

PSCW Docket # 6690-CE-193

**Application for Certificate of Authority
Weston Unit 3 Multi-Pollutant Control Technology Project**

for

Wisconsin Public Service Corporation

PUBLIC VERSION



May 2012

**BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN**

**Application of Wisconsin Public Service
Corporation for a Certificate of Authority
To Construct and Place in Operation a Multi-Pollutant Control Technology for the Weston
Unit 3 Generating Unit Located Near Wausau,
Wisconsin**

APPLICATION

Wisconsin Public Service Corporation (WPS) applies pursuant to Section 196.49 of the Wisconsin Statutes and Chapter PSC 112 of the Wisconsin Administrative Code for a Certificate of Authority to construct and place in operation a Multi-Pollutant Control Technology system (ReACT) for the Weston Unit 3 generating unit located at WPS's Weston Generating Station near Wausau, Wisconsin.

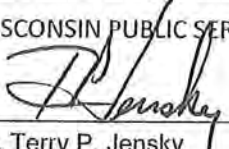
WPS is a public utility corporation organized and existing under the laws of the State of Wisconsin with its principal office located at 600 North Adams Street, Green Bay, Wisconsin 54307.

As shown in the attached Project Description and Justification, the public convenience and necessity require the construction and operation of the ReACT system. *See Wis. Admin. Code § PSC 112.07(1).* The proposed ReACT system will not impair the efficiency of the service of WPS, will not provide facilities in excess of future requirements, and will not add to the cost of service without proportionately increasing the value of service. *See Wis. Stat. § 196.49(3)(b).*

WHEREFORE, WISCONSIN PUBLIC SERVICE CORPORATION respectfully requests that the Commission issue a Certificate of Authority authorizing WPS to construct and place in operation a ReACT system for the Weston Unit 3 generating unit at WPS's Generating Station located near Wausau, Wisconsin.

Respectfully submitted,

WISCONSIN PUBLIC SERVICE CORPORATION



Mr. Terry P. Jensky
Vice President – Generation Assets

5-7-12
Dated: May 7, 2012

Certificate of Authority
Weston Unit 3 Multi-Pollutant Control Technology Project

Project Description and Justification

PUBLIC VERSION

Wisconsin Public Service Corporation
Green Bay, Wisconsin

May 2012

Table of Contents

1.0	PROJECT DESCRIPTION.....	3
1.1	SELECTED TECHNOLOGY	6
1.2	WESTON UNIT 3 CONSTRUCTABILITY SUMMARY FOR ReACT SYSTEMS	10
1.3	CONSTRUCTION APPROACH.....	10
1.4	MILESTONE SCHEDULE	12
2.0	COST AND FINANCING	13
2.1	ESTIMATED CAPITAL COST AND CASHFLOW	13
2.2	FINANCING MECHANISM	15
3.0	NEED AND ALTERNATIVE OPTIONS ANALYSIS	16
3.1	PLANNING FOR AIR EMISSIONS REGULATORY REQUIREMENTS.....	16
3.2	EMISSION COMPLIANCE PLANNING PROCESS	21
3.3	ECONOMIC ANALYSIS OF ALTERNATIVES.....	21
4.0	OPERATING PARAMETERS	23
4.1	COST OF OPERATION.....	23
4.2	OPERATING CHARACTERISTICS	24
4.3	EFFECT ON QUALITY AND RELIABILITY OPERATING CHARACTERISTICS.....	27
4.4	START-UP AND COMMISSIONING	27
5.0	DESCRIPTION AND COST OF PROPERTY BEING REPLACED.....	29
5.1	EQUIPMENT REMOVAL AND RELOCATION	29
6.0	EMISSIONS CONTROL TECHNOLOGY SELECTION	30
6.1	TECHNOLOGY SELECTION PROCESS	30
6.2	SUMMARY OF TECHNOLOGY SELECTION.....	30
6.3	ADDITIONAL TECHNOLOGY ATTRIBUTES THAT SUPPORT SELECTION OF ReACT.....	31
7.0	ENVIRONMENTAL IMPACTS AND PERMITS	33
7.1	MAPS AND DRAWINGS OF THE PROPOSED PROJECT SITE	33
7.2	EMISSIONS REDUCTIONS	33
7.3	PROXIMITY TO FLOODPLAINS	33
7.4	INFORMATION ON APPLICABLE ENVIRONMENTAL FACTORS	33
7.5	LIST OF PERMITS AND APPROVALS REQUIRED	36
8.0	DESIGNATION OF PUBLIC UTILITIES AND OTHER AFFECTED	39
	APPENDIX A.....	40

APPENDIX B.....	44
B.1 ABSTRACT	44
B.2 PURPOSE.....	44
B.3 KEY ASSUMPTIONS	45
B.4 PLANNING FUTURES.....	46
B.5 COMPLIANCE OPTIONS	49
B.6 COMPLIANCE STRATEGIES.....	50
B.7 EXPANSION PLANS	50
B.8 METHODOLOGY	50
B.9 RESULTS.....	50
B.10 CONCLUSIONS	54
APPENDIX C.....	56
C.1 TECHNOLOGY PROCESSES	56
C.2 EVALUATED FGD TECHNOLOGIES.....	57
C.3 EVALUATED NO _x TECHNOLOGIES.....	66
APPENDIX D.....	68
APPENDIX E	71
E.1 LIMESTONE FORCED OXIDATION	71
E.2 SPRAY DRYER ABSORBER SYSTEM.....	74
E.3 CIRCULATING DRY SCRUBBER	76
E.4 DRY SORBENT INJECTION SYSTEM (DSI)	78
E.5 MULTI-POLLUTANT FLUE GAS DESULFURIZATION (ReACT).....	79
APPENDIX F	82
F.1 MERCURY SPECIATION	82
F.2 ACTIVATED CARBON INJECTION.....	82
F.3 SORBENTS.....	83
F.4 COAL PRE-TREATMENT/WET FGD CO-BENEFIT	84
F.5 CHEMICAL ADDITIVES TO CONTROL MERCURY RE-EMISSION FROM FGD SLURRY.....	84
APPENDIX G	86
G.1 SELECTIVE CATALYTIC REDUCTION	86
G.2 SELECTIVE NON-CATALYTIC REDUCTION	87

1.0 PROJECT DESCRIPTION

Wisconsin Public Service Corporation (WPS) submits this application to the Public Service Commission of Wisconsin (PSCW) for a Certificate of Authority (CA) under Wisconsin Statutes Section 196.49 and Wisconsin Administrative Code Chapter PSC 112 to install a multi-pollutant control technology commercially known as ReACT™ (ReACT) on Weston Unit 3 at the Weston Generating Station. The purpose of the ReACT system is to reduce sulfur dioxide (SO₂), Nitrogen Oxides (NO_x), mercury, and other air pollutant emissions from the unit.

The ReACT system at Weston Unit 3 was selected because it meets the following overall objectives:

- Reduce SO₂, NO_x and mercury emissions from Weston Unit 3 in order to comply with current, pending and future environmental regulations including the federal Cross State Air Pollution Rule (CSAPR) (or a similar replacement regulation) and federal and state mercury rules.
- Achieve sufficient SO₂ and NO_x reductions to meet the emission limitations likely to result from a resolution of the U.S. Environmental Protection Agency's (EPA) Notice of Violation (NOV) alleging violations of New Source Review (NSR) and Prevention of Significant Deterioration (PSD) regulations at the Weston Generating Station.¹
- Allow beneficial use of by-products from emission control systems to the extent practicable.
- Constitute an economic alternative to replacement of Weston Unit 3.
- Minimize increased emissions of any other regulated pollutants.
- Minimize the adverse impact on Weston Unit 3 balance of plant (BOP) operations during construction.
- Maintain access to existing equipment for maintenance.
- Provide long-term reliability, operability, and maintainability for the ReACT equipment.

The Weston Generating Station is located on a 345-acre parcel of WPS-owned land in the Villages of Kronenwetter and Rothschild in Marathon County, approximately 7 miles south of Wausau (Figure 1-1). The site currently has four coal-fired generating units, two gas/oil-fired combustion turbine generators, and auxiliary equipment such as substations and fuel supply systems.

¹¹¹ As discussed in Section 3.1.H, WPS has not reached agreement with EPA on resolution of the NOV and their negotiations are the subject of a confidentiality agreement. WPS's analysis of the potential outcome of the negotiations included consideration of information regarding settlements of other EPA NOVs alleging NSR/PSD violations by other utilities, as well as information regarding the capabilities of various emission control technologies.

PUBLIC VERSION

Weston Unit 3 is WPS's second newest and second largest coal-fired electric generating facility. The unit went into service in 1981 and has a heat rating of 3423.48 mm Btu/hr and burns primarily Powder River Basin (PRB) coal.

ReACT is an advanced regenerative activated coke (AC) technology that provides for control of SO₂ with a coincident reduction of NO_x, mercury, and other pollutants. The system also produces commercial grade sulfuric acid, a commercially marketable by-product.

The ReACT system's total capital cost estimate, including AFUDC, is \$288 million. The system will incorporate the following major components:

- ReACT process adsorption equipment
- ReACT process thermal regeneration equipment
- AC material handling and preparation facilities
- Reagent (ammonia) material handling and preparation facilities
- Sulfuric Acid Plant with pre and post treatment systems
- Sulfuric Acid bulk storage and offloading systems
- Nitrogen Generation System including cryogenic storage
- New Induced Draft (ID) fans and associated ductwork
- Other balance of plant (BOP) modifications, as required

