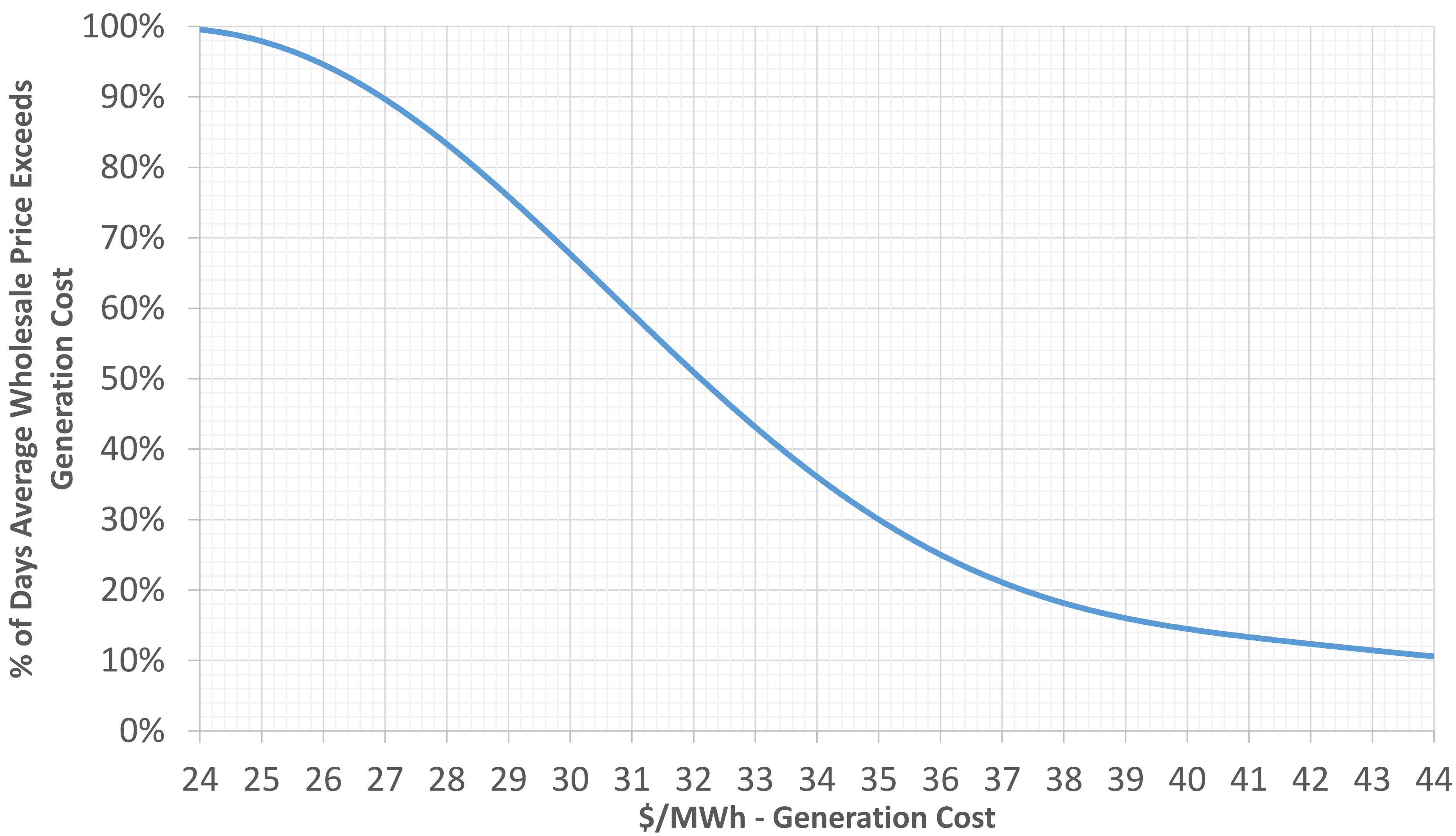
Case Study 2

- Plant burning high sulfur coal (~3% Sulfur)
- ~2600 MW
- ~50% Capacity Factor
- Plant receives:
  - Operating cost reduction of **$55,525,000 ($3.99/MWh)***
    *excludes waste water cost reduction

Generation in 2016 (MWh)	13,924,000
Operation Cost Savings from JET's Solution	**$55,525,000**
Cost savings in dollars per MWh	**$3.99**

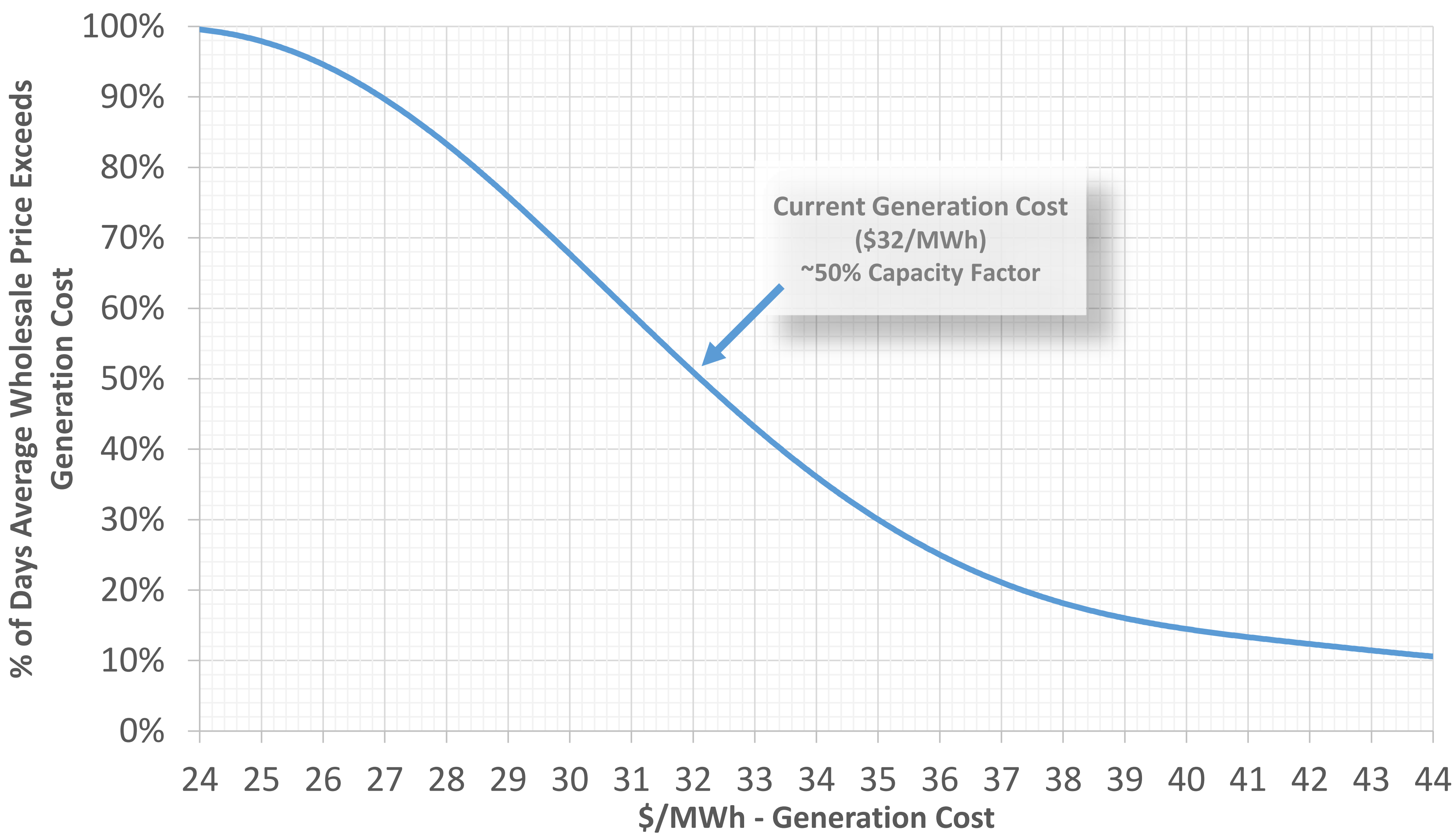
Total long term positive impact of $55,525,000 ($3.99/MWh)

Operational Cost Impact on Plant Capacity Factor



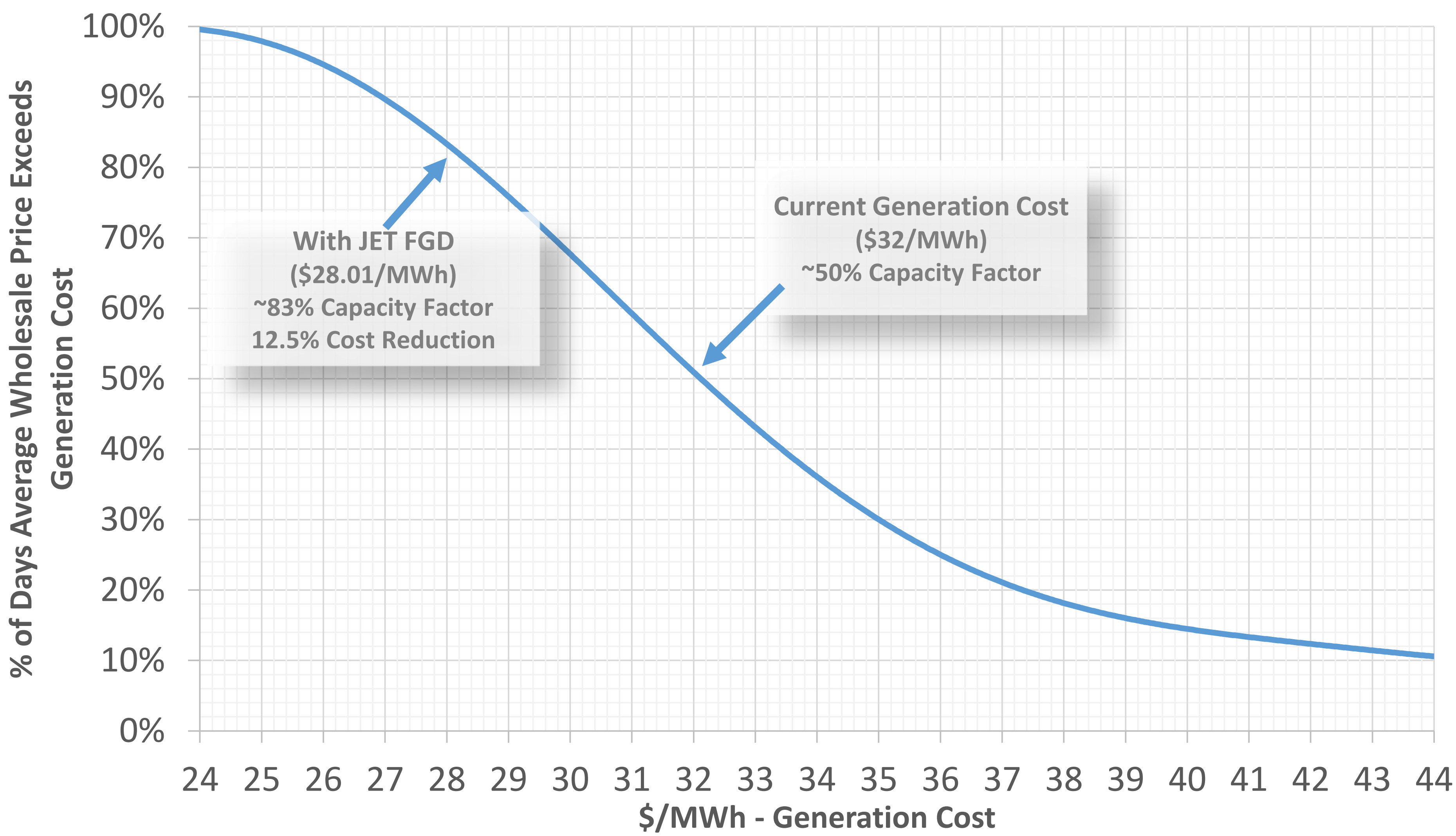
Source: EIA 2017 Wholesale Energy Prices in PJM Western Hub

Operational Cost Impact on Plant Capacity Factor



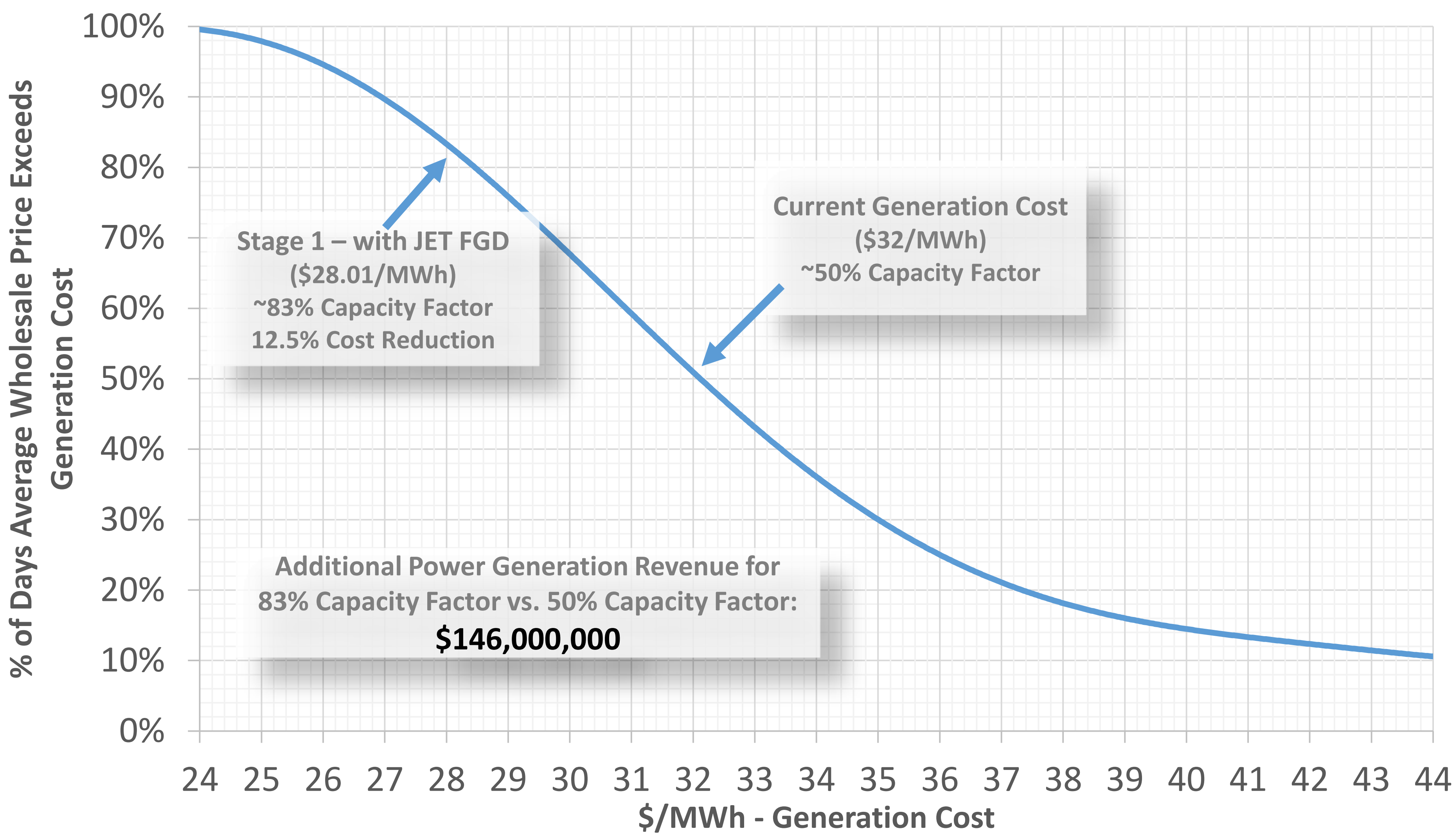
Source: EIA 2017 Wholesale Energy Prices in PJM Western Hub