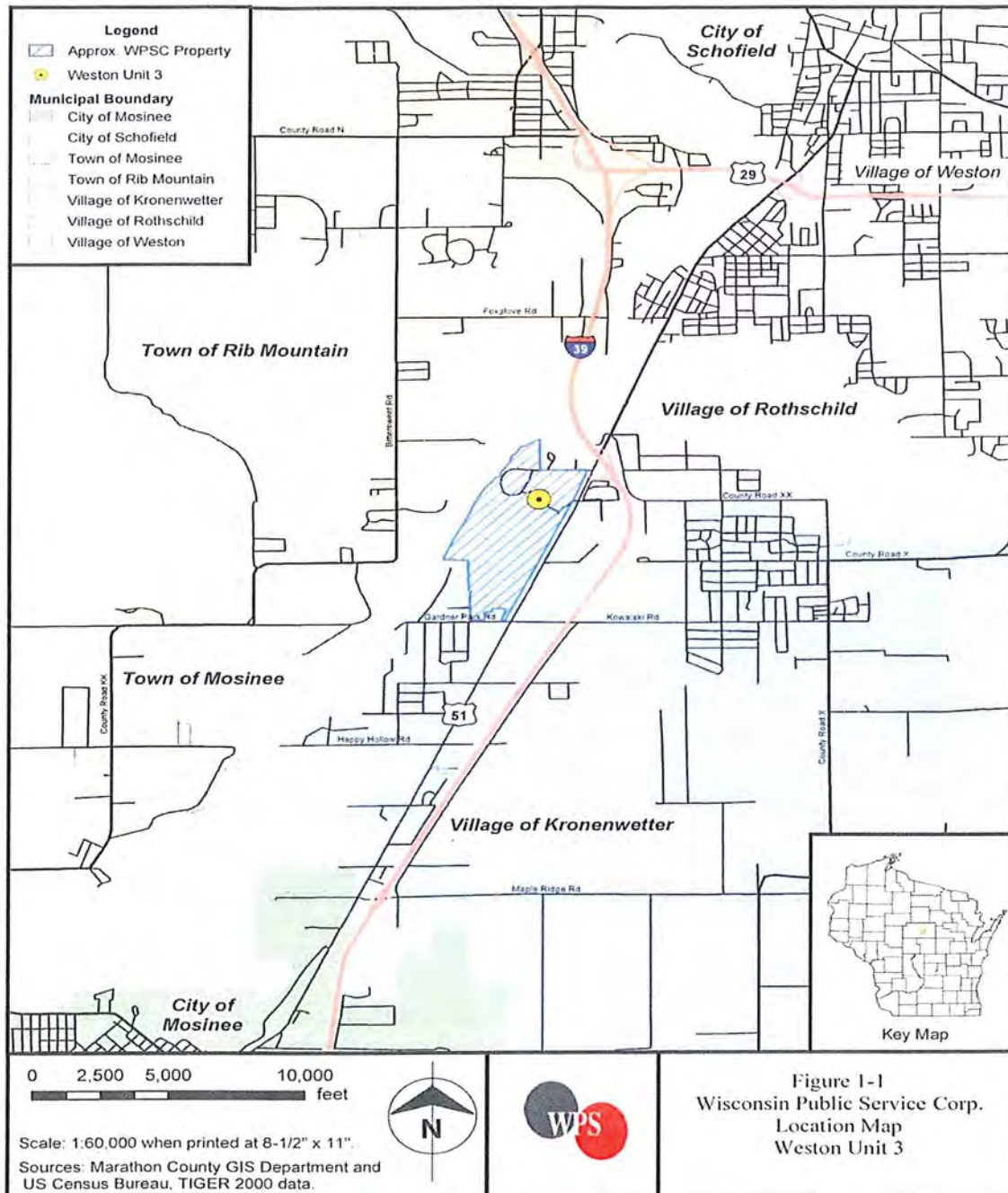
Major construction is currently anticipated to occur to the south and west of the existing Weston Unit 3 fabric filter. The ReACT facilities will be located in open vacant areas to facilitate constructability and reduce relocation and demolition requirements. A preliminary general site arrangement drawing for the ReACT system is provided in **Appendix A**.

The fabric filters were installed on Weston Unit 3 in 2000, as part of a separate air pollution control project, and will continue in service to support the ReACT system.

Low NO_x burners and a separated over fire air system were installed for NO_x control in 2009. These systems will continue in service to support the ReACT system.

A powdered activated carbon injection system (ACI) was installed on Weston Unit 3 in late 2009 for mercury emissions control. This system is expected to be available to provide operational flexibility to meet current and future emissions control requirements.

Figure 1-1



Issued: December 1, 2006

1.1 SELECTED TECHNOLOGY

The technology that best meets the objectives listed in **Section 1.0** is a ReACT system.

The ReACT process operates in three stages: adsorption, regeneration, and by-product recovery.

The AC material provides a large surface area that is adsorptive, catalytic, and reactive for adsorption of SO₂, mercury and other gas species and for the reduction of NO_x.

After the adsorption step, the AC is thermally regenerated for return to the adsorbers. The AC adsorbent material is in pellet form which has mechanical strength such that the material can be subjected to repeated regeneration cycles.

The by-product of the regeneration process is a sulfur-rich gas (SRG) that will be converted into a marketable grade of sulfuric acid. This process results in the beneficial re-use of the sulfur compounds removed from the flue gas stream.

1.1.1 Dry Moving Bed Adsorption Process

The adsorber is a device that provides highly efficient contact between the flue gas to be treated and the AC. Flue gas flows at low velocity through a moving bed of AC pellets which contains a very large surface area of high-capacity sorbent material.

The main focus of the technology is the removal of SO₂ by adsorption onto the AC surface. Both SO₂ and acid gases are controlled. The efficiency of the adsorption of SO₂ and other acid gases are improved in the presence of ammonia, which is injected into the flue gas before it enters the adsorber vessel. Within the AC, the adsorbed SO₂ and other acid gases are in the form of sulfuric acid and ammonium salts.

The AC also provides highly efficient adsorptive capture of mercury, and provides a reduction of NO_x via both catalytic and non-catalytic mechanisms. The efficiency of these mechanisms is improved by the presence of ammonia in the incoming flue gas stream and the creation of surface functional groups in regenerated AC.

The adsorber vessel is comprised of a number of individual moving bed devices that operate in parallel as a single pass adsorber. Each moving bed receives a feed of regenerated AC at the top and the AC flows (by gravity) downward at a rate controlled by a roll feeder located at the bottom of each bed.

Flue gas passes cross-wise through the bed at low velocity and leaves the adsorber with very little change in temperature or moisture content. The cleaned exhaust gases are then directed by ductwork to the stack and released.

The AC discharged from the adsorber vessel is mechanically conveyed to the regeneration vessel.

1.1.2. Regeneration

The pollutants that have adsorbed to the AC pellets are removed by a thermal regeneration process. The AC pellets are heated to temperatures that assure near complete desorption of the captured pollutants and produce a SRG that is the feedstock material for the acid plant.

The regenerator vessel is a vertical three stage indirect heat exchanger with an AC feed section at the top, followed by an upper preheat section and upper isothermal zone (at about 450°F) from which the SRG is extracted, a heating section and lower isothermal zone at about 850°F to assure near-complete desorption, and a lower cooling and discharge section.

The AC pellets flow by gravity from the top of the regenerator on the tube side of the indirect heat exchanger. The AC pellets enter and leave the regenerator through nitrogen-purged lock hoppers. Nitrogen gas is also introduced below the cooling section of the regenerator as a sweep gas that provides upward flow of desorbed gases to the SRG extraction point.

The heat exchange fluid for the regenerator is air in the cooling section and flue gas from a natural gas fired furnace in the heater and pre-heater sections. The cooling air and combustion gases flow on the shell side of the heat exchanger and do not come into direct contact with the AC pellets.

Following the heat exchanged fluid, ambient air is delivered to the cooling section in order to reduce the temperature of the newly regenerated AC pellets to <300°F. The ambient air picks up heat from the pellets and leaves the cooling section at about 350°F. This heated air is then used as the primary combustion air for the natural gas furnace and is also used as dilution air for ammonia injection upstream of the adsorbers and regenerator outlet. A quantity of heated air that is not required for combustion or ammonia dilution is vented to the atmosphere.

The natural gas fired furnace provides the heat needed to increase the AC pellet temperature to 850°F. The combustion exhaust gases (approximately 1000°F) go from the furnace directly to the heating section.

A portion of the combustion gases from the heating section (now at about 600°F) are routed to the preheat section. The exit gases from the preheat section are recombined with the balance of the exit gases from the heater section and are re-circulated (at about 550°F) to the natural gas furnace in order to maintain the natural gas furnace exhaust at 1000°F. Excess 550°F gases not needed at the furnace are purged from the system and are sent back to the inlet of the adsorber.

The mercury captured in the adsorbers is also thermally desorbed at 850°F. Mercury vapors flow with the other desorbed gases upwards in the heater section. The temperature profile at the top of the heater section and in the upper isothermal zone allows for recapture of the upward flowing mercury by the cooler downward flowing AC pellets. The adsorption capacity for mercury in this specific zone of the regenerator is high enough for the mercury to be completely contained in this moderate temperature zone for an extended period. The mercury-contaminated AC pellets are periodically removed from the regenerator vessel during a scheduled outage. Based on the expected concentration of mercury in the flue gas, it is anticipated that approximately 70 tons of mercury-contaminated AC will be removed every of 18 to 36 months of operation.

The adsorbed SO_2 is held on the AC pellets as sulfuric acid, ammonium sulfate, and ammonium bisulfate. During the thermal regeneration process, these compounds participate in a series of reactions with the AC and decompose to form a SRG mixture that is comprised of N_2 , SO_2 , CO_2 and H_2O . This SRG mixture together with the sweep nitrogen gas is transferred via a duct to the by-product recovery system (acid plant).

The NO_x removal in the system occurs within the adsorber and regenerator vessels as reduction of NO_x compounds to N_2 .

After the AC pellets are thermally regenerated in the heating section and the desorbed gases are swept away by the nitrogen sweep, the pellets enter the cooling section of the vessel where the AC temperature is reduced to 300°F or lower.

The cooled regenerated pellets are discharged through a nitrogen-purged lock hopper, and are then passed over a vibratory screen classifier for separation of undersized materials including flue gas particulates which had been captured by the AC. The separation of undersized AC particles is an adsorber pressure drop consideration as it allows the overall size distribution of the AC in the adsorber to be maintained. The undersized material is mixed with coal and used as a secondary fuel in the boiler. Fresh make-up AC is added to the system to replace the undersized material.

The regenerated AC pellets are returned to the adsorber vessel by a mechanical conveying system.

1.1.3 Sulfuric Acid and Other By-Product Recovery

The SRG from the ReACT regenerator is transferred via duct work to the by-product recovery system. The by-product recovery system uses a commercial acid plant technology to convert the SO_2 in the SRG stream to a marketable grade of sulfuric acid by-product. The system will have a design capacity of approximately 77 tons/day and be located west of Weston Unit 3's fabric filter.

The conversion process can be divided into the following four steps:

1. Cooling and purification of the SRG
2. Dilution and drying of the SRG
3. Conversion of SO_2 to SO_3
4. Absorption of SO_3 in sulfuric acid and water

Cooling and Purification

The SRG contains impurities that must be removed prior to the conversion of SO_2 to SO_3 . These impurities include ash, halides, water vapor and other constituents of the flue gas stream that are captured in the ReACT system and driven off in the regenerator. Initial cooling and removal of impurities in the SRG are accomplished by passing the SRG through a scrubber.

The scrubber re-circulates a weak sulfuric acid solution along with a compound to scrub and cool the SRG. The weak acid is cooled using heat exchangers and cooling water supplied from Weston Unit 3's cooling tower. Weston Unit 3's cooling tower has the capacity to supply cooling to the by-product recovery system with minimal impact on the unit. The additional cooling

tower duty can impact the unit at high loads during the summer months. It is estimated that the average impact on the unit during these months will be a heat rate penalty of approximately 10 Btu/KWh, when the unit is running at high loads. The efficiency loss will be higher on hotter days and result in a small decrease of unit capacity.