Operational Cost Impact on Plant Capacity Factor



Source: EIA 2017 Wholesale Energy Prices in PJM Western Hub

Operational Cost Impact on Plant Capacity Factor



Source: EIA 2017 Wholesale Energy Prices in PJM Western Hub

Conclusions

- Ammonia Desulfurization is a mature, viable technology
- EADS offers significant potential for US Coal Plants as a replacement for existing sulfur removal strategy

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III. Public Comments to the FGD Task Force

1. **Public Comments of Peabody**
2. **Public Comments of JET**
3. **Public Comments of Vistra**
4. **Technical Evaluation of an Ammonia-Based SO_2 Scrubbing Technology's Potential Applicability to Vectren's A.B. Brown Generating Station – Submitted by JET**

Peabody

Peabody
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November 12, 2018

Alec Messina
Director
Illinois Environmental Protection Agency
1021 North Grand Ave. East
P.O. Box 19276
Springfield, IL 62794

Dear Mr. Messina:

I am writing to provide comments on a recent draft of the Flue Gas Desulfurization (FGD) Task Force Report entitled, "Analysis of the Illinois Coal Industry and Electrical Generation in Illinois."

As you know, Peabody operates multiple underground mines and surface operations across the United States and holds leadership positions in production and reserves in the Illinois Basin (ILB). In 2016, our ILB operations located in Illinois and Indiana sold 18.3 million tons of coal, employed 1,550 workers, restored over 2,500 acres of coal mined lands and injected $1.5 billion in direct and indirect economic benefits to the region. In total, Peabody has approximately 400 million tons of proven and probable reserves in the ILB.

In Illinois specifically, wholly owned subsidiaries of Peabody operate three coal mines: Gateway North, Cottage Grove and Wildcat Hills Underground. In 2016, these operations sold 3.7 million tons of coal, employed approximately 400 individuals and injected over $275 million in direct and indirect economic benefits to the state and local communities. Our company also supplied 15.7 million tons of coal to electric generating facilities in Illinois from our Wyoming operations located in the Powder River Basin.

As the largest coal reserve holder in the ILB and the largest supplier of coal to Illinois electric generators, Peabody brings a unique viewpoint to the FGD Task Force. Our U.S. business unit has been able to successfully operate coal mines in both the PRB and ILB basins. Given our companies expertise in both markets, I would like to comment on the following statements included in the draft report:

1. *The FGD Task Force Act (20 ILCS 5120; Section (10)(a)) was created to "increase the amount of Illinois Basin coal use in generation units" and "identify and evaluate the costs, benefits, and barriers of new and modified FGD...while improving the ability of those generation units to meet...ELGs for wastewater discharges...and enhancing the marketability of the generation units' FGD byproducts."* (Page 1)

The report focuses heavily on Illinois electric generating units despite the FGD Task Force Act not specifically mentioning Illinois Basin coal use in Illinois generating units, but rather "Illinois Basin coal use in generating units." The Act does not limit this report to generating units in Illinois, yet the draft report has done this. There are several generating units consuming Illinois Basin coal outside of the state of Illinois and the continued consumption by these generating units would greatly benefit the state of Illinois. In other words, the report does not fulfill the requirements of the Act since it does not consider all Illinois Basin coal and only limits its purpose to "Illinois coal use in Illinois electrical generation." (Page 1)

The report, as outlined in the Act, fails to take into consideration ways to benefit all Illinois Basin coal (located in Illinois, Indiana and Western Kentucky) as well as consider ways to promote *all* generation units that utilizes Illinois coal. As noted in a presentation by the Office of Mines and Minerals, 29.9 tons of Illinois coal was exported out of state in 2016. The report should also consider ways to equally promote Illinois coal consumption at out-of-state generating units as well – as instructed by the Act.

As an example, the Gateway North Mine located in Randolph County provides coal to Indiana's Schahfer coal generating units. The report should "identify ways to evaluate the costs, benefits, and barriers of new and modified FGD...while improving the ability of those generation units to meet...ELGs for wastewater discharges...and enhancing the marketability of the generation units' FGD byproducts" *(20 ILCS 5120; Section (10)(a))* at this facility. By doing so, it could help prevent closure of the power plant while at the same time preserve coal jobs in Illinois potentially without increasing delivered coal costs or SO2 emissions for Illinois generating units and Illinois consumers.

2. *While some Illinois power generators did install pollution control equipment to allow them to continue to burn Illinois coal, the majority of the coal-fired generation in the state chose to fuel switch their fuel source to low-sulfur coal.* (Page 2)

This statement notes that much of the fuel currently consumed in the state utilizes low-sulfur coal, however it implies that this was the only action taken by Illinois power generators. The chart below uses data from the draft report's Table 1 (Page 6) to demonstrate that the majority of Illinois power generators choose to *both* utilize low-sulfur coal *and* SO2 controls. Below you can see that almost 7000 MW of Illinois generation utilizes both low-sulfur coal and SO2 control equipment, while 4500 MW opted to utilize only low-sulfur coal, and 2500 MW chose to utilize ILB coal and SO2 control equipment. This demonstrates that even with SO2 controls in place, a majority of Illinois power generators continue to utilize low-sulfur coal.

Low-Sulfur Coal and SO2 Control		Low Sulfur Coal Only		ILB Coal and SO2 Control	
Plant	Capacity (MW)	Plant	Capacity (MW)	Plant	Capacity (MW)
Baldwin	2,032	Hennepin	326	CWLP	567
Havana	493	ED Edwards	728	Prairie State	1,664
Coffeen	984	Joppa Steam	1,364	SIPC Marion	312
Duck Creek	484	Newton	748		
Kincaid	1,297	Waukegan	756		
Powerton	1,673	Will County	534		
Total MW	6,963	Total MW	4,456	Total MW	2,543
Units	13	Units	14	Units	8

3. *Since the mid-1990s, over 50 million tons per year of coal from Western states have been transported to be burned in Illinois power plants.* (Page 2)

Per the presentation provided by the Office of Mines and Minerals, only 30.6 million tons of coal from western states were transported to Illinois power plants in 2016. The report should note the decline in western coal consumption as well. See Figure 1 on Page 4 of the draft report.

In addition, the report should acknowledge the realities around coal trade and note Illinois coal is consumed in several coal producing states as well, including Alabama (1.4 million), Tennessee (2.4 million), Indiana (3.2 million), Kentucky (4.0 million) and Ohio (3.6 million) for a total of 14.6 million tons. This is significant because it demonstrates it is common for coal produced in one state to be competitive in other states, even if that state has its own coal production. Further, under the draft report's considerations, it should note that if Illinois takes action to promote consumption of Illinois coal at Illinois generating units, other states could take similar actions thereby placing almost 15 million tons of Illinois coal exports at risk.

4. *A key factor in this decision was an order from the ICC which approved transportation costs as part of the fuel costs meaning these costs were immediately recoverable in electric sales through the Fuel Adjustment Clause.* (Page 2)

This is common practice in electricity markets across the U.S. and it is not unique to Illinois. In addition, the cost of most products sold to consumers in Illinois will include the transportation costs. The report should note this fact and place less emphasis on the order from the ICC as a major factor, but rather focus on the fact that it would likely be a violation of the Interstate Commerce Clause for Illinois to prevent utilities from recouping transportation costs. Imagine the economic impact on the state of Illinois if the transportation costs associated with its top export products, like soy beans, light petroleum products, off-highway equipment, etc. were not recoverable in the sales to customers out of state.

Further, had the ICC not made this decision, the cost of electricity in the state would likely have increased since Illinois power generators would be forced to consume more expensive coal and generating units would require emission controls and higher operating costs.

5. *Table 1 entitled, "List of Coal-Fired Electrical Generation in Illinois" lists various Illinois generating plants, total capacity, control equipment and coal source.* (Page 6)

This Table provides useful information in understanding the current markets and emission control schemes for coal utilization in the state of Illinois. It should be noted, that even though plants like Baldwin, Havana, Coffeen, Duck Creek, Kincaid and Powerton utilize various forms of SO2 control equipment, they still use PRB coal as its coal source over ILB coal. This is primarily due to the lower delivered costs of PRB coal. It is important to note this because even if a generating unit adds SO2 emission control equipment, PRB coal delivered costs are still lower than ILB delivered costs – as noted in the chart above. So, these power plants not only have a lower delivered coal cost, but they also have lower SO2 emissions because they utilize both low-sulfur coal and SO2 emission controls.

A consideration the Task Force needs to take in to account is whether or not the utilization of Illinois coal will increase the SO2 emissions in the state, potentially creating a violation of the NAAQS and placing an area into nonattainment causing negative economic impacts.

Through our annual Peabody Clean Coal Awards, we seek to honor quality work to advance high-efficiency, low-emissions generation and low-carbon systems. In 2016, Dynegy's Coffeen Plant was given the award for "Best SO2 Emissions Rate among U.S. Coal Plants." The power plant operates in central Illinois and has a SO2 emissions profile that is 99 percent better than the U.S. coal fleet average. This plant was able to demonstrate the lowest SO2 emissions in the nation precisely because it utilizes a combination of both low-sulfur coal *and* a wet limestone scrubber.

6. *"...the high sulfur content of Illinois coal remains the primary barrier to its use in power generation in Illinois and elsewhere."* (Page 7)

While this statement notes the primary barrier accurately, this section should be cautious not to mislead the reader into believing that if this barrier is removed it will create a boon for the Illinois coal industry. While not the primary barrier, there are still prohibitive barriers for Illinois coal to be utilized in power generation in Illinois and elsewhere as evidenced by the generation units that have wet SO2 control equipment, and thus have the ability to use ILB coal, but choose to use PRB coal.

7. *Control of SO2 emissions to limit formation of PM2.5 is a key goal of the Regional Haze Rule.* (Page 7)

It should be noted that in Louisiana's most recent State Implementation Plan for compliance with the Regional Haze rule, the state labeled low-sulfur coal as the Best Available Control Technology for compliance with the rule. The EPA approved this SIP. In addition, other states, like Arkansas, are following suit and labeling low-sulfur coal as a 'control technology' to comply with Regional Haze requirements in SIPs.

8. *"Illinois coal and delivered PRB coal are roughly equal in terms of cost in dollars per ton." (Page 10)*

The draft report compares the spot price (at the mine) for Illinois coal with the delivered price of PRB coal and this is not a fair comparison. In order to provide an accurate comparison, the delivered cost should be used for both. Based on FERC data, the average 2017 *delivered* cost for PRB coal and IL coal in Illinois was $31-$32 and $36-$38, respectively. A ton of delivered IL coal is significantly costlier than a ton of delivered PRB coal, about $5.50 more per ton. A good example of this is the Prairie State Energy Campus which utilizes ILB coal at a mine mouth coal generating facility in Marion, IL – meaning the mine in adjacent to the power plant and feeds the coal directly to plant without transportation. Its coal costs were approximately $32 in 2017. More detailed information is provided in the chart below, and this publicly available data suggests the statement in the draft report is misleading.

Holding Customer	Unit Name	State	Capacity (MW)	Total Plant Primary Coal Basin 2017	2017 Fuel Delivered Coal Cost ($/t)
Dynegy	Baldwin ST 1	IL	1,185	SPRB	$32.14
Dynegy	Coffeen ST 1	IL	915	SPRB	$32.29
Dynegy	Duck Creek ST 1	IL	425	SPRB	$33.05
Dynegy	E D Edwards ST 2	IL	585	SPRB	$32.62
Dynegy	Havana ST 6	IL	434	SPRB	$32.80
Dynegy	Hennepin ST 2	IL	226	SPRB	$32.79
Dynegy	Newton ST 1	IL	615	SPRB	$32.29
Dynegy	Kincaid ST 1	IL	1,158	SPRB	$32.44
Dynegy	Joppa Steam ST 1	IL	1,002	SPRB	$32.02
NRG	Powerton ST 5	IL	1,538	SPRB	$31.82
NRG	Waukegan ST 7	IL	689	SPRB	$32.06
NRG	Will County ST 4	IL	520	SPRB	$31.83
				PRB	**$ 32.29**
	Marion CFB 1	IL	290	ILB	$36.42
	Dallman ST 1	IL	534	ILB	$38.70
				ILB	**$ 37.76**

9. *"The major factor in the use of PRB coal rather than Illinois coal is the sulfur content of each fuel." (Page 10)*

While the sulfur content is a major factor, it should be noted that there are additional factors in the use of PRB coal rather than Illinois coal, including higher chlorine content, different ash handling storage requirements and potential boiler design changes needed with Illinois coal being utilized in Illinois generating units.

10. *These limits apply to all of the units listed in Table 1 that are currently operated by Vistra and Midwest Generation, and also account for all of the facilities on that list burning PRB coal.* (Page 10)

The MPS and CPS limits are not the only reason that account for the facilities listed in Table 1 utilizing PRB coal. As previously noted, the delivered price of PRB coal is about $5.50 per ton less than the delivered price of ILB coal making it lower cost, in addition, ILB coal has higher chlorine content, different ash handling storage requirements and potential boiler design changes may be needed with utilizing Illinois Basin coal.

11. *Section on Comparison of Illinois Coal and PRB Coal* (Page 10)

This section should note the stark differences between the two coal basins and suggest adding the following: "The PRB's growth is attributed to several factors: low sulfur composition of the coal, lower production costs due to the coal's proximity to the surface, and recoverable coal seams that can be as much as 80-100 feet thick. ILB coal seams typically range between 4-8 feet thick."

In addition, adding "In 2016 coal produced in the PRB was sold in well over 25 states across the U.S. and 10 of those states have their own coal production. Illinois coal was sold to about a dozen different states and four of those states have their own coal production. As this suggests, it is extremely common for coal from one state to compete with coal from another state, as it is with most commodities."

12. *"Wet scrubbing system capital costs range from $50 to $125 million, and annualized costs range from $10 to $25 million annually." (Page 12)*

While the capital costs associated with emission control technologies like a scrubbing system are difficult to estimate and will differ between various electric generating units and the technology selected, the cost estimate used in the draft is much lower than what is presented on the U.S. EPA website.[1] In fact, the ranges provided appear to be similar in nature for a single unit, not for an entire generating plant and clarity needs to be provided on these estimates at a minimum.

Thank you for this opportunity to provide comments on the draft report produced by the FGD Task Force. Peabody's legacy in Illinois dates back to 1883 when our founder, Francis S. Peabody, established a coal, wood and coke business in Chicago to supply coal for heating nearby homes. With deep roots in Illinois, we have a keen interest in the state's future energy

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[1] US Environmental Protection Agency, Air Pollution Control Fact Sheet, https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf

policy and seek to remain engaged in efforts to increase ILB coal use in generating units, and we look forward to continuing to work with the FGD Task Force.

Sincerely,

Michael Blank
Director State Government Relations
Peabody

CC:
Illinois Senator Dale Fowler
Illinois Senator Andrew Manar
Illinois Senator Paul Schimpf
Illinois Representative Avery Bourne
Illinois Representative Linda Chapa LaVia
Illinois Representative Anna Moeller
Illinois Representative Dave Severin
Doug Brown, City Water, Light & Power
Bill Matuscak, Archer Daniels Midland
Phil Gonet, Illinois Coal Association

November 16, 2018

Alec Messina
Director
Illinois Environmental Protection Agency
1021 North Grand Ave. East
PO Box 19276
Springfield, IL 62794

Dear Mr. Messina:

Jiangnan Environmental Technology Inc. (JET Inc.) is providing comments to the draft report from the Flue Gas Desulfurization Task Force, "Analysis of the Illinois Coal Industry and Electrical Generation in Illinois." The FGD Task Force Act (20 ILCS 5120; Section (10(a)) was created to "increase the amount of Illinois Basin coal use in generation units" and "identify and evaluate the costs, benefits, and barriers of new and modified FGD…while improving the ability of those generation units to meet…ELGs for wastewater discharges…and enhancing the marketability of the generation units FGD byproducts". Our company's mission is closely aligned with this directive. Our mission is to keep coal fired assets operational, lower the overall emissions, maintain employment, and provide the ability to operate these facilities at an economic advantage by eliminating the cost of sulfur dioxide removal and generating a profit from the sale of a valuable byproduct.

Our Comments are:

1. We were graciously invited to present our technology to the Task Force, and we feel it is important for the Task Force to provide sufficient detail and discussion regarding our technology and proposal to help the Electrical Generation Units. On Page 1 of the draft FGD Task Force report, it states that "The purpose of this document is to provide the background and analysis necessary for policy makers to arrive at informed decisions regarding Illinois coal use in Illinois electrical generation." One General comment about the report is that there is a need to provide additional information regarding the Ammonia Based Scrubbing technology that is introduced in the draft report so that stakeholders can make the most informed decision possible. A third party, independent evaluation of Ammonia Based Desulfurization was performed and submitted in Testimony for Vectren's AB Brown Generating Station's Cause 45052. The evaluation is submitted alongside these comments to provide the additional information necessary to make informed decisions.

   The title of the report is "Technical Evaluation of an Ammonia-Based SO_2 Scrubbing Technology's Potential Applicability to Vectren's A.B. Brown Generating Station."

   <u>Summary of the Report:</u>

   Trimeric investigated the alternative of retrofitting Vectren's A.B. Brown coal-fired generating units with an ammonia-based SO2 scrubber technology that could eliminate or materially reduce the wastewater discharge from the scrubbing process and produce commercially saleable agricultural fertilizer as a byproduct of the process. For this investigation, Trimeric gathered information about A.B. Brown Station and about ammonia-based scrubbing technology, reviewed publicly available data, and held several conversations with engineers from Marsulex Environmental Technologies (MET) and Jiangnan Environmental Technology (JET). Trimeric also visited three operating coal-fired plants with ammonia-based SO2 scrubbing technology installed and operating.

Trimeric found that ammonia-based scrubbing is a commercially-available technology that can achieve high levels of SO_2 removal. The technology can produce a saleable fertilizer byproduct. If implemented, an ammonia-based scrubber could eliminate the concern that Vectren has about complying with U.S. Steam Electric Power Generating Effluent Limitations Guidelines (ELG) regulation. The technology has been successfully deployed in Poland and China at coal-fired power plants at a scale comparable to the A.B. Brown units and using similar equipment design to what would be used at A.B. Brown. Other technical aspects of the ammonia-based scrubber were evaluated, including process availability/reliability/maintenance, ammonia and ammonium sulfate handling safety, effect on the generating plant's water balance and byproducts, impact on ability to install carbon capture technologies, effect on other air emissions, and a preliminary economic analysis. With respect to these aspects, no adverse information was identified in Trimeric's investigation that would be likely to prevent the ammonia-based scrubbing technology from being a potentially viable candidate for an SO_2 removal technology for A.B. Brown. As to mercury emissions and particulate matter emissions, further investigation would be required to determine if additional mercury removal processes and/or particulate control technologies, both of which are commercially available, would need to be deployed along with an ammonia-based scrubber at A.B. Brown to meet current emissions limits.

Reason for inclusion in the Task Force Report:

The Task Force did not have the resources needed to evaluate in detail, the technical and environmental analysis of Ammonia based desulfurization as it relates to a coal fired power plant in Illinois. Trimeric did perform this analysis, and the report will provide stakeholders access to this information. The power plant that the analysis was performed for (AB Brown Generating Station) is representative of some of the power plants in Illinois that the FGD Task Force is focused on.

2. Additionally, to provide further clarity, we wanted to present a case study into the Task Force Report. We used Kincaid for this example but can provide additional case studies for any of the other coal plant in Illinois. All the generation and FGD cost data came from Form EIA-923. The Form EIA-923 collects detailed electric power data -- monthly and annually -- on electricity generation, fuel consumption, fossil fuel stocks, and receipts at the power plant and prime mover level. The analysis is as follows. First, the data regarding the existing power generation, coal consumption and SO_2 removal costs are provided. Next, the economics of the ammonia based desulfurization unit is presented. Finally, the additional cost savings and overall economics of the system are presented.

Existing Power Generation, Coal Consumption, and SO2 removal costs at Kincaid

In 2017, Kincaid generated 4,666,728 MW hours of electricity from a total coal consumption of 50,418,601 MMBtu. The plant burned low sulfur Powder River Basin coal, and removed the sulfur dioxide from the flue gas utilizing dry sorbent injection. EIA provides the sulfur removal costs in 2017 as $9,778,000.

Table 1. Kincaid Operating Values and SO2 removal costs in 2017

Parameter	Values – 2017
Electricity Generation	4,666,728 MWh
Total Coal Consumption	50,418,601 MMBtu
Sulfur Removal Costs	**$9,778,000**

Economics of Ammonia Based Desulfurization

Installing JET's technology at the site will allow for the following economics for the Sulfur Removal, assuming a fuel switch to high sulfur bituminous coal, like the coal found in the state of Illinois. This analysis uses the same Electrical Generation and coal consumption, with a 3% Sulfur (~6 lb Sulfur/MMbtu) coal:

Table 2. Ammonia Based Desulfurization Economics at Kincaid, based on 2017 operating parameters

Parameter	Value
Cost to Operate, including Ammonia cost	$29,830,000
Revenue gained from Ammonia Sulfate Sales	$53,475,000
Yearly Profit	**$23,644,000**

Economics of Switch to Illinois Basin Coal

Finally, when the fuel switch to high sulfur coal is performed, the fuel cost for the facility will be decreased. From the numbers provided using FERC data, an 11,800 btu/lb coal from the Illinois basin will cost approximately $38/ton (or $1.61/MMBtu) delivered to Kincaid and an 8,800 btu/lb coal from the Powder River Basin will cost $32/ton (or $1.82/MMBtu) delivered to Kincaid. For the 50,418,601 MMBtu of coal consumed at Kincaid at 2017, the cost of PRB fuel would be $91,762,000 and the cost of the Illinois Basin Fuel would be $81,174,000, leading to an additional savings of $10,588,000 annually.

Table 3. Economics of Fuel Switch at Kincaid, based on FERC data

Parameter	Value
Cost of existing PRB Fuel	$91,762,000
Cost of Illinois Basing Fuel	$81,174,000
Yearly Savings from coal switch	**$10,588,000**

Overall Economics

Therefore, with the switch to ammonia based desulfurization, Kincaid can burn Illinois Basin Coal and in the process realize an annual positive economic impact of **$44,010,000.**

Table 4. Total Positive Annual Economic Impact, Kincaid

Parameter	Value
Elimination of existing SO2 Removal cost	$9,778,000
Profit from Ammonia FGD	$23,644,000
Yearly Savings from coal switch	$10,588,000
Total Savings	**$44,010,000**

Thank you for the opportunity to submit these comments on the draft FGD Task Force Report. JET strongly feels that with the utilization of our technology, the Task Force has a real opportunity to do something meaningful that allows increased use of Illinois Basin Coal. Our missions are aligned, and we are looking forward to continuing to work with the Task Force.

Sincerely

David Repp

David Repp
Director, Business Development
JET-Inc.

CC:
Illinois Senator Dale Fowler
Illinois Senator Andrew Manar
Illinois Senator Paul Schimpf
Illinois Representative Avery Bourne
Illinois Representative Linda Chapa LaVia
Illinois Representative Anna Moeller
Illinois Representative Dave Severin
Doug Brown, City Water, Light & Power
Bill Matuscak, Archer Daniels Midland
Phil Gonet, Illinois Coal Association

Attachments:

"Technical Evaluation of an Ammonia-Based SO2 Scrubbing Technology's Potential Applicability to Vectren's A.B. Brown Generating Station."

Vistra Comments to the FGD Task Force

Vistra and IL Coal

As the owner of 9 coal-fired power plants in Illinois and owner of 5 additional coal-fired power plants in Ohio and Texas, Luminant, a subsidiary of Vistra, is continuously evaluating fuel supply options with the goal of finding the best mix of coal that will allow it to operate its power plants as efficiently as possible while meeting our environmental obligations. This approach, combined with the competitive market, is the best option for providing low cost electricity to consumers.

Any energy policy for Illinois needs to factor in not only the importance of IL coal but also the importance of Luminant's 12 power plants (9 coal, 3 gas) to Illinois' economy, electric reliability, and energy affordability. Vistra provides over $2 billion in annual economic activity in Illinois, produces enough electricity to power ~ 4.2 million homes, supports over 1,000 direct and 9,000 indirect jobs, serves over 700,000 retail customers, and supports the economy of over 80 Illinois counties via its Luminant generation and Homefield Energy and Dynegy Energy retail business.

Vistra's Luminant coal-fueled generation fleet in downstate Illinois is, except for Kincaid, in the Midwest ISO ("MISO") market, which is dominated by regulated utilities. These regulated competitors are allowed to receive in-state and out-of state subsidies (regulated rates) to cover their costs of operations while Vistra competes against those same companies in a common marketplace. Further, the MISO market design does not adequately compensate capacity for its reliability contribution. In the past 18 months, 20% of downstate Illinois' coal-fueled electricity capacity has shut down, due to this inequity and inability to recover its costs of operation. Thousands of additional downstate MW of capacity are at risk and moving closer to retirement each and every day. Vistra stands ready to work with policymakers to develop an energy policy that works for all of Illinois. In Illinois and every other state and market where we operate, we are committed to providing electricity to customers in a safe, efficient and cost-effective manner, which can involve both investing in our existing plants as well as in modern and fuel-diverse sources of generation.

Western Powder River Basin (PRB) Coal and IL Coal attributes and price

- Currently PRB coal, with significantly less sulfur content, costs ~$12.50 per ton compared to ~$40/ton for Illinois Basin coal.[1] On a Btu basis, PRB coal is ~$0.71/MMBtu and Illinois Basin coal is $1.79/MMBtu.
- Depending on market conditions, PRB coal prices can range from $9 to $15/ton. Illinois Basin coal prices can range from $30 to $50/ton.[2]
- In 2017, SNL Energy estimated the shipping cost of IL Basin coal at ~$10/ton and PRB at ~$22/ton, which is in line with current market conditions. Coupled with the prices above, the delivered prices would be $50 for IL Basin coal and $34.5 for PRB coal.
- Factoring the cost of transportation and the higher Btu content of Illinois Basin coals, PRB coal delivers for $1.96/MMBtu and Illinois Basin coal delivers for $2.23/MMBtu.
- In Ohio, there are advantages to using Illinois Basin Coal as PRB gets more expensive to transport and Ohio does not have as strict environmental regulations as Illinois. Many Ohio plants can take advantage of lower transportation costs since they receive coal by barge instead of rail.

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[1] Quotes from Coaldesk LLC
[2] Quotes from Coaldesk LLC

- Illinois Basin coals tend to cause higher operational and maintenance expenses that need to be factored into any decisions.
- Illinois coal does have a higher heat content, which would require less coal to be used to produce the same amount of electricity. However, even taking the heat content into account, the cost of Illinois Basin coal is higher than PRB coal in Illinois.
- The higher heat content of Illinois coal may provide lower carbon emissions than PRB coal; however, the wet scrubbers required to capture SO2 emissions from higher sulfur Illinois Basin coals use additional electricity (parasitic load) at the plant, impacting overall unit efficiency. That is, the parasitic load, along with the release of additional CO2 caused by wet scrubber technologies may offset a portion of the reductions in CO2.

Vistra's Commitment:
- Vistra will continue to evaluate opportunities to find competitively priced coal options and technologies that facilitate the ability to use the coal as a fuel source. Vistra and Dynegy have met with and continue to meet with coal suppliers and those offering new technologies.