Condensed water vapor and impurities collected in the scrubber are removed by bleeding a 2–14 gallons per minute (gpm) effluent stream from the re-circulated weak acid. At this time, it is expected that the effluent stream will first be neutralized using a caustic solution and then be pumped into a spray grid upstream of Weston Unit 3's fabric filter, where it will be vaporized by the incoming flue gas. This system will also include a storage tank for simple neutralization and to allow flexibility in injection rates to the fabric filter based upon unit load. The fabric filter will then collect the solid impurities from the effluent stream. It should be noted, that WPS is continuing to investigate other options for the effluent stream through the detailed engineering process.

Dilution and Drying

After purification, the SRG is diluted with a filtered air to supply the oxygen necessary for the catalytic oxidation of SO_2 to SO_3 . The diluted SRG is then dried in a drying tower using a counter current stream of sulfuric acid to remove the water vapor from the SRG. After drying, the dilute SRG is compressed and forced through the remainder of the plant using a blower.

Conversion

The conversion of SO_2 to SO_3 takes place in a multiple pass converter using a vanadium catalyst. The oxidation of SO_2 to SO_3 is exothermic allowing for the excess heat of reaction to be used to heat the incoming SRG via heat exchangers, to maximize the conversion efficiency while also cooling the partially converted gas stream between converter passes. During start-up and low load operation, an inline heater will be used to heat the incoming SRG. Both electric and natural gas heaters are being considered at this time, with combustion gases of the latter continuing through the process to the inlet of the ReACT system.

Current commercial acid plant technologies using multiple pass converters are able to achieve 97% conversion of SO_2 to SO_3 . The vanadium catalyst has a typical useful life of approximately 7 – 10 years, at which time it will need to be replaced. The used catalyst is expected to be sent back to the manufacturer for recycling and regeneration.

Absorption

The converted SO_3 gas is then passed through an absorbing tower in which it is absorbed in a re-circulated sulfuric acid and water solution and converted to sulfuric acid. The sulfuric acid is cooled with heat exchangers using cooling water from Weston Unit 3's cooling tower.

Effluent gas along with any unconverted SO_2 from the converter passes through the absorber and is piped back to the inlet of the ReACT for SO_2 recapture. The sulfuric acid product from the absorber is pumped to a storage tank with an expected 10-15-day capacity. From the storage tank, the sulfuric acid is pumped to a sulfuric acid truck loading facility or rail loading facility for transport to a distributor or customer. Transportation of the sulfuric acid product will require an average of 2 trucks per day, or one rail car every other day under normal operating conditions.

The by-product system produces a fine mist of sulfuric acid in the effluent gas discharge from the SO₃ absorber/condenser that is addressed differently depending on the vendor technology chosen in the detail design phase of the project. The methods used to minimize the fine mist include the use of a proprietary wet mist eliminator or candle-type filters.

1.2 WESTON UNIT 3 CONSTRUCTABILITY SUMMARY FOR REACT SYSTEMS

Based on site reviews and assessments done by engineering consultants, a ReACT system for SO₂ control and reduction of other emissions is feasible for installation and operation on Weston Unit 3. Retrofit work should be completed with minimal impact to existing operations due to the open space available for construction and the installation of new equipment. The following will be completed prior to finalizing the engineering plan and construction approach:

- Layouts of specific equipment for the selected technology
- ReACT vendor equipment
- Ductwork
- ID Fans
- By-product and reagent handling systems
- Other balance of plant equipment
- Underground interferences will have to be investigated to determine the best way to traverse existing roadways and to evaluate foundation designs for all new equipment

The site layout and construction approach will be finalized during detailed engineering.

1.3 CONSTRUCTION APPROACH

The following is a high-level overview of the construction approach for the project, which focuses on minimizing the required outage time for Unit 3 while reducing the impact of construction activities on facility operations. WPS plans to minimize plant down-time by coordinating the tie-in of equipment with regularly scheduled maintenance outage periods.

1.3.1 Electrical System Tie-ins

The electrical power source for the new equipment will be fed from the existing plant distribution system. Major components of the electrical system include feeder cables from existing switchgear, auxiliary transformers, motor control centers, substations, and system grounding. New switchgear will be necessary where additional ReACT motors exceed the capacity of the existing system. New auxiliary transformers may be required to handle the added electrical loads. These requirements will be further developed as detailed design progresses.

1.3.2 Instrumentation and Controls Modifications

New instrumentation and controls (I&C) are required for the ReACT system operations. The additional instrumentation and controls will be integrated into the plant's existing distributed control system (DCS). The primary control functions will be automated process control, system monitoring, and operational alarms. New controllers and operator and engineering workstations will be provided along with the new system instrumentation and controls equipment. The I&C system would be finalized during detailed design.

1.3.3 Fan and Boiler Modifications

New ID fans and motors, AC unloading and processing equipment, AC fines handling equipment, and blowers will be included as part of the BOP equipment package. The equipment details will be finalized in the detailed engineering phase, after equipment vendors have been selected and the final operating conditions for equipment are determined.

The flue gas path pressure transient changes on all existing boiler and flue gas path components due to the ReACT system will be analyzed. The current cost estimate assumes that all existing components will be able to handle the post-ReACT transient pressure conditions without major structural modifications.

1.3.4 ReACT System

The adsorber vessels and regeneration equipment will be fabricated off-site and shipped in large modules to the project site. Fabrication philosophy will be finalized during detailed design, and will emphasize minimizing on-site fabrication.

1.3.5 Ductwork

The rectangular steel plate ductwork, including duct plate, stiffeners, and ductwork support structure will be shipped to the site for installation. To minimize on-site fabrication, some ductwork may be pre-assembled off-site prior to shipment.

1.3.6 Civil Work

Structures, components, and foundations will be designed so that their strength equals or exceeds the effects of factored load combinations. A Weston site geotechnical report was used to define foundation requirements. Buildings will enclose and protect the equipment as required. Foundations for the primary equipment will be the first structures constructed upon start of construction.

1.3.7 Demolition

A majority of the new equipment, including the ReACT adsorber, regenerator, ID fans, and AC handling equipment, will be located in open areas around the existing Weston 3 fabric filter. Accordingly, the project will not require significant demolition or relocation of existing equipment or facilities. Area preparation will require ground levelling and removal of the solids pile extraction equipment. This work will need to be completed before the foundations for the major equipment are constructed. (See Section 5 for further detail on demolition plans.)

1.4 MILESTONE SCHEDULE

The following project milestone dates submitted at this time are based upon execution of the necessary procurement, manufacturing and construction activities.

Milestone	Start	Complete
Regulatory Approvals (PSCW)	May 2012	January 2013
Award System Furnish & Erect Contract		February 2013
Award Balance of Plant Design Contract		February 2013
Detailed Engineering and Design	February 2013	Fourth Quarter 2014
Material & Fabrication Delivery	Third Quarter 2013	Third Quarter 2015
System & BOP Construction	Second Quarter 2013	Second Quarter 2016
System Commissioning	Second Quarter 2016	Fourth Quarter 2016
Commercial Operation		Fourth Quarter 2016

2.0 COST AND FINANCING

WPS performed extensive due diligence in order to develop the economic basis for the ReACT system and alternative emission control technologies. This effort included indicative soliciting and analyzing proposals from suppliers, BOP cost estimates, and WPS owner's costs. The BOP and WPS costs were developed from previous site specific studies performed for the proposed Weston Unit 3 Flue Gas Desulfurization (FGD) project and updated. The indicative proposals combined with the BOP and WPS owner's costs formed the total project capital cost estimate or Total Installed Cost (TIC). The WPS owner's cost included costs for project management and oversight, licensing and permitting support, and other miscellaneous costs to support project development. The TIC was used in the economic analysis and is described in **Section 3.0** using rate-based financing. The coal analyses provided by the WPS Fuels Department represented expected fuels and served as the basis for the combustion calculations. The flue gas composition and flow rate then became the basis for all equipment sizing and operating cost calculations.

The due diligence effort included a reasonable level of preliminary engineering and was used as the estimating process to derive the capital, operation and maintenance (O&M), and life cycle costs for the FGD technology alternatives considered in the technology selection analysis. This effort consisted of a thorough review of the technology alternatives, indicative pricing of process equipment based on site and unit specific data, Weston Unit 3 walk downs, constructability reviews, preliminary risk analysis, and in specific instances, field visits to evaluate existing operating facilities.

2.1 ESTIMATED CAPITAL COST AND CASHFLOW

Table 2-1 contains the estimated capital cost cash flows in year of occurrence dollars on a calendar year basis assuming an in-service date of Fourth Quarter 2016 for the Weston Unit 3 ReACT. The capital cost cash flows are developed from the overnight capital cost estimate and escalated at 2.2 percent per year for the year of occurrence numbers. **Table 2-1** presents the distribution of the capital cost cash flows, excluding Allowance for Funds Used During Construction (AFUDC).

The current estimate for AFUDC, based on the above project cost estimate and cash flow, is \$38M. The total project capitalized cost estimate for the ReACT system, including AFUDC, is \$288M.

PUBLIC VERSION

The capital cost estimate is categorized by major system and listed in **Table 2-2**.

Table 2-1
Annual Cash Flow
Year of Occurrence Dollars Excluding AFUDC

FGD – Fourth Quarter 2016 In-Service*		
Year	Capital Expenditures (Millions)	O&M Expenditures (Millions)
2012	\$2.2	
2013	\$46.3	\$0.9
2014	\$98.7	\$1.1
2015	\$77.5	
2016	\$23.3	
Total	\$248.0	\$2.0

*Includes Capital Costs, Owner's Cost, and O&M Expenses During Construction;
 Totals are the Sum of Escalated Year of Occurrence Dollars

Table 2-2
Estimated Capital Cost
Year of Occurrence Dollars Excluding AFUDC

[illegible]

2.2 FINANCING MECHANISM

The Weston Unit 3 ReACT system is proposed as a rate-based project. WPS proposes to finance this project using the traditional utility capital structure. In accordance with Finding of Fact #39 of the Commission's January 11, 2007 Final Order in Docket 6690-UR-118, the cost of capital during construction will be capitalized using 100 percent AFUDC. Once this project is completed, all of the investment including AFUDC will be placed in WPS's rate base and will be subject to traditional ratemaking.

3.0 NEED AND ALTERNATIVE OPTIONS ANALYSIS

The ReACT project is needed for Weston Unit 3 to comply with pending and future regulation of air emissions, including CSAPR, federal and state mercury rules, and the likely emission limitations that would result from a resolution of the EPA NOV. The economic analysis described in this section assesses two emission control technology options (FGD/SCR and ReACT) as well as replacement of Weston Unit 3. All three alternatives result in significant SO₂ and NO_x emission reductions that would be needed by WPS to comply with the anticipated SO₂ and NO_x emission limits. All three alternatives also ensure compliance with federal and state mercury rules.