Illinois tax policies discriminate against coal used for electricity generation:
- Vistra pays ~ $20 Million in sales tax per year on coal used in Illinois.
- Coal is the only electric generation fuel sourced taxed in Illinois as natural gas is exempt and nuclear fuel rods are leased.
- Electricity generators, regardless of fuel source, are also prohibited by IL statute from using the tax incentives commonly used by manufacturers for materials used in producing the final product.
- Prior to 2003, generators also received a sales tax break on the installation of pollution control equipment.
- The cost of coal and the shipment of that coal is a cost of doing business and is reflected in the prices that we charge for the electricity that we sell into the competitive electricity market.

Federal and State Environmental Policy and Vistra's obligations
- Federal Clean Air Act requirements, and other federal action, on SO2 and NOx emissions, and ICC disallowance of scrubber costs, pushed Illinois generators towards PRB coal decades ago.
- The Illinois Multi-pollutant Settlement (MPS) Rule imposes various restrictions on SO2, NOx, and mercury emissions that are stricter than federal requirements, limiting Vistra's ability to operate its fleet economically or consider the use of Illinois coal. The IPCB's proposed revisions to the MPS rule would allow for the economical operation of the fleet and help preserve as much of the fleet as possible but would not solve the underlying economic challenges caused by the MISO capacity market and low energy prices. Federal policies impose additional constraints at some units.
- Vistra's predecessor Dynegy invested over $2 billion in scrubbers and other emissions controls for its Illinois fleet in the last 12 years to meet federal and state regulations, and has cut emissions by ~90% since 1998.
- Dynegy's prior investments in scrubbers/injection systems at 5 plants allows Vistra to average compliance over the fleet and meet its multiple fleet wide state and federal obligations without having to install scrubbers at 4 other plants.
- Installing additional scrubbers at 4 plants, where not needed for environmental compliance, would cost hundreds of millions without any current mechanism to realistically recover the costs. For example, installing scrubbers at Edwards Power Plant is approximately $300 million alone.

Vistra's Comments on Peabody Energy's Submitted Comments to the FGD Task Force:

1. No Comment
2. Vistra largely agrees with this point.
3. Vistra largely agrees with this point and has used IL coal in Ohio units when competitive.
4. Vistra would point out that the fuel adjustment clause is no longer relevant since the utilities no longer own generation. I would add that coal, regardless of the sourced location, is the only fuel, used for electric generation that is taxed in Illinois, through sales and use taxes, placing coal-fueled EGU's at a competitive disadvantage with other generators using fuel rods or natural gas. Vistra pays approximately $20 million per year in sales/use taxes on coal used in Illinois. EGU's are also prohibited by IL statute from using the tax incentives commonly used by manufacturers for materials used in producing the final product . Prior to 2003, EGUs also received a tax break on the installation of pollution control equipment.
5. Vistra generally agrees with this point. Duck Creek has also received the same award as Coffeen as the cleanest burning plant on SO2 basis.
6. Vistra generally agrees
7. No Comment
8. Regarding price, generators would typically have an incentive to use the cheapest fuel source. Vistra would encourage the use of independent price sources and the price of delivered price of coal.
9. Generally True
10. Generally True
11. No Comment
12. Would agree that the cost estimates seem low, perhaps more of per EGU, than plant number. When Dynegy evaluated its fleet in 2015-2016 timeframe, on a plant-by-plant basis, to determine the total cost of conversion (what it would take to burn ILB coal), in terms of CAPEX, upgrades, chemicals, increased maintenance, liquidated damages from existing contracts, etc., and determined a range of approximately $100,000,000 to $1,000,000,000, from least expensive to most expensive plant. Even then, you would need to find a competitive coal contract. Even on presently un-scrubbed plants the estimated equipment costs exceeded $300,000,000 per plant. Dynegy and Ameren spent over $2 Billion for scrubber and mercury control installations collectively, on 7 EGU's, at four plant sites for MPS compliance. The challenge of recovering those costs out of a competitive energy market, combined with the broken MISO capacity market, has led to systemic challenges that threaten much of the EGU fleet in downstate Illinois with retirement.

Vistra's Comments Regarding JET Technologies / Case study on Kincaid Power Station:

Luminant's operation group recently met with JET representatives to hear a presentation regarding their technology and business model. The Luminant development group will review the details of JET's proposal and make an independent assessment about the feasibility of their proposed options, technologies, and economics. Luminant was not involved in the "case study" reported by JET. We cannot comment on the accuracy of their estimates or the feasibility of the study at this time. Kincaid is currently in compliance with all environmental regulations and with all components of its Consent Decree and is prepared to do so indefinitely.

Technical Evaluation of an Ammonia-Based SO_2 Scrubbing Technology's Potential Applicability to Vectren's A.B. Brown Generating Station

Prepared for

Frost Brown Todd, LLC

August 9, 2018

Prepared by

Katherine Dombrowski
Trimeric Corporation

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Executive Summary

Trimeric investigated the alternative of retrofitting Vectren's A.B. Brown coal-fired generating units with an ammonia-based SO_2 scrubber technology that could eliminate or materially reduce the wastewater discharge from the scrubbing process and produce commercially saleable agricultural fertilizer as a byproduct of the process. For this investigation, Trimeric gathered information about A.B. Brown Station and about ammonia-based scrubbing technology, reviewed publicly available data, and held several conversations with engineers from Marsulex Environmental Technologies (MET) and Jiangnan Environmental Technology (JET). Trimeric also visited three operating coal-fired plants with ammonia-based SO_2 scrubbing technology installed and operating.

Trimeric found that ammonia-based scrubbing is a commercially-available technology that can achieve high levels of SO_2 removal. The technology can produce a saleable fertilizer byproduct. If implemented, an ammonia-based scrubber could eliminate the concern that Vectren has about complying with U.S. Steam Electric Power Generating Effluent Limitations Guidelines (ELG) regulations. The technology has been successfully deployed in Poland and China at coal-fired power plants at a scale comparable to the A.B. Brown units and using similar equipment design to what would be used at A.B. Brown. Other technical aspects of the ammonia-based scrubber were evaluated, including process availability/reliability/maintenance, ammonia and ammonium sulfate handling safety, effect on the generating plant's water balance and byproducts, impact on ability to install carbon capture technologies, effect on other air emissions, and a preliminary economic analysis. With respect to these aspects, no adverse information was identified in Trimeric's investigation that would be likely to prevent the ammonia-based scrubbing technology from being a potentially viable candidate for an SO_2 removal technology for A.B. Brown. As to mercury emissions and particulate matter emissions, further investigation would be required to determine if additional mercury removal processes and/or particulate control technologies, both of which are commercially available, would need to be deployed along with an ammonia-based scrubber at A.B. Brown to meet current emissions limits.

1. Introduction

Vectren has proposed to retire its coal-fired generating assets at A.B. Brown and replace them with natural gas-fired generating assets. The coal-fired assets operate with dual alkali scrubbers that remove SO_2 from the flue gas to enable compliance with regulatory limits on SO_2 emissions. Vectren reported that these existing dual alkali scrubbers were expensive to operate and were beyond their expected useful life. Vectren evaluated the economics of replacing the existing dual alkali flue gas desulfurization (FGD) systems at A.B. Brown Units 1 and 2 with a limestone-based technology which is widely deployed across the United States. Vectren determined that the economics of scrubber replacement with a limestone forced oxidation system were not favorable because of the scrubber's capital cost and the likelihood of needing additional wastewater treatment equipment for compliance with future Effluent Limitation Guidelines.[1] However, Vectren did not report considering other FGD options in their decision to retire the coal-fired assets at A. B. Brown. Ammonia-based SO_2 scrubbers are one such FGD option; they have been widely deployed in Poland and China, and they have the potential to provide economic advantages over limestone scrubbing.

Trimeric Corporation was engaged by Frost Brown Todd, LLC to determine whether an ammonia-based scrubbing technology is a commercially-available SO_2 emissions control technology and whether the technology has potential technical viability as a replacement for the existing SO_2 emissions control technology at Vectren's A.B. Brown Generating Station. Trimeric evaluated key performance criteria for the ammonia-based scrubbing technology: its SO_2 removal performance, its ability to generate a saleable ammonium sulfate product, and its elimination of the need for wastewater treatment under the U.S. Steam Electric Power Generating Effluent Limitations Guidelines (ELG). Trimeric assessed the technology's availability at commercial-scale by assessing its deployment history with respect to the scale, process equipment fidelity, and application environments that are similar to A.B. Brown. Finally, Trimeric evaluated other technical considerations relevant to the technology's potential deployment at A.B. Brown, such as its reliability, effect on other air emissions and plant byproducts, its compatibility with the installation of future CO_2 controls, and a preliminary economic analysis.

The remainder of this report is structured as follows:

- Section 2: Methodology for Technology Assessment
- Section 3: Ammonia-based scrubbing Technology Discussion
- Section 4: Technology Assessment

[1] Verified (Public) Direct Testimony of Wayne D. Games, Vice President of Power Supply. Cause NO. 45052 (March 20, 2018).

2. Methodology for Technology Assessment

The objective of Trimeric's analysis for Frost Brown Todd, LLC was to determine whether ammonia-based scrubbing is a technically-viable, commercially-available SO_2 removal technology option for A.B. Brown. Trimeric's analysis was limited to the technical performance and commercial readiness of ammonia-based scrubbers; Trimeric did not determine whether installation of ammonia-based scrubbers is the best option for A.B. Brown.

Trimeric assessed the ammonia-based scrubbing technology for (1) its ability to meet key performance criteria for the successful technical and economic operation of the technology at Vectren's A.B. Brown Generating Station, and (2) its deployment history relevant to A.B. Brown's scale, expected process equipment configuration, and operating environment.

Key performance criteria critical to the technology's success as a potential replacement for the existing FGD scrubbers at A.B. Brown include (1) its SO_2 removal performance, (2) its ability to generate a saleable ammonium sulfate product, and (3) its elimination of the need for wastewater treatment under the U.S. Steam Electric Power Generating Effluent Limitations Guidelines (ELG). Other technical aspects of the ammonia-based scrubber were evaluated, including process availability/reliability/maintenance, ammonia and ammonium sulfate handling safety, effect on generating plant's water balance and byproducts, impact on ability to install carbon capture technologies, effect on other air emissions, and a preliminary economic analysis.

Data for Trimeric's evaluation were obtained from the following sources.

- Testimony of Wayne D. Games of Vectren Energy Delivery of Indiana, filed on March 20, 2018 with the Indiana Utility Regulatory Commission. This testimony includes the Revision 1 report that was issued on July 8, 2017 by Burns & McDonnell Engineering Company, Inc. entitled "A.B. Brown FGD Condition Assessment & Retrofit Cost Estimate." The A.B. Brown plant design parameters used as the basis for Trimeric's analysis were mostly obtained from this testimony, including the Burns & McDonnell report. The plant design criteria assumed for this analysis are summarized in Appendix A.
- Information obtained from the public domain including papers and presentations at technical conferences, company websites, and brochures.
- Information provided in conversations with engineers from Marsulex Environmental Technologies (MET) and Jiangnan Environmental Technology (JET), suppliers of ammonia-based SO_2 scrubbing technology.
- Information provided in test reports from JET, which JET authorized to be cited in this report.
- Plant tours of three sites which operate JET's ammonia-based SO_2 scrubbers.

3. Ammonia-based Scrubbing Technology Discussion

Ammonia-based scrubbing is a technology for reducing SO_2 emissions from the flue gas effluent of a coal-fired power plant. In this section of the report, the US suppliers for this technology are first discussed. Then, a basic process description is provided.

Suppliers of Ammonia-based Scrubbing Technology

Trimeric obtained information from two well established companies selling ammonia-based SO_2 scrubbers to the United States' coal-fired power market: Marsulex Environmental Technologies and Jiangnan Environmental Technology.

Ammonia-based scrubbing for flue gas desulfurization was developed by General Electric Environmental Services in the 1990s and later acquired by Marsulex Environmental Technologies (MET). MET offers multiple technologies for flue gas desulfurization, including ammonium sulfate, limestone, lime, and sodium hydroxide. MET has over 150 wet FGD systems installed in 22 countries. MET conducted the first field pilot of the ammonium sulfate technology at Dakota Gasification Company's (DGC) SynFuels Plant, which then led to installation of 350-MWe ammonia-based scrubbing unit at DGC in 1997. This scrubbing unit still operates today. MET's second installation was a 315-MWe unit that started operation in 2006 at an oil sand processing facility in Canada. MET has designed and installed scrubbers for applications with high to low sulfur loadings from oil refiners, coal-fired boilers and non-traditional sulfur-containing streams. MET considers its experience list proprietary, but MET did share that most of its recent installations have been concentrated in Poland and China. MET is in the process of constructing a small ammonia-based scrubber in the state of Louisiana.[2]

Jiangnan Environmental Technology (JET) is a US based subsidiary of Jiangsu New Century Jiangnan Environmental Protection Inc., Ltd (JNEP). JNEP began research on ammonia-based scrubbing technology in 1998 and licensed the technology to JET in 2014. JET markets the technology under the name Efficient Ammonia Desulfurization (EADS). JET has more than 300 ammonia-based flue gas desulfurization absorbers installed at over 150 different sites, all in China.[3] Over 85% of the EADS installations are on coal-fired units. EADS can be applied to units firing coal with sulfur content of 0.3% to 8%. JET's current technology configuration is labeled as a "4th generation" EADS system, which incorporates "ultra-sound enhanced deSO_X and PM-removal." The 4th generation EADS system was first deployed in 2015, and has since been deployed at over 50 installations. [4]

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[2] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[3] Repp, David, Ke Zhang, Peter Lu, JET-Inc. "Ammonia-Based Desulfurization Technology." *Power-Gen International.* Las Vegas, NV, December 5-7, 2017.

[4] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

Process Description

Basic process flow diagrams for the MET and JET systems can be found at their respective websites.[5,6] Flue gas is conveyed from the outlet of a particulate control device by an induced draft fan into the bottom of the absorber tower. The flue gas counter-currently contacts saturated ammonium sulfate slurry that is introduced into the absorber. Good contact between the gas and liquid is achieved through engineering design of the spraying system and the design of absorber column internals intended to direct the flow path of the gas and liquid. Contact with the slurry cools the flue gas close to its adiabatic saturation temperature. The heat from the flue gas evaporates water from the ammonium sulfate slurry, resulting in the production of ammonium sulfate crystals which will become the product of the scrubbing process. The reaction chemistry can be summarized in the following two reactions.

$$SO_2 + 2NH_3 + H_2O \rightarrow (NH_4)_2SO_3$$
$$(NH_4)_2SO_3 + \tfrac{1}{2}\,O_2 \rightarrow (NH_4)_2SO_4$$

The actual chemistry is more complicated, involving several intermediate steps: (1) absorption of SO_2 into water to form sulfurous acid, (2) the reaction of sulfurous acid with ammonium sulfate and sulfite to form ammonium bisulfite and bisulfate species, (3) the reaction of ammonia with the sulfurous acid, ammonium bisulfite and bisulfate to form ammonium sulfite and ammonium sulfate, (4) the addition of O_2 to oxidize ammonium sulfite to ammonium sulfate, and the addition of heat from the flue gas to evaporate water and crystallize ammonium sulfate solids. These reactions are described in a paper by MET.[7]

The scrubbed flue gas exits the top of the absorber after passing through mist eliminators and other equipment engineered to remove entrained liquid droplets and particulate matter from the gas. The scrubbed flue gas is exhausted through a chimney/stack.

The ammonium sulfate slurry flows down the absorber tower into a reaction tank. An oxidation air fan delivers air for the oxidation of ammonium sulfite to ammonium sulfate. The ammonia feed rate to the

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[5] Evans, Amy P., Claudia Miller, Steve Pouliot. "Operational Experience of Commercial, Full Scale Ammonia-Based Wet FGD for Over a Decade." *www.met.net.* August 20, 2009. http://www.met.net/Data/Sites/35/assets/Information-Library/Technical%20Papers/Operational%20Experience%20of%20Commercial,%20Full%20Scale%20Ammonia-based%20Wet%20FGD%20for%20Over%20a%20Decade%20-%20August%202009%20-%20Presented%20at%20Coal-Gen%202009.pdf (accessed July 31, 2018).

[6] "Application of EADS (Efficient Ammonia Desulfurization)." http://jet-inc.com/wp-content/uploads/2017/03/JET-Inc-EADS-Application-in-Coal-Fired-Boiler-FGD.pdf (accessed July 31, 2018).

[7] Evans, Amy P., Claudia Miller, Steve Pouliot. "Operational Experience of Commercial, Full Scale Ammonia-Based Wet FGD for Over a Decade." *www.met.net.* August 20, 2009. http://www.met.net/Data/Sites/35/assets/Information-Library/Technical%20Papers/Operational%20Experience%20of%20Commercial,%20Full%20Scale%20Ammonia-based%20Wet%20FGD%20for%20Over%20a%20Decade%20-%20August%202009%20-%20Presented%20at%20Coal-Gen%202009.pdf (accessed July 31, 2018).

reaction tank is controlled to maintain the desired pH in the reactor slurry. Ammonia is supplied either as aqueous ammonia (typically about 30% NH_3 in water) or as anhydrous ammonia.

The contents of the reaction tank are called the reaction tank slurry. The slurry consists of a mixture of ammonium sulfate solids (approximately 10-15 weight% of the slurry, according to JET[8]) and an aqueous phase liquid containing ammonium sulfite, sulfate, bisulfite, and bisulfate species. The reaction tank slurry is conveyed to the top of the absorber tower via slurry recirculation pumps. In a spray tower design, this slurry is continuously fed from the reaction tank to the spray headers in the absorber tower.

The reaction tank slurry can be further processed into an ammonium fertilizer product. An ammonia-based scrubber is typically designed to produce one of three types of product: a diluted slurry of ammonium sulfate fertilizer, a standard crystalline form of ammonium sulfate, or a hard granular production formed by compaction. The granular product can be blended with other fertilizers to form a specialty blend that is optimized for specific crops.

While the scrubbing of SO_2 from the flue gas is a continuous process, the production of fertilizer can be operated in a batch mode by periodically sending a bleed stream of slurry to the fertilizer processing area.

If the slurry form of ammonium sulfate product is desired, no further processing of the ammonium sulfate stream is required.

If a solid ammonium sulfate fertilizer is desired, then the slurry is first dewatered through a hydrocyclone in which the ammonium sulfate solids exit the bottom of the hydrocyclone along with some of the slurry liquid. The ammonium sulfate solids from the hydrocyclone bottoms are further dewatered in a centrifuge. The ammonium sulfate solids from the centrifuge are then dried to less than 0.5%-1% moisture in a dryer, and the dryer exhaust gas is treated to remove particulate matter before being exhausted to the atmosphere. The dried fertilizer product is cooled and then stored. At this point, the "standard" fertilizer product (it looks like crystals of sugar that are slightly rectangular in size) has been produced and can be packaged for sale. If a granular product is desired, then the standard product is formed into sheets and milled into the rounded, compacted product. This additional processing requires significant capital investment as it requires several pieces of equipment including conveyors and hammer mills.[9]

The majority of the slurry's liquid phase exits the top of the hydrocyclone and is typically combined with the centrifuge's liquid reject stream called the centrate. The combined stream can be returned in its entirety back to the reaction tank slurry and/or processed through a filter press. MET typically includes a filter press in its process design, while JET only uses the filter press when upstream particulate control

[8] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.
[9] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

devices provide insufficient removal of ash from the flue gas. The solids in the centrate consist primarily of fly ash captured in the ammonia scrubber, and the filter press reduces the moisture content of the fly ash cake to 30-40%. This fly ash cake can be mixed with other solids streams and landfilled; according to MET, this fly ash cake does not trigger hazardous waste classification.[10] The water removed by the filter press is either returned to the absorber or sprayed onto the ammonium sulfate product as it enters the dryer.

Process water is stored in a process water tank and conveyed to the absorber to make up for water lost through evaporation of the reaction tank slurry liquid to the flue gas and through water that leaves with the ammonium sulfate product and with the fly ash filter cake.

4. Technology Assessment

The technology assessment is organized into the following three subsections: key technical performance criteria,.commercial availability, and other considerations.

Key Performance Criteria for Ammonia-Based Scrubbing Technology

Trimeric assessed the key technical performance criteria for the ammonia-based scrubbing technology: SO_2 removal efficiency, the generation of a saleable ammonium sulfate fertilizer product, and the elimination of ELG-regulated streams.

SO_2 Removal

The requirements for SO_2 removal per A.B. Brown's Title V permit specify 0.426 lb SO_2/MMBtu when Unit 1 and Unit 2 operate simultaneously; the permit also specifies at least 90% SO_2 removal by the Unit 2 FGD scrubber. Today's limestone forced oxidation scrubbers are able to achieve significantly higher SO_2 removal; the Burns and McDonnell report used 98% SO_2 removal as the design basis for a new flue gas desulfurization unit. The ammonia-based scrubber data reviewed by Trimeric indicate that the technology can be designed to meet or exceed 98% SO_2 removal, which would translate to emissions of less than 0.12 lb SO_2 /MMBtu at A.B. Brown.

The supporting data for this conclusion are as follows:

- MET says it can guarantee 98% SO_2 removal.[11] The ammonia-based scrubber at DGC achieved greater than 93% SO_2 removal with a heavy residual/gaseous fuel containing 5-wt% sulfur, resulting in SO_2 outlet concentrations of approximately 750 mg/Nm^3 (or about 260 ppmv).[12]

[10] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[11] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[12] Evans, Amy P., Claudia Miller, Steve Pouliot. "Operational Experience of Commercial, Full Scale Ammonia-Based Wet FGD for Over a Decade." *www.met.net.* August 20, 2009. http://www.met.net/Data/Sites/35/assets/Information-

MET reports all of their installations were designed for 96% SO_2 removal or less; this removal level has been driven by market demand via regulatory requirements. MET has recently conducted pilot-scale testing that achieved greater than 98% SO_2 removal, but MET was unable to share the data with Trimeric at the time of this report.

- JET supplied test data summaries from four ammonia-based scrubbing units – two units were third generation EADS and two units were fourth generation EADS. The data indicate 98.5 to >99.8% SO_2 removal for inlet SO_2 concentrations ranging from 650 to 4000 ppm SO_2, dry basis at 6% O_2. The corresponding outlet SO_2 concentrations ranged from < 7 ppm to 18 ppm.

Generation of a Saleable Ammonium Sulfate Fertilizer Product

For each short-ton of SO_2 scrubbed by the ammonia-based scrubber, 3.9 short-tons of ammonium sulfate fertilizer will be produced per reaction chemistry. An ammonia-based scrubber at A.B. Brown designed for 98% SO_2 removal for a 3.38% S coal and operating with an annual capacity of 52%, would generate approximately 150,000 short-tons/year of ammonium sulfate fertilizer. This production rate would require approximately 40,000 short-tons/year of anhydrous ammonia.

The purity specifications for fertilizer in the United States are regulated by the individual states; however, buyers may have more stringent specifications.[13] MET reports that production and sale of the fertilizer from DGC (marketed as Dak-Sul 45) allows DGC to recover some of the costs of scrubbing the boiler emissions. The plant produces 145,000 tons annually.[14]

The purity specifications for fertilizer include maximum concentrations allowable for various metals. According to MET and JET, meeting the metals specifications for fertilizer has not been a problem for any of their ammonia-based scrubbers.[15,16,17] Trimeric calculated the expected metals concentration in the fertilizer for the units at A.B. Brown based on the ash and metals concentration in the coal and the

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Library/Technical%20Papers/Operational%20Experience%20of%20Commercial,%20Full%20Scale%20Ammonia-based%20Wet%20FGD%20for%20Over%20a%20Decade%20-%20August%202009%20-%20Presented%20at%20Coal-Gen%202009.pdf (accessed July 31, 2018).

[13] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[14] Evans, Amy P., Claudia Miller, Steve Pouliot. "Operational Experience of Commercial, Full Scale Ammonia-Based Wet FGD for Over a Decade." *www.met.net.* August 20, 2009. http://www.met.net/Data/Sites/35/assets/Information-Library/Technical%20Papers/Operational%20Experience%20of%20Commercial,%20Full%20Scale%20Ammonia-based%20Wet%20FGD%20for%20Over%20a%20Decade%20-%20August%202009%20-%20Presented%20at%20Coal-Gen%202009.pdf (accessed July 31, 2018).

[15] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[16] Evans, Amy P., MET (Marsulex Environmental Technologies). "Advanced Ammonium Sulfate Wet FGD." July 26, 2012. http://www.mcilvainecompany.com/Universal_Power/Subscriber/PowerDescriptionLinks/Amy%20Evans%20-%20Marsulex%20Environmental%20Technologies%20-%207-26-12.pdf (accessed July 31, 2018).

[17] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

following assumptions: (1) 80% of the coal ash becomes fly ash, (2) fly ash and the non-volatile metals are removed with 99.6% efficiency by the particulate control device, (3) the volatile (Hg) and semi-volatile (Se, As) metals and halogens (Cl) are not removed upstream of the FGD (a worst-case assumption), (4) fly ash and its associated metals are removed with 80% efficiency across the FGD, and (5) the metals removed by the FGD are fully incorporated into the ammonium sulfate product (i.e., no purge of fly ash with the centrate). Trimeric calculated that all metals concentrations in the fertilizer produced at A.B. Brown should be lower than typical metals specifications for the fertilizer, an example of which was provided on a confidential basis by MET. Filtering of the fly ash from the centrate would result in even lower metals concentrations in the fertilizer.

The ammonium sulfate fertilizer produced by ammonia-based scrubbing at a coal-fired power plant would include approximately 0.6% ammonium chloride formed from the reaction of coal chloride with the scrubbing reagent. Ammonium chloride is a fertilizer enriched in nitrogen on mass basis, as compared to ammonium sulfate.[18] Both MET and JET indicated that incorporation of ammonium chloride into the ammonium sulfate fertilizer product was not a product quality issue.

Based on the information gathered by Trimeric, the ammonium sulfate produced by an ammonia-based scrubber at A.B. Brown should be a saleable product, as compared to the FGD solid waste from the dual alkali system, which is currently landfilled. A limestone forced oxidation scrubber would generate a gypsum byproduct, which could likewise be sold under favorable market conditions.

Elimination of ELG-Regulated Streams

One of the potential advantages of an ammonia-based scrubber over a limestone-based scrubber is that the ammonia-based process might be operated so as to not produce any wastewater streams subject to ELG. In a traditional limestone-based scrubber, water is purged from the scrubber to maintain the chloride concentration in the scrubbing slurry below the design limits for the scrubber materials of construction. This purged waste stream can create a need for a significant capital investment in wastewater treatment equipment in order to comply with the pending ELG rule.

In an ammonia-based scrubber, chlorides react with ammonia to form ammonium chloride, which is a fertilizer that is incorporated into the ammonium sulfate product. Using the A.B. Brown configuration data from Appendix A, both MET and JET determined than an ammonia-based scrubber should be able to operate without any wastewater discharge.[19,20] The only purge stream from the MET absorber would be from the centrate and the hydrocyclone overflow; MET sprays this stream onto the ammonium sulfate product, upstream of the dryer, resulting in recovery of more fertilizer product and reducing

[18] *NUEweb*. 1999. http://nue.okstate.edu/N_Fertilizers/Ammonium_chloride.htm (accessed July 2018, 2018).
[19] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.
[20] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

fugitive dust emissions within the production facility.[21,22] As the chloride concentration in the coal increases, the amount of purged centrate liquid increases in order to maintain chloride concentration in the scrubbing slurry. MET reported that the limitation on the quantity of this purge stream comes from the ability to dry the sprayed product; this limitation would be reached around 0.2 weight% Cl in the coal.[23] JET typically returns all of the centrate and hydrocyclone overflow streams back to the absorber. JET offers a proprietary chlorine balancing system which allows for the further precipitation of ammonium chloride from the slurry. This system offers flexibility with respect to maintaining the composition of the slurry when firing high chloride coals.[24]

Discussion of Water Balance Streams

Water enters the process in the following streams:

- Flue gas: The flue gas entering the scrubber contains water vapor.
- Anhydrous ammonia: The anhydrous ammonia reagent is typically 99.6% pure; the balance of the reagent may or may not contain some water.
- Process water: Water is added to the scrubber to maintain water balance across the system (i.e., to make up for losses due to evaporation of slurry water into the flue gas). Process water is used for cleaning mist eliminators and other process internal equipment.

There are several water streams that are recycled internally within the ammonia-based scrubbing system:

- Hydrocyclone overflow: The hydrocyclone overflow stream is either returned to the reaction tank slurry or it is combined with the centrifuge waste stream for further processing in a filter press.
- Centrifuge waste water stream: The centrifuge waste stream consists of fly ash and water. This stream is either returned to the reaction tank slurry or sent through a filter press. The water removed by the filter press is either returned to the scrubber or sprayed onto the ammonium sulfate fertilizer product to recover more product and reduce dust formation from the product.

Water leaves the process with the following streams:

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[21] Evans, Amy P., Claudia Miller, Steve Pouliot. "Operational Experience of Commercial, Full Scale Ammonia-Based Wet FGD for Over a Decade." *www.met.net.* August 20, 2009. http://www.met.net/Data/Sites/35/assets/Information-Library/Technical%20Papers/Operational%20Experience%20of%20Commercial,%20Full%20Scale%20Ammonia-based%20Wet%20FGD%20for%20Over%20a%20Decade%20-%20August%202009%20-%20Presented%20at%20Coal-Gen%202009.pdf (accessed July 31, 2018).