3.1 PLANNING FOR AIR EMISSIONS REGULATORY REQUIREMENTS

WPS's emission compliance program continually evaluates the full range of current, pending and future environmental regulations to determine the need for investment in emission controls and alternative compliance strategies. Planning for a reliable and cost effective supply of electric capacity and energy has become increasingly difficult for utilities, with the uncertainties centered around the timing and level of stringency of new air regulations and the power markets' reaction to them. WPS has sought to reduce the uncertainties for its system by increasing the flexibility of its coal-fired units to respond to changes in MISO market pricing, and identifying and developing supply alternatives that contribute to fuel diversity. But WPS's proactive planning cannot eliminate all uncertainty, and WPS and its customers cannot afford to wait until clear choices emerge. WPS must continuously assess the impact of existing and proposed air regulations on its portfolio of generation resources – all in the context of trends in load growth (or decline), fuel prices, construction costs and the multitude of other factors that affect the company's cost of service – and act when necessary to maintain reliability, control cost and preserve a reasonable degree of optionality.

There are several regulatory drivers of a system plan that includes the installation of a multi-pollutant control technology on Weston Unit 3, which is the subject of this CA application. These drivers include EPA's continued effort to promulgate an effective interstate air rule regulating SO₂ and NO_x emissions, DNR's promulgation of stringent mercury rules, and the potential resolution of EPA's pending enforcement action against WPS for alleged NSR/PSD violations at Weston Unit 3. This section discusses these issues and their relationship to WPS's current supply plan and this CA application.

A. Clean Air Interstate Rule (CAIR) and Cross State Air Pollution Rule (CSAPR)

In 2005, the EPA issued the Clean Air Interstate Rule (CAIR) which required reductions of SO₂ and NO_x emissions from existing and new EGUs with capacities exceeding 25 MW. 70 Fed. Reg. 25,162. This rule capped SO₂ and NO_x emissions in 28 states in the eastern U.S., including Wisconsin. When fully implemented, CAIR was expected to reduce emissions in these states by over 60% and 70% for NO_x and SO₂, respectively, from 2003 levels. CAIR provided states the option of using a market-based cap-and-trade approach to achieve the required reductions through a two-phase compliance timeline. The first phase reductions of NO_x and SO₂ were required by 2009 and 2010, respectively. In addition, there is an ozone season cap that further restricts NO_x emissions within applicable areas from May 1 through September 30 of each year. Second-phase reductions for both NO_x and SO₂ emissions must be implemented by 2015.

On July 11, 2008, the United States Court of Appeals for the District of Columbia Circuit Court found that CAIR was fundamentally flawed, and vacated the rule in its entirety. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). On December 23, 2008, the Court modified the remedy and remanded CAIR, without vacatur, to the EPA to modify the rule consistent with the court's July 11, 2008 decision, thereby preserving CAIR in its entirety.

In response to the court decision directing EPA to modify CAIR consistent with the July 11, 2008 decision, EPA proposed the CAIR replacement rule, known as the Clean Air Transport Rule (CATR) on August 2, 2010. On July 6, 2011 EPA finalized CATR and changed its name to CSAPR. 76 Fed. Reg. 48208.

CSAPR requires states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle (PM_{2.5}) pollution in other states. At the time the rule was finalized, it was scheduled to take effect on January 1, 2012. However, several parties including WPS, challenged the rule and on December 30, 2011 the United States Court of Appeals for the D.C. Circuit issued a stay of CSAPR pending judicial review. *EME Homer City Generation, L.P., et al. v. EPA*, No. 11-1302 (D.C. Cir. Dec. 30, 2011) (order granting requested stay). Oral arguments were made in April 2012 with a court decision expected mid to late 2012.

If CSAPR is upheld, significant NO_x and SO₂ reductions will be required across the WPS system compared to historical emissions. Under CSAPR, each of the affected states (including Wisconsin) has a state allowance budget, which ratchets down in 2014 for SO₂ for Wisconsin. CSAPR allows some limited interstate allowance trading, but would include "assurance provisions" which generally provide that, in a single year, a state's emissions must not exceed the state's budget plus a variability limit. When a state exceeds its budget plus the variability limit, any owner whose emissions exceeded its share of the state budget and variability limit would be required to surrender additional allowances as a penalty. The assurance provisions do not become effective until January 1, 2014.

As a result of the installation of low NO_x burners and/or overfire air at WPS's Pulliam and Weston units, compliance with the overall NO_x allocations for the WPS system does not require operating restrictions as significant as does compliance with the WPS SO₂ allowance allocations. In other words, unit operation that ensures SO₂ emissions are below the allocation level will also ensure that NO_x emissions are below allocation levels. The table below shows WPS's historic SO₂ emissions as well as the allowance allocations (as adjusted by EPA on February 7, 2012) and the significant shortfall of allowances for the WPS system compared to the historic emissions.

EPA PROPOSED CSAPR ALLOCATIONS				HISTORIC EMISSIONS			
	Unit Number	SO ₂ Allocation 2012 (tons)	SO ₂ Allocation 2014 (tons)	Sulfur Dioxide (tons)			
				2007	2008	2009	2010
Columbia*	1 & 2	4132	2460	8174	8419	7822	8694
Edgewater*	4	1126	671	2008	1921	1471	1738
De Pere Energy Center	1	1	1	1	0	0	0
Pulliam	all	4132	2460	10448	8446	4386	5517
West Marinette	all	1	1	0	1	0	0
Weston	1 & 2	1746	1040	2983	2852	2060	2601
Weston	3	4380	2608	6125	7338	5912	7216
Weston*	4	784	784	0	226	680	789
Weston	32A & 32B	0	0	0	0	0	0
Totals		16302	10025	29739	29203	22331	26555
Allowance Shortfall vs. 2012 Allocation				13437	12901	6029	10253
Allowance Shortfall vs. 2014 Allocation				19714	19178	12306	16530

* Represents portion of plant owned by WPS.

WPS's SO₂ emissions were 29,203 in 2008, 22,331 in 2009, and 26,555 in 2010, and its 2014 allocation under CSAPR will be 10,025. Although scrubbers for the removal of SO₂ are planned for installation at the jointly owned Columbia Units 1 and 2 prior to the end of 2014, reductions achieved there will not be adequate to allow WPS to operate its remaining generating units at historic levels under CSAPR. To maintain the operation of its fleet at levels similar to those in 2008-2010, WPS will need to either install additional SO₂ controls on certain units and/or rely on the SO₂ allowance market. Given the trading limitations in CSAPR, relying solely on the allowance market would involve excessive risk with respect to allowance supply and cost. Even if allowances are available in the quantities required, the assurance provisions in CSAPR would likely preclude WPS from being able to operate its units at levels similar to 2008-2010 unless it installs additional SO₂ controls on Weston Unit 3.

Of all of the units in WPS's fleet, Weston Unit 3 is the first choice to install additional controls. Pulliam Units 5-8 and Weston 1&2 are older, smaller and less efficient units than Weston 3. Installation of the ReACT technology at Weston 3 would free up annual SO₂, annual NO_x, and ozone season NO_x allowances that WPS could use for compliance at other units. The project would also help Wisconsin stay below its statewide CSAPR assurance provision cap.

If CSAPR is invalidated by the D.C. Circuit Court, EPA will be required to develop a new CAIR replacement rule to address sources that are significant contributors to downwind nonattainment problems in other states. There is no draft rule available in the event CSAPR is invalidated. WPS's current planning assumption is that emission reductions comparable to

CSAPR will be required when EPA meets its obligation under the Clean Air Act (CAA) to address the sources that contribute to downwind nonattainment.

B. Mercury and Air Toxics Standard (MATS)

On December 21, 2011, EPA released the details of the final Electric Generating Unit Maximum Achievable Control Technology rule (MATS) for the control of hazardous air pollutants (HAPs). Only minor changes were made between the draft rule (published March 2011) and the final rule. Mercury emissions are limited to 1.2 lb/TBtu on a 30-day rolling average basis. A 90-day rolling average may be used, but if utilized the limit is reduced to 1.0 lb/TBtu. Typically, to control mercury emissions various sorbents such as activated carbon are injected into the flue gas to react with mercury for collection in a fabric filter or electrostatic precipitator. Particulate matter (PM) emissions are also limited under the rule as a surrogate for the non-mercury metals. PM emissions are limited to 0.03 lb/mmBtu. Hydrochloric acid emissions must be controlled for compliance with the acid gas limits. For uncontrolled units (no Dry Sorbent Injection (DSI) or FGD), HCl emissions are dependent on the chlorine content of the fuel burned. Any plant equipped with an FGD or DSI may demonstrate compliance with the acid gas limit by use of an SO₂ Continuous Emission Monitor (CEM). SO₂ emissions are limited to 0.20 lb/mmBtu (30-day rolling average) to demonstrate compliance with acid gas limitations.

The final rule continues to allow the use of facility averaging across multiple boilers to demonstrate compliance with emission limitations. While WPS believes that the carbon injection system already installed on Weston Unit 3 would ensure compliance with the MATS rule (as well as Wisconsin's mercury rule discussed below), installation of the proposed ReACT system is expected to reduce mercury emissions below the level required by the two rules. The existing ACI system is expected to be available to provide operational flexibility to meet current and future emissions control requirements.. The additional compliance margin for mercury will assist an uncontrolled or partially controlled unit at the same site to achieve compliance on a combined or average basis.

C. Wisconsin Mercury Rule

In December 2008, WDNR promulgated revisions to NR 446, the Wisconsin state mercury rule. NR 446 required utilities to reduce mercury emissions by 40% by 2010. Further, coal-fired EGUs greater than 150 MW (like Weston Unit 3) must reduce mercury emissions by 90% or limit outlet concentrations to 0.0080 pounds per GWh of energy generated by 2015. The rule does not require a specific method or technology for the reductions, and therefore allows affected utilities to select control options that are both cost-effective and suited to the utility's particular needs. A utility may achieve compliance with the 2015 requirements either on a unit-by-unit basis, where each EGU meets the mercury emission limit, or by unit averaging across the combined system. The proposed ReACT technology will help WPS meet the NR 446 requirements by reducing mercury emissions from Weston Unit 3.

D. EPA NSR/PSD Settlements

EPA has alleged that many utility sources have made changes to existing facilities without applying for and obtaining pre-construction permits. In EPA's view, the lack of NSR/PSD permitting indicates that many stationary sources are emitting air pollutants in excess of these CAA requirements. EPA has determined that given the scope of the reductions to be obtained,

addressing NSR/PSD questions as a national priority should result in substantial human health and environmental benefits. EPA selected four industrial sectors, including coal-fired power plants, for investigation based on their belief that there was a high probability that past modifications had occurred that did not first obtain required NSR/PSD permits. The Office of Enforcement and Compliance Assurance (OECA) uses various tools to investigate potential violations in the selected sector areas. If EPA concludes that a facility has made modifications without obtaining an NSR/PSD permit a Notice of Violation (NOV) is issued to the facility/company. The owner of the facility has the option to go to court to challenge the EPA allegations or enter into a negotiation leading to a Consent Agreement resolving the issue.

EPA has issued a NOV to WPS alleging that modifications were made at Weston Unit 3 and other coal-fired facilities without first obtaining required NSR/PSD permits. As part of any Consent Agreement resolving such an NOV, EPA will require emission reductions from the coal-fired generating facilities alleged to have made the modifications that triggered the requirement for obtaining a permit. These reductions can be achieved either by the installation of pollution control equipment or the replacement of individual units.