[22] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[23] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[24] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

- Flue gas: As flue gas passes through the scrubber, water is evaporated from the slurry into the flue gas until the gas reaches its adiabatic saturation temperature.
- Water consumed by reaction: The reaction of one mole of SO_2 with two moles of NH_3 requires one mole of H_2O.
- Centrate waste: The centrate waste contains about 30-40% water after it has gone through a filter press – applicable only if a filter press is incorporated into the process design. The centrate liquid removed by the filter press can be sprayed onto the ammonium sulfate product as it enters the dryer.
- Ammonium sulfate product: The ammonium sulfate product is dried to < 1% moisture, leaving some small residual moisture in the product.
- Dryer exhaust: Water evaporated from the ammonium sulfate product is exhausted to atmosphere.

Analysis of Commercial Availability of Ammonia-based Scrubbers

Trimeric evaluated the commercial availability of ammonia-based scrubbers from a technical perspective. The evaluation methodology was modeled on metrics that the U.S. Department of Energy uses for assessing technology readiness levels. Namely, Trimeric evaluated whether the ammonia-based scrubbing technology has been commercially deployed in situations that approximate the scale, fidelity of process equipment, and application environment similar to the A. B. Brown Generating Station.

While the technology has been applied to various coal-based industrial sites in Europe and Asia and to a coal gasification unit in the United States, it has not been installed on a coal-fired electric generating station in the United States. Ammonia-based scrubbing technology is similar in many respects to limestone forced oxidation scrubbers which have seen widespread deployment in the United States.

Scale of Application

A.B. Brown consists of two coal-fired generating units, Units 1 and 2, each capable of generating 265 MW on a gross basis. Brown currently operates with separate scrubbers for Units 1 and 2. A replacement ammonia-based scrubber could likewise operate with two scrubbing trains. Both MET and JET claim commercial applications at the scale of the A.B. Brown Generating Units:

- MET's website lists an installation at Yanzhi Petrochemical Company Thermal Plant in China and Zaklady Azotowe Pulawy Heating and Power Plant in Poland. The Yanzhi scrubbers are two 100-MW units that commenced operation between the years 2010 and 2012. The installation at the Zaklady Azotowe Pulawy Heating and Power Plant consists of two 300-MW installations at industrial coal-fired boilers, one in 2012 and one in 2016.[25,26]

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[25] MET (Marsulex Environmental Technologies). 2018. http://www.met.net/wet-fgd-technologies-ammonium-sulfate.aspx (accessed July 31, 2018).

[26] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

- JET's largest installation is at a coal gasification unit, which uses a single module scrubber to treat a gas stream flow rate of 2 MM Nm^3/hr. This gas rate is the equivalent of flue gas generated by approximately 500-MWe generating unit. JET's experience list includes four other plants with absorber modules in the range of 200 to 300 MW equivalent, very similar to the unit size at A.B. Brown.[27] While a single larger scrubbing unit could be installed to treat the combined gas from Units 1 and 2, two separate units provide more operational flexibility for turndown.

Process Equipment Fidelity

An ammonia-based scrubbing system is composed of equipment that is similar to equipment used in limestone-based scrubbing: namely an absorber tower (typically an open spray tower or a spray/tray type tower), a reaction vessel, oxidation air blowers, slurry recirculation pumps, and a hydrocyclone dewatering system. According to MET, the spray tower diameter for the ammonia-based scrubber is similar to a limestone-based scrubber; the reaction tank for the ammonia-based scrubber will be larger because the oxidation rate is slower. The recycle pumps will be of a similar size for the two systems, but the pumps for the ammonia-based scrubber will operate at a slightly lower flow rate because the reagent to gas ratio is lower for the ammonia-based scrubber. All wet scrubbers (i.e., dual alkali, ammonia, limestone-based scrubbers) that do not employ flue gas reheat require a wet stack design. For units where a new stack is required, JET offers a design with the stack directly on top of (i.e., integrated into) the absorber vessel.[28]

The ammonia reagent is more corrosive than the limestone reagent and must be accounted for in the choice of materials of construction for the process equipment. The materials for an ammonia-based scrubber are not unusual as compared to other wet FGD designs. MET's material selections are based on corrosion tests conducted over a range of chloride concentrations in ammonium sulfate solution. JET's designs include polymer materials for many of the scrubber internals, including the demister, spray nozzles, and pump internals. For the installation at A.B. Brown with the firing of 0.1 weight% Cl coal, MET anticipates that the scrubber slurry would contain approximately 66,000 ppm Cl. Both MET and JET indicated the use of glass-flake lined steel absorber vessels. Trimeric's discussions with FGD engineers at JET's installations in China revealed problems with the quality of application of the glass flake lining. These engineers recommended using higher grade alloys, if possible, to reduce maintenance during scheduled outages. The inlet and outlet ducts of the scrubber are very corrosive environments for both limestone-based and ammonia-based scrubbers; in either case, the use of a highly corrosion resistant alloy like C276 would be used.

The reagent handling system will be designed for ammonia rather than limestone. It will consist of an ammonia unloading facility, an ammonia storage tank, ammonia feed pumps (if feeding aqueous ammonia) or a control valve for feeding anhydrous ammonia.

[27] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.
[28] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

The fertilizer processing equipment consists of equipment that is not typically found with a limestone-based scrubber, but the equipment is readily available: centrifuges, filter presses, dryers, and packaging machines. The equipment for dewatering of the solids requires a similar or smaller footprint than the solids handling equipment used in limestone-based scrubbers.

Application Environment

Ammonia-based scrubbers have been commercially installed in a wide range of industrial applications, including gas cleanup from coal-fired power plants, coal gasification units, oil refiners and other sulfur-containing streams. With respect to pulverized coal-fired power plant operations, the key application environmental factors to consider are coal type (including coal sulfur, chlorine, and trace metals concentrations),flue gas sulfuric acid content, flue gas temperature, and the variable nature of U.S. coal-fired power plant operations.

Both MET and JET have commercial installations of ammonia-based scrubbers at pulverized coal power generating facilities and at facilities firing coal with compositions similar to that fired at A.B. Brown:

- MET: MET reports that the 3.5% sulfur content of the A.B. Brown coal is within the range of sulfur content of the coals that MET has prepared designs. MET has prepared and constructed scrubbers to accommodate up to 4 – 5 weight% sulfur in the fuel. MET's installations in Poland operate on flue gas generated from pulverized coal. Some of MET's installations in China are at sites that more closely represent an electric utility application.
- JET: JET's test data were provided for coal-fired applications with SO_2 inlet concentrations ranging from 600 to 4000 ppm SO_2, dry basis, 6% O_2. For comparison, the flue gas at A.B. Brown would be expected to contain approximately 2600 ppm SO_2. JET reported that their installation experience includes coals with chloride contents around 0.1 weight%, similar to the coal chloride content at A.B. Brown.

Coal-fired plants firing high sulfur coals and equipped with an SCR can generate flue gases with significant concentrations of sulfuric acid. A.B. Brown is one such power plant; it uses a sorbent injection system to reduce sulfuric acid concentrations in the flue gas. However, even small amounts of sulfuric acid can react with ammonia in the scrubber to form ammonium sulfate particles that are not easily removed by a traditional scrubber design. Further investigation would be required to determine if additional particulate control technologies would need to be deployed with an ammonia-based scrubber at A.B. Brown to meet current particulate matter emission limits. Both MET and JET offer technologies that can be incorporated into the ammonia-based scrubber to reduce fine particulate matter that may form from the reaction of sulfuric acid in the flue gas with ammonia in the scrubber. The JET and MET technology offerings for fine particulate control are discussed in this report in the section "Effect on Other Air Emissions."

The design temperature for the A.B. Brown flue gas entering the FGD scrubber is 325°F. Both MET and JET indicated that this flue gas temperature will not pose any design issue for an ammonia-based scrubber.[29,30] According to JET, an ammonia-based scrubber using glass-flake lined steel as the material of construction can accommodate flue gas temperatures ranging from 130°C (266°F) to 170°C (338°F).[31] For higher flue gas temperatures, a water quench may be employed to cool the flue gas stream prior to entering the absorber.

Many of today's U.S. coal-fired power plants operate with unit load that varies with the demand for dispatch of the unit, and/or with extended periods where the unit is shut down in a reserve outage. Ammonia-based scrubbers are able to operate in a load-following mode. JET reports that the turndown ratio of their scrubber ranges from 30% to 110%,[32] which would enable the scrubber to operate at low unit loads. The ammonia-based scrubbing unit can circulate solvent ahead of the generating unit startup, so that the scrubbing unit is able to treat the first flue gas emerging from the unit.

Other Considerations

Trimeric evaluated other considerations for the deployment of the technology at A.B. Brown, including process availability/reliability/maintenance, ammonia and ammonium sulfate handling safety, effect on generating plant's water balance and byproducts, impact on ability to install carbon capture technologies, effect on other air emissions, and a preliminary economic analysis.

Process Availability, Reliability, Maintenance

Trimeric identified the following data for the availability, reliability, and maintenance of ammonia-based scrubbers:

- MET reports that the operational reliability of the ammonia-based scrubbers is equal to or greater than conventional wet FGD.[33]
- The site process engineers at the three JET installations visited by Trimeric indicated that the scrubber maintenance was conducted according to boiler maintenance schedule, which was anywhere from every six months to every two years. The site process engineers indicated that the absorbers were reliable between maintenance outages. The site process engineers

[29] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[30] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

[31] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

[32] Repp, David, Ke Zhang, Peter Lu, JET-Inc. "Ammonia-Based Desulfurization Technology." *Power-Gen International*. Las Vegas, NV, December 5-7, 2017.

[33] Evans, Amy P., Claudia Miller, Steve Pouliot. "Operational Experience of Commercial, Full Scale Ammonia-Based Wet FGD for Over a Decade." *www.met.net.* August 20, 2009. http://www.met.net/Data/Sites/35/assets/Information-Library/Technical%20Papers/Operational%20Experience%20of%20Commercial,%20Full%20Scale%20Ammonia-based%20Wet%20FGD%20for%20Over%20a%20Decade%20-%20August%202009%20-%20Presented%20at%20Coal-Gen%202009.pdf (accessed July 31, 2018).

indicated that maintenance repairs were focused on repairs to the glass flake lining of the vessel; they all recommended using higher grade alloys for construction.[34]

- JET designs for redundant trains for all moving parts (e.g., spare recirculation pumps and oxidation air blower). JET typically designs with one centralized fertilizer production facility for a site, but the facility includes a spare train.[35]
- Both MET and JET indicated that operation of the scrubber with ammonia reagent is less prone to maintenance issues associated with scaling as compared to operating with limestone reagent. Limestone-based scrubbers have a tendency to form a gypsum scale that is only moderately soluble in water (0.202 weight% at 20°C)[36]; great care with design of water washes and scrubber operating conditions is required to avoid scale formation. In contrast, the ammonium sulfate crystals that form in an ammonia-based scrubber are much more soluble in water (42.9 weight% at 20°C)[37]; a water wash is thus more effective in keeping mist eliminators and other internal equipment clean. In addition, MET operates the ammonia-scrubbing process in a sub-saturation mode on a periodic basis (frequency depends on unit load) in order to prevent crystals from accumulating on the process internals. The operation in the sub-saturation mode does not affect the overall generation rate of ammonium sulfate.

Ammonia Handling Safety

The operation of an ammonia-based scrubber requires the storage of significant quantities of ammonia reagent on the power plant site. Based on JET's recommendation for storage of a five-day supply of ammonia, approximately 1,000 tons (2,000,000 lb) of ammonia would be stored on site. This value would trigger OSHA's Process Safety Management (PSM) standard, which is applicable to the storage of (1) more than 10,000 lb of anhydrous ammonia, or (2) more than 15,000 lb of >44% ammonia solutions by weight.[38] If for some reason storing anhydrous ammonia is not practical, then the use of aqueous ammonia is a potential alternative. JET reported that the economic case for ammonia-based scrubbing still holds when using a 29% ammonia reagent; the economics are compromised when the reagent concentration approaches 19%.[39]

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[34] FGD Process Engineers at three JET installations in China. Personal Conversations. July 30 – August 3, 2018.
[35] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.
[36] In *CRC Handbook of Chemistry and Physics, 86th Edition*, by David R. (editor-in-chief) Lide, 8-113. Boca Raton, FL: Taylor & Francis Group, 2005.
[37] In *CRC Handbook of Chemistry and Physics, 86th Edition*, by David R. (editor-in-chief) Lide, 8-114. Boca Raton, FL: Taylor & Francis Group, 2005.

[38] *Process Safety Management*. 2000. https://www.osha.gov/Publications/osha3132.html (accessed July 31, 2018).
[39] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

JET reported that some of their facilities produce ammonia on site, while others have it delivered. JET has facilities that store as much or more ammonia as would be stored at A.B. Brown. JET reported having no safety issues associated with the storage of ammonia at any of its installations.[40]

Various regulations may apply to the safe storage and handling of anhydrous ammonia, including the American National Standards Institute (ANSI) for storage and handling of anhydrous ammonia (K61.1 – 1999), state regulations, and 29 CFR 1910.111, Storage and handling of anhydrous ammonia. The regulations address engineering design requirements for the construction, test and qualification of containers; location of storage containers; the design of appurtenances, piping, tubing, fittings, and hoses; safety relief devices; charging of containers; transfer of liquids; unloading operations, and electrical equipment and wiring.

The safety data sheet for anhydrous ammonia indicates the following Hazardous Materials Information System (HMIS) ratings: a flammability rating of 1 (materials must be moderately heated or exposed to high ambient temperatures before ignition will occur), a physical hazard rating of 2 (materials that are unstable and may undergo violent chemical changes at normal temperature and pressure with low risk for explosion.), a health rating of 3 (major injury likely unless prompt action is taken and medical treatment is given).[41]

Ammonium Sulfate Handling Safety

Ammonium sulfate is not a listed chemical in the OSHA PSM.[42] The safety data sheet for ammonium sulfate indicates a flammability Hazardous Materials Information System (HMIS) rating of 0 (material will not burn), a physical hazard HMIS rating of 0 (material is normally stable, even under fire conditions), a health HMIS rating of 1 (irritation or minor reversible injury possible). Ammonium sulfate may form a combustible dust in air during processing; best engineering practices for dust mitigation should be followed.[43] With respect to safety concerns, ammonium sulfate should not be confused with ammonium nitrate, which is also used as a fertilizer and is used along with fuel oil in explosive mixtures.

Effect on Generating Plant's Process Water Requirement

In comparison to a limestone or dual alkali-based scrubber, an ammonia-based scrubber should have a similar or lower process water requirement. All three scrubbing chemistries require process water for cleaning scrubber internals and for making up for water lost to evaporation into the flue gas and to the process chemistry. While limestone and dual-alkali scrubbers require a liquid purge stream (and the accompanying makeup water) to maintain chloride balance, ammonia-based scrubbers do not have this

[40] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

[41] "Ammonia Safety Data Sheet." February 15, 2018. https://www.airgas.com/msds/001003.pdf (accessed July 31, 2018).

[42] *Process Safety Management.* 2000. https://www.osha.gov/Publications/osha3132.html (accessed July 31, 2018).

[43] "Ammonium Sulfate Safety Data Sheet." December 28, 2014. https://beta-static.fishersci.com/content/dam/fishersci/en_US/documents/programs/education/regulatory-documents/sds/chemicals/chemicals-a/S25176A.pdf (accessed July 31, 2018).

purge stream as they maintain water balance by incorporation of ammonium chloride into the fertilizer product.

Effect on Generating Plant's Byproducts

The operation of the ammonia-based scrubber would not affect the quality of the fly ash captured in the upstream particulate control devices, assuming that no additional controls (e.g., activated carbon injection, or increased sorbent rate for sulfuric acid control) are needed upstream of the FGD for mercury control (see later subsection "Mercury Emissions").

The ammonia-based scrubber should generate a saleable ammonium sulfate fertilizer, as compared to the current dual alkali system which generates a waste slurry; a limestone-based scrubber can generate a gypsum product that could be sold to wall board manufacturers.

Impact on Ability to Install Carbon Capture Technologies

Trimeric evaluated the effect of an ammonia-based scrubber on the ability to later install CO_2 capture technology downstream of the scrubber. With regard to controlling CO_2 emissions from A.B. Brown, the ammonia-based scrubber offers several potential advantages for carbon capture:

- No CO_2 is produced by the ammonia-based scrubbing reaction. In contrast, 0.68 ton of CO_2 is released for each ton of SO_2 that is scrubbed in a limestone-based scrubber.
- The ammonia-based scrubbing system can achieve low flue gas concentrations of SO_2 which is a contaminant for many CO_2 removal technologies. Many CO_2 removal technologies require an additional scrubber after an existing limestone FGD to achieve the required inlet SO_2 concentrations (typically less than 10 ppm, but can be 2 ppm or lower). Use of an ammonia-based scrubber designed for very high SO_2 removal may either eliminate or reduce the size of an additional SO_2 scrubber. JET provided data for one of its installations showing SO_2 concentrations averaging between 2 and 4 ppm over two different days.[44]
- The ammonia-based scrubber is reported by JET to operate more energy efficiently than a limestone-based scrubber. Power consumption by the recirculation pumps is lower, since lower reagent to gas ratios are required.

Effect on Other Air Emissions

Trimeric evaluated the potential effect of the ammonia-based scrubber on non-SO_2 air emissions, including particulate matter, fine particulate matter, HCl, mercury, NO_X and ammonia. A significant fraction of many of these pollutants will have been removed by the upstream pollution control devices. For example, the ESP and fabric filters remove most of the particulate matter, the soda ash injection system removes most of the sulfuric acid and some HCl, some mercury is removed with the fly ash, and NOx is removed with the SCRs (but the SCRs also generate ammonia slip). Trimeric evaluated the fate of the pollutants that are in the flue gas as they are processed in the FGD system.

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[44] Repp, David (Sales Director, Jiangnan Environmental Technology). Email transmission. 07 August 2018.

Particulate Matter, Including Fine Particulate Matter, Emissions

Trimeric assessed the possible effects of an ammonia-based scrubber on the particulate matter emissions. The particles in flue gas exhaust from fine particulate matter (defined as particles less than 10 microns [PM_{10}] and particles less than 2.5 microns [$PM_{2.5}$]) to significantly coarser particles. Particulate matter emissions (which includes fine and coarse particles) at A.B. Brown are limited to 0.03 lb/MMBtu. A.B. Brown has a Title V limit for sulfuric acid mist emissions, but otherwise does not have a limit for emissions of fine particles. However, when major modifications are made to a point source, the proposed emissions of that modified source are reviewed against the New Source Performance Standards to determine if the source modification will affect the local area's ability to comply with National Ambient Air Quality Standards for fine particulate matter (PM_{10} and $PM_{2.5}$).[45] Fine particulate matter is more difficult to remove from flue gas than coarse particulate matter and it is a more significant contributor to stack opacity.

Particulate matter in an ammonia-based scrubber exhaust gas could come from several sources, each of which will be discussed in turn: fly ash, scrubber carryover, sulfuric acid mist, ammonium sulfate, and ammonium chloride.

Fly ash (filterable particulate matter): The flue gas entering the FGD will contain particulate matter that was not removed by the upstream particulate control devices. According to MET, fly ash particulate matter is removed across the ammonia-based scrubber at the same rate it is removed across a limestone-based scrubber, about 70-80%.

Scrubber carryover: Fine droplets of scrubber slurry can be entrained in the flue gas exhaust. Mist eliminators reduce the concentration of scrubber carryover in the exhaust.

Sulfuric acid mist (condensable particulate matter): The scrubber inlet flue gas will also contain sulfuric acid (H_2SO_4), which is generated by SO_2 oxidizing in the boiler and across the SCR catalyst and then condensing with water vapor at lower flue gas temperatures. A.B. Brown operates an alkaline sorbent injection system to control sulfuric acid emissions upstream of the FGD and thereby achieve regulatory compliance for sulfuric acid emissions. In contrast to SO_2 which is entirely in the gas phase and is removed with very high efficiency across an FGD scrubber, sulfuric acid condenses into a fine mist. This fine sulfuric acid mist is not efficiently removed by a wet scrubber; typical removals range anywhere from 20 to 70% across a wet FGD system. The facility's Title V permit limits stack emissions to 0.008 lb H_2SO_4 /MMBtu for Unit 1 and to 0.010 lb H_2SO_4 /MMBtu for Unit 2.

Ammonium sulfate (fine particulate matter): Sulfuric acid entering the scrubber will react with ammonia reagent to form very fine ammonium sulfate particles. These fine particles are not efficiently removed by a traditional wet FGD (absent additional control measures) and exit with the exhaust gas.

[45] "Fact Sheet." https://www.epa.gov/sites/production/files/2015-12/documents/20121012fs.pdf (accessed July 31, 2018).

Based on A.B. Brown's current sulfuric acid emission rate of 0.008 lb/MMBtu[46] and assuming 50% H_2SO_4 removal across the scrubber, the scrubber inlet H_2SO_4 emissions would be 0.016 lb H_2SO_4 /MMBtu. Reaction of this sulfuric acid with ammonia could create up to 0.02 lb $(NH_4)_2SO_4$/MMBtu, which, absent additional controls, would be a significant portion of the allowable 0.03 lb/MMBtu particulate emissions.

An engineering study would be required to determine the appropriate measures to control the emissions of fine particulate matter from an ammonia-based scrubber at A.B. Brown. There are several possible solutions which could be used individually or in combination to achieve compliance with the particulate matter limit and to reduce stack opacity.

- The efficiency of the sulfuric acid control system upstream of the FGD could be improved to reduce the resulting formation of ammonium sulfate particles in the FGD exhaust gas.
- An advanced mist elimination system can be installed to remove particulate matter at increased efficiency. MET offers a proprietary design in partnership with a mist eliminator supplier with the potential of removing 30-40% of the submicron particles; the mist eliminator is located above the spray levels and below the first set of traditional mist eliminators. The advanced mist elimination system adds about 2" H_2O pressure drop to the system; this added pressure drop must be considered when determining if the existing induced draft fan for moving the flue gas through the scrubber would be sufficient.
- MET offers a single stage wet electrostatic precipitator (wet ESP). Addition of a wet ESP requires a wider diameter absorber to accommodate the lower required gas velocities (8-9 feet/second for wet ESP versus 12 feet/second for the absorber).[47] Wet ESPs are effective at removing sulfuric acid mist, fine particulate matter, and scrubber carryover. EPRI has reported performance data for wet ESPs ranging from 60-80% capture of fine particles and sulfuric acid mist with a single field wet ESP, up to 98.9% capture with multiple fields.[48] MET's DGC installation incorporated a wet ESP, as the inlet sulfuric acid concentration was higher than the design specification. A wet ESP is incorporated into MET's European installations to meet a European Union particulate matter emissions limit of 10 mg/Nm^3 at 6% O_2 (~0.008 lb/MMBtu); however, MET's European installations do not encounter high inlet sulfuric acid concentrations.
- JET offers an acoustic agglomeration technology that is incorporated into its 4th generation EADS technology. JET reports that the technology agglomerates submicron particles; however, at the time of this report, JET did not have particle size distribution data available to share. JET provided particulate matter emissions data from performance tests at four installations; the particulate matter emissions ranged from 0.002 to 0.011 lb/MMBtu, which are below the 0.03 lb/MMBtu regulatory limit for A.B. Brown. JET reported that it can meet the current particulate

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[46] Sulfuric Acid Mist (H_2SO_4) Emissions Test Report for A.B. Brown Generating Station Unit #2, Air Quality Services, Evansville, IN, August 14-17, 2017.
[47] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.
[48] *SO3 Mitigation Guide Update,* EPRI, Palo Alto, CA: 2004. 1004168.

matter emissions limit for A.B. Brown with the current sulfuric acid concentrations at the FGD inlet, so long as the inlet particulate matter loading to the scrubber is less than 0.05 lb/MMBtu.[49]

The dryer exhaust would be a point source of particulate matter emissions within the ammonium sulfate fertilizer production facility; however, the exhaust gas flow rate from the dryer would be much smaller than the flue gas exhaust gas flow rate from the scrubber. Control of particulate matter emissions from ammonium sulfate manufacturing plants is achieved by installation of an emission control system, typically a venturi scrubber.[50]

HCl Emissions

The Mercury and Air Toxics Standard regulates HCl emissions from units such as A.B. Brown to 0.002 lb HCl/MMBtu; MATS alternatively allows for coal-fired units to demonstrate compliance with HCl emissions by showing that the wet-scrubbed unit has controlled SO_2 emissions to less than 0.2 lb SO_2/MMBtu. A.B. Brown fires a coal with a coal chloride concentration of about 0.1 weight%, which is equivalent to 0.075 lb HCl/MMBtu. The sorbent injection system at A.B. Brown may capture approximately half of the HCl,[51] reducing the FGD inlet concentrations to about 0.035 lb HCl/MMBtu. HCl entering flue gas desulfurization systems, whether ammonia-based or limestone-based, will be removed with high efficiency. JET did not have data on scrubber removal efficiencies of HCl, as China does not regulate HCl. MET's measurements of HCl emissions from European emissions shows HCl removed at levels of 99+%, with the caveat that the coal at these installations had a lower chloride content then the coal at A.B. Brown.[52] Assuming 98% HCl removal (same as the design SO_2 removal), the expected HCl emissions would be <0.001 lb/MMBtu, which is below the MATS regulatory limit of 0.002 lb/MMBtu. Alternatively, A.B. Brown could demonstrate compliance via its SO_2 emissions. At 98% SO_2 removal, the SO_2 emissions would be 0.12 lb/MMBtu, which is meets the 0.2 lb SO_2/MMBtu limit to forego direct HCl emissions measurements to demonstrate compliance.

Mercury Emissions

Under the Mercury and Air Toxics Standard, A.B. Brown Generating Station must meet a mercury emissions limit of 1.2 lb/TBtu. A.B. Brown currently meets this limit by adsorption of some of the gas-phase mercury to the fly ash, oxidation of mercury in the SCR and then its subsequent removal in the FGD scrubber, and the use of a mercury re-emissions additive to control FGD re-emissions.[53] Mercury re-

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[49] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

[50] U.S. Environmental Protection Agency. Ammonium Sulfate Manufacture – Background Information for Proposed Emission Standards. EPA-450/3-79-034a. December 1979.

[51] Gray, Sterling M., Jim B. Jarvis, and Steven W. Kosler. "Combined Mercury and SO3 Removal Using SBS Injection." *Power.* July 1, 2014. https://www.powermag.com/combined-mercury-and-so3-removal-using-sbs-injection/?pagenum=4 (accessed July 31, 2018).

[52] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[53] Verified (Public) Direct Testimony of Wayne D. Games, Vice President of Power Supply. Cause NO. 45052 (March 20, 2018).

emission is a phenomenon wherein scrubber mercury chemically transforms to a species that is not soluble in the scrubber liquor and is thus re-emitted to the stack gas.

Neither MET nor JET provided sufficient data for Trimeric to assess mercury removal across an ammonia-based scrubber; installed units in Europe and China have not had to comply with a mercury emissions limit. If re-emissions were an issue for ammonia chemistry, then strategies similar to those employed in limestone-based scrubbing, such as ORP control and/or the use of mercury re-emissions additive, could be tested for their effectiveness. If these strategies were not effective, then A.B. Brown may be able to achieve mercury compliance with one or more of the following approaches:

- Improved sulfuric acid controls, which would increase mercury removal by the fly ash, thus reducing the mercury load into the scrubber;
- Use of activated carbon injection to adsorb mercury and remove it in the particulate control devices. In this case, care would be needed in the selection of carbon type and injection rate to preserve the fly ash for beneficial reuse.

Nitrogen Oxide Emissions

Nitrogen oxides (NO_X) at A.B. Brown are controlled via low NO_X burners, low combustion air ratios, and an SCR. JET provided test data from four sites that show modest additional removal (5% – 25%) of NO_X by the ammonia-based scrubber. Little NO_X removal is expected because nitric oxide (NO) is not soluble in water, and nitric oxide does not react with ammonia at the operating temperature of the scrubber. Nitrogen dioxide (NO_2) is water soluble and would be partially removed by the scrubber, but little NO_2 would be present in the FGD inlet flue gas for a unit equipped with SCR.

Ammonia Emissions

A.B. Brown's Title V operating permit does not address ammonia emissions. Both MET and JET provided data for expected ammonia emissions from an ammonia-based scrubber:

- MET has a proprietary design to maintain ammonia slip to less than 10 ppmv, wet basis.[54] MET conveyed that the expected operating pH (of 5.2) and temperature at A.B. Brown are conducive to maintaining ammonia emissions below 10 ppm.
- JET indicated a typical ammonia emissions guarantee for U.S. applications is less than 5 ppm.[55] Test report data supplied by JET indicated ammonia emission ranging from 0.3 to 7.0 ppm.