Although WPS has not reached a settlement with EPA, and settlement is not guaranteed, for the purpose of this CA application, WPS assumed, based upon other EPA NOV settlements, that resolution of the EPA NOV would require SO₂ and NO_x emission reductions on Weston Unit 3. To maintain schedule requirements, WPS is filing this CA Application now using these assumed emission reductions.

If, as expected, a resolution of the EPA NOV is achieved, WPS will update this application to take into account the terms and conditions of the settlement.

E. Summary

Significantly lower emissions of SO₂ and NO_x from Weston Unit 3 are necessary in response to the following regulatory requirements:

- The reinstatement of CSAPR, or a similarly stringent transport rule replacement,
- The expected resolution of the EPA NOV
- Weston Unit 3 must achieve and maintain compliance with federal and state mercury rules.

The installation of the proposed ReACT system at the unit will ensure compliance with these current and anticipated emission regulations. SO₂, NO_x and Hg emission reductions achieved by this technology should be adequate to achieve compliance with the most stringent unit-specific requirements predicted to be applicable over the assumed remaining life of this unit in this study.

Further, the proposed ReACT system mitigates market risk associated with relying on SO₂ and NO_x allowances to achieve ongoing compliance.

3.2 EMISSION COMPLIANCE PLANNING PROCESS

The following is an outline of WPS's emission compliance planning process:

- Evaluate impacts of proposed or pending new environmental regulation on current plans for the WPS electric resource portfolio.
- Determine if emission reductions are needed and the options available for reduction.
- Identify and develop technical/cost data associated with various environmental control options.
- Screen the options to a subset of candidate control options.
- Develop alternative plans from options subject to reliability requirements for detailed dispatch (including environmental dispatch) simulation and calculation of system attributes and revenue requirements.
- Perform simulations and identify plan attributes such as, emissions, fuel usage, reliance on purchase power, and present value revenue requirements.
- Select set of plans on basis of emission compliance and present value revenue requirement adjusted for risk (fuel, purchase power, allowance price and volume risk).
- Determine trigger points for the various options (environmental control retrofits, change in unit operation, allowance buy/sell, new unit additions) that make up the subset of plans.
- Monitor key planning parameters, and upcoming changes in regulations.
- Restart the process at steps appropriate to change in study parameters.
- Initiate detailed analysis of major design aspects for a given option once the trigger point is reached.
- Perform detailed planning evaluations needed to support need and alternative analysis in thePSCW application.

3.3 ECONOMIC ANALYSIS OF ALTERNATIVES

EPA promulgated CSAPR in July 2011. Compliance with this rule would require WPS to achieve significant reductions in SO₂, annual NO_x and ozone season NO_x from its coal-fired electric generation fleet and/or purchase additional allowances beyond its allocation. The rule has two phases: Phase 1 begins January 2012 (currently stayed pending court action) and Phase 2 is currently scheduled to begin January 2014. In addition, WPS has received a NOV from EPA alleging violations of NSR/PSD regulations at Weston Unit 3 and other facilities.

The economic analysis of the proposed ReACT project evaluates alternative compliance plans that assure Weston Unit 3's compliance with the reductions in SO₂ and NO_x required by Phase 2 of CSAPR as well as the likely reductions required by a resolution of the EPA NOV. The primary focus of this study is 2014 and beyond with the focus being on compliance options for Weston Unit 3. See **Appendix B** for a complete description of the planning study.

In order to create a system view of compliance with CSAPR for the purpose of evaluating Weston Unit 3 compliance options, various combinations of compliance options or plans were evaluated in terms of compliance, economics and reliability. This evaluation produced the reference plan that was then used to evaluate specific compliance options.

In two of the three planning futures (Futures 1&2) the planning analysis confirms that achieving compliance with Phase 2 of CSAPR by installing ReACT on Weston Unit 3 would result in substantial reductions in PVRR when compared to the compliance option of replacing Weston Unit 3 after 12/2016. In Future 1, the PVRR savings range from \$166 million to \$295 million. In Future 2, the PVRR savings range from \$44 million to \$337 million.

Future 3 assumes low fuel prices and a CO₂ adder and provides the strongest economic argument for replacing coal units rather than investing in emission controls. Even in that future, the economics of investment in ReACT for Weston Unit 3 is comparable to the economics of replacing Weston Unit 3 after 12/2016.

In Futures 1&2 installing ReACT compared to replacing Weston Unit 3 after 12/2016 results in the same level of substantial reductions in PVRR for the following changes in reference plan assumptions (i.e., base load forecast [REDACTED]):

- A. Base load forecast with [REDACTED]
- B. Low load forecast with [REDACTED]

The economics of ReACT are independent of how [REDACTED]. A lower load forecast does not materially change the economics of ReACT compared to replacing Weston Unit 3 after 12/2016.

ReACT is a superior compliance option compared to the dry FGD control system because ReACT provides NO_x reductions without the installation of any additional technologies. By contrast, the dry FGD system requires the installation of a SCR system to provide NO_x reductions. The installation of a dry FGD and SCR system causes a significant increase in PVRR (\$144 million to \$160 million) compared to ReACT.

4.0 OPERATING PARAMETERS

4.1 COST OF OPERATION

Table 4-1 provides a high level cost breakdown of the operating parameters of the ReACT systems discussed in **Section 1.2, Selected Technology**. The O&M costs were developed based on the operating characteristics of Weston Unit 3 burning PRB coal and performance projections from the ReACT O&M.

Table 4-1 ReACT Systems – Operating Cost Breakdown

ReACT Operating Cost Summary	Units	ReACT
Cost Basis Year		2011
<u>Important Operating Parameters</u> (@ full load unless capacity factor is shown)		
Activated Coke (makeup):	lbs/hr	377
	tons/day	4.5
29% Ammonia	lbs/hr	853
	tons/day	10
Natural Gas	MMBtu/hr	11.5
SO ₂ Removal Efficiency	%	90
SO ₂ Removed:	lbs/MMBtu	0.61
	lbs/hr	2,088
	tons/hr	1.04
@ 81% capacity factor	tons/year	7,408
SO ₂ Emitted: @ 0.68 lb/mmbtu SO ₂ inlet	lbs/MMBtu	0.07
@ 81% capacity factor	tons/year	850
Sulfuric Acid By-product	lbs/hr	3366
	tons/day	40
@ 81% capacity factor	tons/year	11,942
FGD Sludge to Disposal (dry, w/o fly ash)	lbs/hr	0
Mercury Contaminated Activated Coke Waste		
(disposal every 18-36 months) avg :	tons	33
Activated Coke Fines	lbs/hr	220
@ 81% capacity factor	tons/yr	781
Cooling Water (Clarified Water) to ReACT System (returned to cooling tower)	gpm	2,400
Consumptive Service Water Use for ReACT System (not returned to cooling tower)	gpm	71
Steam Supply for ReACT System (condensate returned)	Lb/hr	2521

PUBLIC VERSION

Total FGD Power Consumption	kW	4800
Fixed O&M Costs		
Number of Operators (include maint & admin)		8
Operating Labor Cost	1000\$/yr	\$430
Maintenance Labor and Materials Cost	1000\$/yr	\$2501
Administrative and Support Labor	1000\$/yr	\$217
TOTAL First Year Fixed O&M Cost	1000\$/yr	\$3147
Variable Operating Costs (@ 81% capacity factor)		
Activated Coke Costs	1000\$/yr	\$2060
29% Ammonia Costs	1000\$/yr	\$802
Natural Gas Costs	1000\$/yr	\$408
By-product Sales (Sulfuric Acid)	1000\$/yr	(\$299)
Waste Disposal Cost for FGD System (Act Coke)**	1000\$/yr	\$357
Steam Cost	1000\$/yr	\$69
Water Cost	1000\$/yr	\$15
TOTAL First Year Variable Cost*	1000\$/yr	\$3,416
TOTAL First Year Variable Cost*	\$/MWhr	\$1.46
*excludes auxiliary power and annualized waste cost		
**18 month cycle for waste disposal		

4.2 OPERATING CHARACTERISTICS

The installation and operation of the proposed ReACT system will have the following operating characteristics:

Flue Gas Process Flow – The ReACT system has two independent 50% flow sections. Flue gas from the existing Weston Unit 3 fabric filter will be directed to two new ID fans, two adsorber beds and returns to the existing stack through a common duct.

ID Fan Replacement – The installation of the ReACT equipment will require replacement of the ID fans in the flue gas path to overcome the added pressure drop associated with the new control equipment. The fans will be located process-wise between the existing fabric filter and the new ReACT adsorber beds. The cost to replace the existing ID fans have been incorporated into the project capital cost estimate.

Adsorber Beds – The adsorber is the main component that houses the AC. Flue gas contacts the AC. In the adsorber beds, SO₂, mercury, and small amounts of other pollutants are adsorbed to the surface of the AC, which is transferred to the regeneration island. Clean flue gas exits the adsorber and is directed to the existing plant stack.

In addition to the adsorption process of SO₂ and mercury, a nitrogen oxide reaction takes place in the presence of ammonia resulting in a reduction of NO_x emissions.

Regeneration Island – The regeneration island receives the AC from the adsorber and processes the material at specific temperature zones to drive off the SO₂ as a SRG. The SRG is then directed to the acid plant. During the regeneration process, mercury remains adsorbed and collects in a specific temperature zone in the regenerator. The mercury contaminated AC in the regenerator is removed from this specific temperature zone during scheduled routine outages every 18 – 36 months. The mercury contaminated AC may be considered a hazardous waste and will be disposed or recycled in an appropriate facility.

The regeneration island is designed with a direct natural gas heater to obtain the appropriate temperature zones to drive off the SO₂ and generates the SRG. The cooled exhaust from the natural gas heater is reintroduced in the inlet duct to the adsorber bed or routed to the main stack. The exact path of the SRG from the regenerator to the acid plant will be determined during the final design phase of the project.

Sulfuric Acid Plant – SRG from the regenerator is directed to the acid plant where commercial grade sulfuric acid is produced and supplied to the market. Included in the design is a small natural gas or electric heater used during start up and low load operation. The heater exhaust and remaining gas flow from the acid plant is directed back to the adsorber inlet where it comesles with the boiler flue gas to be cleaned and eventually exits the main stack.

The marketable sulfuric acid is stored in an acid storage tank designed for an approximate storage of 15 days at maximum rate of production. The storage tank also serves as a surge volume to accommodate shipping logistics. Although there is a possibility of transport by rail, it is anticipated that 12 tanker trucks per week will transport sulfuric acid to market.

Ammonia Storage – Ammonia will be utilized in the ReACT process. At this time it is expected that aqueous ammonia will be utilized for the process. Currently, Weston Unit 4 on-site already utilizes aqueous ammonia for NO_x control and has handling facilities and procedures to accommodate the presence of the substance on-site. Expansion of the existing ammonia storage and handling facilities may be required for this project.

The ammonia storage tanks will be located near the center of the plant site near the existing Weston Unit 4 ammonia storage tanks. Ammonia will be pumped to the process island, vaporized, and injected into the flue gas stream at the absorber inlet and at times the regenerator outlet. Delivery of ammonia is anticipated to be the equivalent of 3 tanker trucks of 29% ammonia per week. This will increase the total ammonia deliveries to the Weston Generation Station from the equivalent of approximately 3 tanker trucks per week to 5 tanker trucks per week.

AC Pellet Handling – ReACT circulates the AC from the adsorber to the regenerator, and then back to the adsorber. AC is gradually reduced in size through abrasion and chemical loss in the regenerator. As a result, an AC make up system is utilized to maintain a volume of AC for optimal process operation. It is anticipated that 2 trucks of AC will be delivered to the site weekly.

AC Pellet Fines – The degradation of the AC creates AC fines. Preliminary engineering and design indicate these fines can be collected, mixed with coal and burned in the combustion process as a secondary fuel.

Truck Traffic – As described earlier, the plan is to utilize trucks for delivery of aqueous ammonia, delivery of AC pellets, and shipment of sulfuric acid. Truck traffic around the site will increase by approximately 17 visits per week, depending on delivery schedules and unit operation

Rail Traffic—W PS is not planning an increase in rail traffic associated with this project. However, depending upon future market requirements, use of rail for AC delivery, ammonia delivery and/or sulfuric acid by-product shipment could become a viable option in the future.

Operating Personnel – Analysis of the ReACT operating requirements suggests that additional staff will be necessary to properly operate and maintain the system on a 24-hour daily basis. The estimated number of new positions ranges between 5 and 8 personnel based on technology site visits and input from existing plant management. The final number of personnel to support the ReACT operation is dependent upon detailed engineering, ease of operation, and maintenance efficiencies.

The cost estimates provided include the operating labor estimate of 8 positions. The new positions will be incorporated into the existing plant organization and be responsible for day to day operations and equipment checks, routine maintenance and repair activities, laboratory testing, compliance monitoring, material handling, and quality control.

ReACT Process Control – The system will be designed to be fully automated from the existing central control room and instrumented to allow complete system control, operation, and alarming. All system instrumentation and control logic will be integrated into the existing Weston Unit 3 distributed control and operator interface system.

Training & Plant Procedures- The ReACT system is a new technology to WPS. Due to the nature of this technology, detailed procedures and an extensive training program will be employed to prepare the plant staff for initial start up and long-term operation.

Plant Area Occupied by ReACT Equipment – The new equipment and facilities will occupy areas adjacent to the operating unit fabric filter, crusher house, and cooling tower. Use of this space will impact operations and maintenance access, vehicle traffic and areas used for outages (crane and material lay down and staging). However, there is sufficient area at other locations on-site to replace this loss of space.

Water Consumption and Sources – There are two primary cooling requirements that may increase the water consumption for the plant after the installation and startup of the ReACT system.

The acid plant requires water for cooling the acid by-product along with possibly a small consumptive use for dilution and gas cleaning makeup. The current design will incorporate use of the existing Weston Unit 3 cooling tower for this heat rejection. Low levels of water make-up due to evaporation and tower blow-down will be required at full operating conditions.

Additionally, water is currently planned to be used for miscellaneous bearing and equipment cooling purposes. Intermittent uses of plant consumptive service water will be used for wash-down and cleanup as needed. This water will likely be cooling tower water returned to the tower and some of which will be a consumptive use.

The relatively low quantity (estimated to be up to 71 gpm) ReACT make-up water streams will be supplied from the existing clarified river water system. The adequacy of this source along with verification of the use streams will be reviewed in conjunction with the ReACT vendor and engineered for the final configuration of the makeup water system design concept, including cooling tower impacts on Weston Unit 3. It is expected that these new water consumption requirements will be minor and within the existing permit thresholds.

Wastewater System – The sulfuric acid process produces a small liquid waste stream from the acid plant. Preliminary engineering indicates this waste-stream can be re-introduced into the fabric filter for re-entry into the process.

Chemical Hazards – The ReACT process requires ammonia as a reagent and provides a marketable sulfuric acid by-product. There are chemical hazards associated with the handling of reagents and by-products. The site currently utilizes aqueous ammonia on Weston Unit 4 as part of the NO_x control technology and sulfuric acid for the de-mineralized water systems. The site has experience with these chemicals and practices appropriate safe-handling procedures. The loading and off loading of these chemicals will be part of the system and designed to minimize risk to individuals involved with shipping and receiving logistics.

Catalyst Handling - A vanadium catalyst is present in the sulfuric acid plant which is replaced on an infrequent basis (7–10 yrs). This catalyst can either be reprocessed by the catalyst vendor or disposed of at the appropriate disposal facility. At this time, reprocessing is the preferred approach for replacement.

Auxiliary Power Consumption – The ReACT equipment and supporting auxiliary components will add an estimated 4,800-kW parasitic load at unit full load and ReACT design basis operation. The primary power consumers that were included in the current cost estimates are the following components:

- New ID fans with increased pressure requirements
- ReACT process island
- Acid plant process island
- Compressed air and nitrogen system

Potential Steam Use – The ReACT system design incorporates the use of auxiliary steam in the ammonia vaporization process and for heat tracing of the conveyors. The additional auxiliary steam usage will have minimal impact on overall plant performance and capability.

4.3 EFFECT ON QUALITY AND RELIABILITY OPERATING CHARACTERISTICS

After initial start-up, the system will have minimal reliability and quality impacts on the Weston Unit 3 facility.

4.3.1 Plant Performance Requirements

The ReACT system will be designed to meet the following performance requirements:

- Plant Operating Period: Appropriate design and equipment redundancy to maintain ReACT system reliability.
- Spare Parts Philosophy: Installed spares for critical components will be included. Critical spare parts will be part of inventory control to minimize outage risk and outage length.
- Duty Cycle: This facility will be designed for base load operation. The project anticipates there will be a reasonable system start-up and break-in period.

4.4 START-UP AND COMMISSIONING

At the initial start-up of a ReACT system, following construction and check-out, the steady state condition of the AC has not yet been reached. The activity of the AC for SO₂ and NO_x control will gradually improve as the system operates.

For the first start-up, the system is loaded with a special grade of AC. Compared to make-up AC, the "Initial Charge" of a special grade of AC has been processed to a higher degree of activation for SO₂. The "Initial Charge" material enables the ReACT system to start up with SO₂ emissions in compliance. The initial AC charge material for NO_x control will be lower (approximately 10% lower). It will increase over the "Initial Charge" period. Normal operation of the process improves activity for both SO₂ and NO_x control. The one-time "Initial Charge" is expected to be part of the ReACT system until it is gradually replaced by the consumption of AC by the process over a period of up to 180 days of continuous operation.

There are options available that can reduce the seasoning time of the AC. It is expected that the need to reduce the seasoning time will be driven primarily by final design requirements, the pertinent permit requirements, and the timeline included in any expected resolution of the EPA NOV.

5.0 DESCRIPTION AND COST OF PROPERTY BEING REPLACED

The current configuration and general arrangement of the ReACT system was developed with constructability in mind has been optimized to reduce property relocation and demolition, and is designed to minimize outage durations.

5.1 EQUIPMENT REMOVAL AND RELOCATION

The conceptual design of the ReACT system evaluated various general arrangements and site locations adjacent to the Weston Unit 3 fabric filter. Major pieces of equipment have been conceptually placed, but details concerning demolition and/or relocation of small scope items remains to be evaluated. An allowance for the expected cost to accomplish these tasks is included in the current retrofit cost estimates. Components/facilities that might require demolition, modifications, or relocation include the following:

- Electrical conduit and duct banks
- Existing pipelines, both above and below ground
- Structural steel members may need to be relocated in some cases to make room for the equipment and ductwork
- Stairways, lighting, and platforms may need to be relocated or modified to maintain access to existing equipment
- Existing instrumentation may need to be relocated to maintain access and measurement of operating conditions
- Bridging for cranes across existing underground utilities and circulating water lines
- Modifications to existing fabric filter ductwork

The current cost estimate includes approximately \$2.0 million dollars for demolition and removal of existing equipment. The decision of demolition or abandonment of existing ID fans and fabric filter exhaust ductwork will be determined in detailed design. The net book value of the assets to be demolished, removed, and abandoned in place is approximately \$210,000 at the time of retirement.

6.0 EMISSIONS CONTROL TECHNOLOGY SELECTION

The following section describes the selection of the emission control technologies from a technical point of view. The economic aspects of these technologies are evaluated in the Need and Analysis Section (**Section 3**).

The complete technical analysis of these technology options, including a discussion of the pros and cons of their installation at Weston Unit 3, can be found in **Appendix C**.

6.1 TECHNOLOGY SELECTION PROCESS

Before selecting ReACT as the preferred emission control technology for Weston Unit 3, WPS utilized a two tier selection process to determine which control technologies are competitive compared to ReACT. The first tier consisted of screening out technologies that have fatal (or near fatal) technical flaws. The second tier consisted of screening out technologies that do not result in emission reduction that ensures compliance with CSAPR, or a similarly stringent transport rule replacement and the expected resolution of the EPA NOV.

6.2 SUMMARY OF TECHNOLOGY SELECTION

Tier 1 Screen – Fatal Or Near Fatal Technical Flaws

The Dry FGD Circulating Dry Scrubber (CDS) technology, should not be considered further in the Need and Analysis Section. As stated in **Appendix C**, the dry FGD CDS has the following flaws:

- CDS absorber vessels are typically limited to 150-200 MW although some vendors are developing vessels large enough for 300 MW of flue gas. There are only a few large boiler installations operating with CDS FGD systems, and the experience base for CDS FGD systems operating on PRB coal-fired boilers is very limited.
- The CDS is not flexible at handling varying unit loads, such as would be the case at Weston Unit 3. The CDS requires a minimum gas flow rate to maintain the fluidized nature of the bed. If the unit load drops below this minimum, a gas recycle system is required to maintain performance of the bed. The gas recycle can add significant expense and complexity to the system.
- A Typical CDS FGD design has an elevated fabric filter to allow for the recycle of the collected solids, via air slides, to the CDS absorber vessel without the use of a storage silo. Retrofitting a CDS FGD to an existing fabric filter would require the development of site specific material handling solutions to allow for the recycle of the large volumes of material collected in the fabric filter from a CDS FGD. This would not be a standard vendor offering and would result in additional cost.

Among the potential types of pollution control equipment for SO₂, NO_x and mercury emission reduction is a wet FGD. The mercury concentrated in the blowdown from a wet FGD cannot be adequately removed prior to discharge, and the river is identified as an impaired water body for mercury which restricts discharge concentrations to background levels. Therefore, a wet FGD is unlikely to get permitted with a discharge to the Wisconsin River.

The “Effluent Guidelines” for steam electric facilities will be updated with a draft rule coming out in November 2012. One of the primary areas of focus for this rulemaking is wastewater discharged from a wet FGD.