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[54] Evans, Amy P., Claudia Miller, Steve Pouliot. "Operational Experience of Commercial, Full Scale Ammonia-Based Wet FGD for Over a Decade." *www.met.net.* August 20, 2009. http://www.met.net/Data/Sites/35/assets/Information-Library/Technical%20Papers/Operational%20Experience%20of%20Commercial,%20Full%20Scale%20Ammonia-based%20Wet%20FGD%20for%20Over%20a%20Decade%20-%20August%202009%20-%20Presented%20at%20Coal-Gen%202009.pdf (accessed July 31, 2018).

[55] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

Economic Analysis

An economic analysis of ammonia-based scrubbing technology must consider the coal sulfur content, availability and delivered price for ammonia, the regional market place for ammonium sulfate, the ability to reuse and/or retrofit the existing FGD and other existing infrastructure (e.g., the induced draft fan), the new infrastructure required for receiving, handling, and storing ammonia reagent, the available transportation for reagents and products, the desired return-on-investment model, and other factors. Trimeric performed a preliminary analysis of each of these factors, as described below; a full economic assessment was beyond the scope of this report.

Coal Sulfur Content

The production rate of ammonium sulfate fertilizer is driven by size of the power plant (i.e., amount of coal combusted) and the coal sulfur content. MET has a rule of thumb that if the coal sulfur is 2% or greater (such as it is at AB Brown, which has 3.4% S), then the economics for an ammonia scrubber can be very favorable due to the high production rates of ammonium sulfate fertilizer.[56]

The economics of the ammonia-based scrubbing technology improve with higher sulfur coals and with higher SO_2 removal efficiency. Therefore, the ability to fire higher sulfur coals than what Vectren is currently firing could provide a further cost advantage to the unit. Higher sulfur coals are typically cheaper than lower sulfur coals, and coal feedstock typically contributes over 80% of the variable operating costs for a coal-fired generating unit.[57]

Availability and Delivered Price for Ammonia; Regional Market for Ammonium Sulfate

Another key to viable economics of an ammonia-based scrubber is the availability of ammonia at a competitive price. To date, most of the installations of MET's ammonia scrubbers are at sites that have ammonia readily available or produce it on site.[58] Not having ammonia source on site implies a longer payback period versus a limestone scrubber. Per MET, the amount of ammonium sulfate generated at A.B. Brown is significant and favors the economics for application of the technology, even though ammonia is not produced on site.[59]

When operating at an annual capacity factor of 52%, the anhydrous ammonia required would be about 40,000 short tons per year. In comparison, an ammonia production facility is considered small scale when under 200,000 short tons per year, with some production plants as small as 30,000 tons/year.

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[56] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[57] Connell, D. Opportunities for New Technology in Coal Mining and Beneficiation; In Proceedings of the National Coal Council Annual Spring Meeting 2018, Washington, DC, April 2018. Available: http://www.nationalcoalcouncil.org/page-Meeting-Presentations.html

[58] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[59] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

Ammonia production capacity in the US was 15 million tons/year in 2015.[60] Approximately 90% of US ammonia consumption was for fertilizer use.[61]

Natural gas feedstocks account for more than 95% of ammonia tonnage, and thus the price of ammonia and fertilizer is tied to natural gas prices.[62] Trimeric found a range in reported prices for anhydrous ammonia and ammonium sulfate.

- **Anhydrous ammonia.** MET recommended using an anhydrous ammonia cost of $370-375/ton to be reflective of what a power plant would pay for the reagent.[63] JET recommended an anhydrous ammonia cost of $300/ton.[64]
- **Ammonium sulfate.** MET indicated that the wholesale price for standard grade ammonium sulfate is $100-$120/ton, while the wholesale price for compacted ammonium sulfate ranges from $245-$280/ton. A power plant producing ammonium sulfate would receive a price less than these wholesale values.[65] JET indicated that a power plant might receive $135/ton of ammonium sulfate.[66]

Differences in assumptions for shipping distances (which were not specified) may play a significant part in the variation in prices. Trimeric is not an expert in ammonia or fertilizer markets and cannot validate the applicability of any of these reported values to A.B. Brown. A detailed economic analysis performed by experts with knowledge of local markets is recommended.

For the sake of understanding the impact of pricing on the potential product margin, Trimeric evaluated the cost and revenue streams for the ammonia-based scrubber for three different scenarios: (1) using JET's suggested costs for ammonia and fertilizer, (2) using MET's suggested costs for ammonia and the standard fertilizer product, and (3) using MET's suggested data for ammonia and the compacted fertilizer product. These calculations were performed assuming 40,000 ton/year of ammonia use and 150,000 ton/year of ammonium sulfate production, based on 52% annual capacity factor for the two units. As shown in the table below, the annual margin between product and reagent costs could range

[60] Brown, Trevor. "Small-scale ammonia production is the next big thing." *Ammonia Industry.* May 10, 2018. https://ammoniaindustry.com/small-scale-ammonia-production-is-the-next-big-thing/ (accessed July 31, 2018).

[61] Brown, Trevor. "2016 in preview: US ammonia capacity to increase by a third." *Ammonia Industry.* January 12, 2016. https://ammoniaindustry.com/2016-in-preview-us-ammonia-capacity-to-increase-by-a-third/ (accessed July 31, 2018).

[62] "Gas as fertilizer feedstock." *PetroWiki.* July 16, 2015. https://petrowiki.org/Gas_as_fertilizer_feedstock (accessed July 31, 2018).

[63] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[64] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

[65] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.

[66] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.

from break-even (under the more conservative assumptions from MET) to as high as $27MM/year when making the compacted product.

Scenario #	Cost of NH_3 ($/ton)	Price of AS ($/ton)	Net annual difference in product revenue vs reagent cost ($/yr): (price of AS x ton/yr of AS – cost of NH_3 x ton/yr of NH_3)
JET	300	135	$8.25MM
MET Scenario #1 Standard Product	375	100	$0MM
MET Scenario #2 Compacted Product	375	280	$27MM

The type of final fertilizer product produced would be dependent on the contractual requirement with the off-taker. The plant would typically be designed to produce a single type of fertilizer product based on the product economics, such that the investment of equipment to make the standard crystals or the compacted product would only be made if the economics justified that product stream.

Trimeric asked JET about possible concerns with saturating the local fertilizer marker. JET reported that market saturation would not be an issue for the first several installations in the US market; the actual number of plants that would saturate the market is not known as it would depend on the technology's adoption rate. If the US market were to saturate, the next desirable markets are in Mexico and Canada, then South America. JET reported that total ammonium sulfate demand in North America is about 6 MM metric tons this year, and is expected to grow over the next four years.

Other operating costs

JET reported that non-reagent operating costs for an ammonia-based scrubber are below limestone scrubbing costs due to lower slurry recirculation rates resulting in lower power consumption.[67] MET also reported that the ammonia-based scrubber has lower circulation rates, but that the effect on overall power consumption is not significant enough to take into account in their economic analysis.[68]

Capital costs

MET indicated that the initial capital cost is 30-40% more expensive than a limestone scrubber when the fertilizer plant is included.[69] JET indicated that the capital cost is on par with that of a limestone scrubber.[70]

[67] Repp, David (Sales Director, Jiangnan Environmental Technology). Personal Conversations. 3 and 18 July 2018.
[68] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.
[69] Evans, Amy (Director of FGD Technology and Licensing, Marsulex Environmental Technology). Personal Conversations. 9, 12, and 19 July 2018.
[70] JET Brochure provided to K. Dombrowski on 31 July 2018.

Ability to Reuse Existing FGD Infrastructure
The existing dual alkali scrubber at A.B. Brown consists of several pieces of equipment that might be repurposed for an ammonia-based scrubber, including the induced draft fan, the absorber tower and reaction tank, the oxidation air blowers, the recirculation pumps, tanks, duct work, and chimney. This equipment would need to be in good condition or capable of being refurbished, and this equipment would need to be appropriately sized. An inspection conducted by Burns and McDonnell indicated that the lifetime of some of the existing FGD equipment may be very limited; however, this report appears to be based upon visual inspection of the external vessels, with no detailed metallographic analysis.[71] A more detailed structural inspection would be recommended to determine what existing equipment could be reused.

According to JET, the economics of the ammonia-based scrubber are viable, even if none of the existing FGD equipment is reused; JET prepared its economic analysis by assuming that the induced draft fan, chimney, and some connecting ductwork can be reused. The induced draft fan provides the motive force for conveying flue gas through the FGD scrubber. The pressure drop across the ammonia scrubber will be lower than a traditional scrubber, opening the possibility that the ID fan could be used in a scrubber retrofit. A detailed analysis would need to account for actual duct runs, pressure drop across scrubber, including any additional equipment such as advanced mist eliminators or wet ESPs that may be needed. If the induced draft fan and/or chimney could not be re-used, the payback period for the project would be lengthened.

New Infrastructure Required for Receiving, Handling, and Storing Ammonia Reagent
The ammonia reagent system for an ammonia-based scrubber will be larger than for ammonia system for the existing SCR, and will likely be a different reagent type. New infrastructure would be required, which would likely be provided by the ammonia-based scrubbing supplier.

Available transportation for reagents and products
The A.B. Brown Generating Station has rail and highway access for transport of anhydrous ammonia reagent and ammonium sulfate product.

Desired return-on-investment, contracting models, etc.
Trimeric did not complete a return-on-investment (ROI) analysis for the project, as this exercise was beyond the scope of this report. An ROI analysis would need to reconcile the expected life of a typical new scrubber (which is typically about 30 years) to the expected remaining life for the balance of plant at A.B. Brown. The return on investment would need to be evaluated against project and contract risks, including the Engineering, Procurement, and Construction (EPC) contract and the contract for the offtake of the ammonium sulfate product.

[71] Verified (Public) Direct Testimony of Wayne D. Games, Vice President of Power Supply. Cause NO. 45052 (March 20, 2018).

While owning and operating a fertilizer production facility would be unusual for a coal-fired electric generating plant in the United States, this function can be outsourced under a long-term contract if the utility is unable or unwilling to take on the responsibility. Various business models may be possible, such as Build, Own, and Operate (BOO) or EPC and Operation.

Appendix A – Design Criteria Assumed for A.B. Brown

Parameter	AB Brown	Source of Data / Comments
Unit size	U1: 245 MW net, 265 MW gross U2: 245 MW net, 265 MW gross	Vectren testimony by Wayne D. Games
Flue gas at Scrubber Inlet	U1: 2,898,000 lb/hr U1: 922,000 acfm U2: 2,870,000 lb/hr U2: 913,000 acfm	Burns and McDonnell report (BMcD report)
Unit heat rate	U1: 11,576 Btu/kwh net U2: 11,007 Btu/kwh net	Vectren testimony
Load profile	Cycling; max ramp rate of 3 MWs/minute	Vectren testimony
Boiler type	Dry bottom, pulverized coal-fired boiler	Title V permit
Annual capacity factor	52% - 2017 actual	Vectren testimony
Air Heater Outlet Temperature	325°F	BMcD report
Coal type	Bituminous	Vectren testimony
Coal sulfur	3.38% S, as-received	Coal analysis by Standard Laboratories BMcD report: 3.75% S as received; 6.7 lb SO_2/MMBtu
Coal moisture	11.62% H_2O	Coal analysis by Standard Laboratories for Sunrise Coal, LLC
Coal chlorine	977 μg/g, dry; this is 0.0977 wt% Cl	Coal analysis by Standard Laboratories
Coal arsenic	4.6 μg/g, dry	Coal analysis by Standard Laboratories
Coal cadmium	0.49 μg/g, dry	Coal analysis by Standard Laboratories
Coal chromium	16 μg/g, dry	Coal analysis by Standard Laboratories
Coal lead	6.2 μg/g, dry	Coal analysis by Standard Laboratories
Coal mercury	0.077 μg/g, dry	Coal analysis by Standard Laboratories
Coal selenium	1.9 μg/g, dry	Coal analysis by Standard Laboratories
Coal ash aluminum oxide	19.84%	
Coal ash calcium oxide	1.82%	
Coal ash ferric oxide	21.28%	
Coal ash	0.88%	

Parameter	AB Brown	Source of Data / Comments
magnesium oxide		
Coal ash sodium oxide	0.76%	
Coal ash manganese dioxide	0.06%	
Coal HHV	11,486 Btu/lb as received coal	Coal analysis by Standard Laboratories
Existing SO_2 control	Dual alkali scrubber	Vectren testimony
Design SO_2 removal for new FGD	>=98% SO_2 removal	BMcD scrubber replacement analysis targeted >=98% SO_2 removal Title V permit for U2 specifies BACT with SO_2 controlled to at least 90.0%
SO_2 limit	0.855 lb SO_2/MMBtu on one hour average for U1 alone; 0.426 lb SO_2/MMBtu one hour average for U1/U2 simultaneously operating; 0.69 lb SO_2/MMBtu on thirty-day rolling average for U2 anytime it is operating, whether alone or with U1	From Title V permit, issued 11/28/2017
NO_X controls	Low excess air, low-NO_X burners, and SCRs for U1 and U2	Title V permit
NO_X limit	0.6 lb nitrogen oxides/MMBtu	Title V permit limit for U2
NH_3 limit	None specified	NH_3 is not addressed in Title V permit
HCl limit	None specified	No limit found in the Title V permit; it appears Vectren was able to get quarterly testing approved (rather than continuous testing that was initially specified in the permit). MATS does not require reported for units meeting SO_2 emissions < 0.2 lb/MMBtu
Hg controls	Organosulfide mercury re-emission additive for the FGD, plus co-benefit removal from SCR, particulate control devices, and FGD	Vectren testimony
Hg limit	< 1.2 lb/TBtu	MATS limit

Parameter	AB Brown	Source of Data / Comments
PM Control	U1: Fabric filter U2: ESP	BMcD report
PM limit	0.03 lb PM/MMBtu	Title V permit limit specified for U2 emissions No specification found for U1 other than to control with ESP with minimum collection efficiency of 99.6% when burning coal with maximum ash content of 10%, minimum sulfur content of 2.5% and minimum heat content of 11,000 Btu/lb
H_2SO_4 controls	Soda ash injection directly upstream of SCR	BMcD report
H_2SO_4 limit	Permit limit is H_2SO_4 emission limit of 0.008 lb/MMBtu for U1 and 0.010 lb/MMBtu for U2	Title V permit limit
Wastewater treatment	Physical/chemical system with organosulfides, coagulants, flocculants	Vectren testimony
Fate of FGD solids	Landfilled on site	Vectren testimony
Fate of fly ash	Sold for beneficial reuse in cement	Vectren testimony
Transit access	Rail access Highway access Near Ohio River	Vectren testimony