There will be additional regulation of selenium for which biological treatment systems will likely be required to meet the discharge standards. These systems are still in an “emerging technology” phase. Creation of onsite wetlands, in which vegetation removes the selenium, or the use of advanced bioreactors are the types of technologies that are currently being tested. The few installations that have tried these systems have had very inconsistent results. For these reasons, a wet FGD is not a feasible option for SO₂ control at the Weston Generating Station.

Tier 2 Screen - Compliant Emission Reduction Performance (SO₂ and NO_x)

Based on the Tier 2 screen compliant emission reduction performance, further analysis of the emissions reduction controls should be limited to a combination of the SCR and Dry FGD only or ReACT. The SNCR and Dry Sorbent Injection (DSI) technologies cannot be relied upon to achieve the level of reduction that ensures both compliance with CSAPR, or a similarly stringent transport rule replacement and the expected resolution of the EPA NOV.

Therefore, in order to achieve a fair comparison of the SO₂ and possible NO_x emission reduction performance associated with the ReACT, the alternative dry SO₂ emission control systems need to be combined with an SCR, as opposed to a SNCR.

The following emission control systems are evaluated in **Section 3**:

1. Dry FGD, Spray Dryer Absorber (SDA) with SCR, and
2. Multi-Pollutant (ReACT)

6.3 ADDITIONAL TECHNOLOGY ATTRIBUTES THAT SUPPORT SELECTION OF REACT

The ReACT system has the following operational advantages:

- Produces no mercury contaminated water that will require wastewater treatment.
- The mercury is captured in the AC in a specific temperature zone, with that zone of the AC removed from the regenerator every few years, and disposed of as a potentially hazardous solid waste product.
- In Japan, this material has been processed to recover the captured mercury, and a similar approach could be taken at Weston Unit 3 depending upon the economics of processing vs. disposing of this material. Has superior capture and control of mercury.
- The ReACT system has demonstrated greater than 90% reduction in mercury emissions and its collection efficiency is not dependent upon the speciation of the mercury.
- The existing ACI system is expected to only be available to provide operational flexibility to meet current and future emissions control requirements.

PUBLIC VERSION

- Is a commercially proven technology. The technology has been operated successfully on large utility boilers with a 350 MW unit in operation since 1995, and two 600 MW coal-fired boilers that began operation in 2002 and in 2009.
- Provides cost-effective control. The ReACT system has been demonstrated to reliably achieve reductions of SO₂ and mercury with the co-benefit of NO_x reductions. The technology therefore will provide Weston Unit 3 with the flexibility to meet more stringent emission controls on multiple pollutants that may be imposed in the future.
- Utilizes the existing stack. The flue gas exiting the ReACT system is not saturated with water vapor. Therefore, the stack exit velocity requirements can be maintained and the potential for corrosion of the existing stack liner is minimal given the high levels of acid gas removal that can be achieved. This allows the existing stack at Weston Unit 3 to remain in operation, saving considerable project cost associated with construction of a new stack.
- Provides additional co-benefits. Fly ash collected in the fabric filter will continue to be beneficially re-used because ReACT is located downstream of the fabric filter. The ReACT system will also produce a commercial grade sulfuric acid by-product that can be sold for use by other industries.

7.0 ENVIRONMENTAL IMPACTS AND PERMITS

7.1 MAPS AND DRAWINGS OF THE PROPOSED PROJECT SITE

Preliminary general site arrangement drawings for the proposed project is provided in **Appendix A** as follows:

- HRC Dwg. PR002-H0010-1000 – 360MW ReACT System General Arrangement Plan
- HRC Dwg. PR002-H0010-1001 – 360MW ReACT System General Arrangement Elevation
- URS/WPS Dwg. S-561 – Plot Plan Weston Unit 3 AQCS Project Site Plan

7.2 EMISSIONS REDUCTIONS

The proposed project will reduce SO₂, acid gases, NO_x, and mercury emissions from Weston Unit 3. Controlling SO₂ emissions will reduce acid rain and the formation of fine particulates in the atmosphere. Mercury and acid gas emissions will be reduced to levels that comply with MATS and the Wisconsin mercury rule, with additional flexibility to meet more stringent future requirements.

7.3 PROXIMITY TO FLOODPLAINS

The area chosen for the location of the proposed project is not within a 100-year floodplain.

7.4 INFORMATION ON APPLICABLE ENVIRONMENTAL FACTORS

Several environmental factors have been considered for the proposed emissions reduction project. Studies have been performed at the site, evaluating the presence of features that could be impacted by the project. The studies performed include the following:

- Archaeological and Historic Resources
- Threatened or Endangered Species
- Solid Waste
- Hazardous Waste
- Waste By-product
- Water resources/Water Supply
- Wastewater Discharge
- Hazardous Materials

Additional information is found in the following sections.

7.4.1 Archaeological and Historic Resources

A search of the Wisconsin Historic Preservation Database indicates there are no known archaeological or historic resources in the construction footprint of the project.

7.4.2 Threatened and Endangered Species

There is an active peregrine falcon (*Falco peregrinus*), nest box on the roof of the Weston Unit 3 power plant. The nest box has been active since 2004 and to date, has yielded 14 successful hatchlings. Most-recently in 2011, three eggs were laid between March 25 and April 6 and yielded two chicks. Consultation with the WDNR will be initiated prior to construction to address concerns related to the peregrine falcons if they are present during construction.

The U.S. Fish and Wildlife Service indicated that bald eagle (*Haliaeetus leucocephalus*), breeding habitat occurs in Marathon County. The bald eagle is delisted from the State and Federal threatened list and is not presently a significant concern at the Weston Generating Station.

During construction, all ground-disturbing activities will occur on the existing Weston property, with no adverse impacts to critical vegetative habitats for endangered or threatened species. In addition, appropriate Best Management Practices (BMPs) and erosion control techniques will be used to prevent impacts to aquatic habitats. Accordingly, no adverse impacts to threatened or endangered species are expected.

7.4.3 Solid Waste

Currently, most of the bottom ash is beneficially reused. Fly ash is sold as a useful by-product. The existing fabric filters are expected to remain in operation after the addition of the ReACT.

Weston Unit 3 bottom ash and other combustion by-products collected upstream of the fabric filter are sluiced to the ash water settling ponds where the ash is allowed to settle out and the water recaptured. The collected ash is periodically removed from the ponds and stored temporarily on-site in the landfill area. The ash is then periodically trucked off-site for reuse. Weston Unit 3 fly ash is collected from the fabric filter and pneumatically transported to the fly ash silo. The fly ash is periodically transferred from the ash silo to either a fly ash storage building or to enclosed trucks and transported off-site for reuse.

WPS has the goal to continue to sell the Weston Unit 3 fly ash for use in concrete or other beneficial reuse. Since the ReACT system is installed downstream of the fabric filter, these solid waste streams will, for the most part, not be impacted. Fly ash testing in coordination with ash marketer will insure ash by-product quality is maintained.

Additional potential solid waste streams generated by ReACT system include:

- A portion of AC from the regenerator needs to be removed every 18 to 36 months (depending on the flue gas mercury concentrations leaving the fabric filter and entering ReACT). Mercury and other metals removed from the flue gas are thermally retained in the AC. (discussed further in **Section 7.3.4 Hazardous Waste**)
- AC fines from the regenerator outlet that are removed as dust, are planned to be used as a secondary fuel in the unit boiler.
- Used vanadium catalyst from the acid plant needs to be replaced once every 7-10 years. This material may be either disposed of or recycled by the catalyst supplier.

7.4.4 Hazardous Waste

The ReACT system will extract mercury from the flue gas. The mercury will accumulate in a specific section of the regenerator column (vessel) and be adsorbed to the AC pellets. Periodically (every 18 to 36 months), the mercury needs to be removed from the system by

removing that section of AC pellets from the column and properly disposing or recycling the mercury-contaminated AC pellets. Due to the concentration of mercury, the mercury-contaminated AC could be classified as hazardous waste and could need to be disposed of at a licensed hazardous waste landfill. Since there are no licensed hazardous waste landfills in the State of Wisconsin, the waste will have to be transported outside of the state. The amount of mercury-contaminated AC pellets produced will average approximately 33 tons of AC pellets per clean-out. Detailed design will continue to investigate a method to recycle the mercury – contaminated AC pellets.

The ReACT system utilizes a vanadium catalyst in the acid plant portion of the system. This catalyst periodically needs to be renewed by regenerating it at an off-site facility. The total amount of catalyst to be regenerated at an off-site facility is expected to be 800 cubic feet approximately every 8 years.

7.4.5 Waste By-product

The ReACT system is designed to remove sulfur from the flue gas. The sulfur adsorbs to the AC pellets. The system continues to regenerate the activated AC pellets by removing the sulfur compounds that have adsorbed to the pellets. The sulfur compounds are converted into a commercial grade sulfuric acid by-product by the acid plant portion of the system. At expected operation, the acid plant is expected to yield the equivalent of 40 tons of 93-98% sulfuric acid on a daily basis. This acid will be temporarily stored on-site and shipped off-site as the market demands.

7.4.6 Water Resources/Water Supply

To operate the ReACT system, plant water consumption will increase slightly. As much as 70 gpm of make-up water could be required for cooling and dilution within the acid plant. The remaining cooling water will be cycled through the cooling tower and re-used. This cooling water can be of a lower quality such as another wastewater stream. The water quality of each source will need to be verified for its suitability for the process.

Plant water usage and consumption will increase with the addition of the ReACT system to account for the water lost to evaporation and blow-down. The specific water consumption rate will be established with the selection of the specific ReACT acid plant vendor, ReACT system, and balance of plant equipment. Efforts will be made to conserve water by using air cooling to replace some of the cooling water demands as with some of the fan oil coolers. River water via the plant's service water system will be used to supply the required water quantity. WPS is aware of the present limits of the Consumptive Water Use Permit for the Weston Site (Units 1, 2, 3, and 4) and will make every effort to use and/or reuse the existing permitted water. It is expected that these new water consumption requirements are minor and within the existing permit thresholds.

7.4.7 Wastewater Discharge

Weston Unit 3's wastewater discharge quality will not be affected by the addition of the proposed emission reduction systems.

There will be a small (2-14gpm) wastewater effluent from the ReACT acid plant. It will require a new handling system at the Weston Generating Station. Depending on the characteristics of the

ReACT waste stream, the wastewater may be treated or reused within the station to cool flue gas prior to entering the fabric filter. Modifications to the existing wastewater treatment facility or a new treatment system dedicated to the ReACT waste stream will not be required. There also will be occasional drainage of sumps and containment areas due to storm run-off or area cleanup. These areas would include the acid plant, the balance of plant equipment and the ReACT process island. Any wastewater effluent discharged from the ReACT system via a wastewater treatment system will comply with Wisconsin Pollutant Discharge Elimination System (WPDES) permit requirements as established by the WDNR.

7.4.8 Hazardous Materials

The ReACT process will utilize ammonia injection to aid in the removal of NO_x from the flue gas. At this time it is expected that aqueous ammonia will be utilized for the process. Currently, Weston Unit 4 already utilizes aqueous ammonia for NO_x control and has handling facilities and procedures to accommodate the presence of the substance. Expansion of the existing ammonia storage and handling facilities will be required for this project.

7.5 LIST OF PERMITS AND APPROVALS REQUIRED

Table 7-1 is a summary of the potential permits and approvals that are or may be required for construction and operation of the Weston Unit 3 ReACT system. This Certificate of Authority application is currently the only permit that has been submitted for approval.

PUBLIC VERSION

Table 7-1 Potential Permits and Approvals

Item	Agency	Activity	Permit/Approval
1	PSC	Replacement, modification or addition at a generating plant with cost greater than \$5 million	Certificate of Authority
2	WDNR	Construction, installation or alteration of an air pollutant source	Air construction permit, modification of air quality operation permit and acid rain recertification.
3	WDNR	New discharge of wastewater surface or groundwater or material changes to existing permitted discharges	WPDES Surface Water Discharge Permit Modification
4	WDNR	Discharge of storm water from construction sites impacting 5 acres or more	WPDES General Storm Water Construction Permit
5	WDNR	Discharge of storm water from plant operations	Modify existing storm water pollution prevention plan
6	WDNR	Storage of coal combustion by-products	Post-operational approval under FR 502
7	WDNR	Mercury Removal through AC	Change in Hazardous Waste Generation Status
8	WDNR	Increase in consumptive water use on site	Conditional Water Loss Approval
9	WDNR	Integrity testing of equipment	Hydrostatic Test Water Permit
10	WDNR	Increase in current high capacity well withdrawal rates	High Capacity Well Permit Modification
11	WDNR	Installation of de-watering wells	High Capacity De-watering Permit
12	WDNR	General construction trench de-watering	Pit/Trench De-watering Permit
13	U.S. Army Corps of Engineers and WDNR	Wetlands impacts, construction within surface waters	Section 404 and Chapter 30 permits
14	Wisconsin Department of Commerce (WDC)	Construction of all buildings structures, and storm water management	Approval of Plans Specifications, and Storm Water Permit
15	WDC	Installation of dust filtering and HVAC equipment	Approval of Plans and Specifications
16	WDC	Construction of plumbing facilities	Approval of Plans and Specifications
17	Department of Transportation	Delivery of large/heavy components	Over Heavy Vehicles Permit
18	Environmental Protection Agency (EPA)	Use of Aqueous Ammonia onsite above 10,000 pounds	Submission of Risk Management Plan

PUBLIC VERSION

Item	Agency	Activity	Permit/Approval
19	Village of Kronenwetter	Construction of structures, foundations, buildings	Building Permit
20	Village of Kronenwetter	Demonstration that new structures meet applicable codes prior to occupancy	Certificate of Occupancy
21	Village of Kronenwetter		Conditional Use Permit
22	Village of Kronenwetter		Site Plan Approval
23	Village of Kronenwetter		Erosion Control Permit
24	Village of Kronenwetter	Construction of new facilities	Zoning variance for the height of the building. Zoning variance for site lighting.
25	Village of Kronenwetter	Delivery of large/heavy components	Over Heavy Vehicle Permit
26	Village of Rothschild	Construction of structures, foundations, buildings	Building Permit
27	Village of Rothschild	Construction of new facilities	Zoning variance for the height of the building. Zoning variance for site lighting.
28	Village of Rothschild	Delivery of large/heavy components	Over Heavy Vehicle Permit
29	Village of Rothschild	Excavation activities	Excavation Permit

8.0 DESIGNATION OF PUBLIC UTILITIES AND OTHER AFFECTED

Weston Unit 3 is wholly-owned and operated by WPS. There are no other public utilities affected by this project. All other entities, such as the Villages of Kronenwetter and Rothschild, will be notified during the permitting and approval process.

APPENDIX A

GENERAL SITE ARRANGEMENT

EXISTING FACILITIES LEGEND:

- 1 UNIT 3
- 2 UNIT 4 BUILDING
- 3 UNIT 2 CHIMNEY
- 4 UNIT 2 BARGE
- 5 UNIT 2 BARGE
- 6 UNIT 2 BARGE
- 7 UNIT 2 BARGE
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- 40 UNIT 2 BARGE

UNIT 3 NEW ECD FACILITIES LEGEND:

- 41 NEW BULLET DUCT
- 42 NEW BULLET DUCT
- 43 NEW BULLET DUCT
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- 80 NEW BULLET DUCT

- NOTES:
- 1-NEW SITE BASELINE COORDINATE N. 10000, E. 10000 IS EQUIVALENT TO EXISTING UNIT 3 BASELINE COORDINATE N. 10000, E. 10000.
 - 2-NEW SITE BASELINE COORDINATE N. 10000, E. 10000 IS EQUIVALENT TO EXISTING UNIT 3 BASELINE COORDINATE N. 10000, E. 10000.
 - 3-NEW SITE BASELINE COORDINATE N. 10000, E. 10000 IS EQUIVALENT TO EXISTING UNIT 3 BASELINE COORDINATE N. 10000, E. 10000.
 - 4-NEW SITE BASELINE COORDINATE N. 10000, E. 10000 IS EQUIVALENT TO EXISTING UNIT 3 BASELINE COORDINATE N. 10000, E. 10000.

PROJECT PLAN

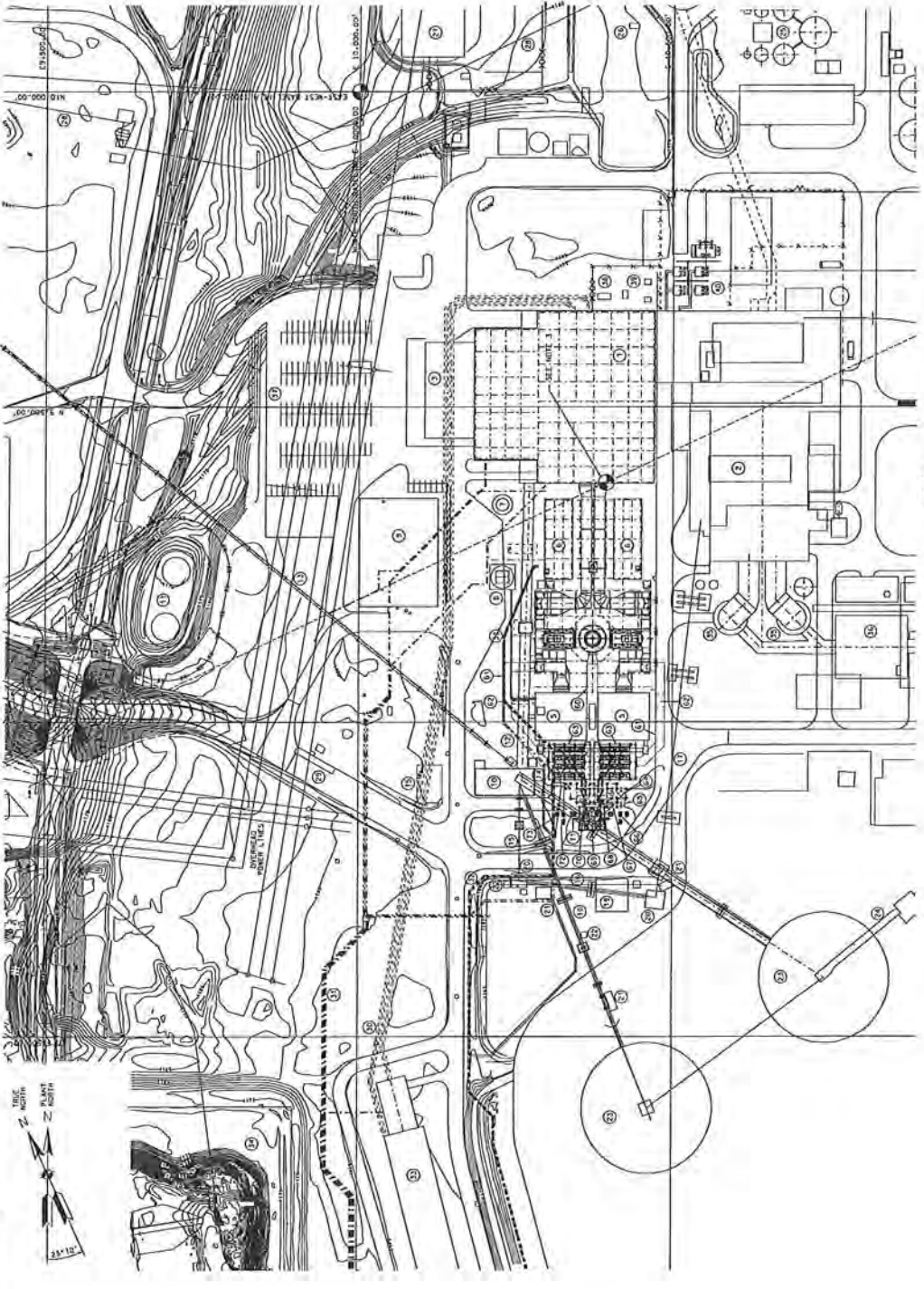
WESTON GENERATION STATION
WESTON 3 ADSS PROJECT
MAUSAU, WISCONSIN

URS

10000 N. 10000 E. 10000
10000 N. 10000 E. 10000
10000 N. 10000 E. 10000

DATE: 5-15-11
SCALE: 1"=40'

NO.	DESCRIPTION	DATE	BY	CHKD.	APPROVED
1	PROJECT PLAN	5-15-11	J. J. J.	J. J. J.	J. J. J.
2	PROJECT PLAN	5-15-11	J. J. J.	J. J. J.	J. J. J.
3	PROJECT PLAN	5-15-11	J. J. J.	J. J. J.	J. J. J.
4	PROJECT PLAN	5-15-11	J. J. J.	J. J. J.	J. J. J.
5	PROJECT PLAN	5-15-11	J. J. J.	J. J. J.	J. J. J.
6	PROJECT PLAN	5-15-11	J. J. J.	J. J. J.	J. J. J.
7	PROJECT PLAN	5-15-11	J. J. J.	J. J. J.	J. J. J.
8	PROJECT PLAN	5-15-11	J. J. J.	J. J. J.	J. J. J.
9	PROJECT PLAN	5-15-11	J. J. J.	J. J. J.	J. J. J.
10	PROJECT PLAN	5-15-11	J. J. J.	J. J. J.	J. J. J.



APPENDIX B

Needs Analysis

B.1 ABSTRACT

This study addresses the following issues specific to Weston Unit 3:

- Compare economics of ReACT on Weston Unit 3 to replacement of Weston Unit 3 to achieve SO₂ reductions that would be required by CSAPR or a similar replacement regulation, as well as those likely required by a resolution of the EPA NOV.
- Assess impact on reliability and exposure to volatile capacity market prices if WPS replaces coal fuelled capacity in the 2015 – 2020 timeframe.
- Compare economics of ReACT to a Dry FGD/SCR to achieve NO_x reductions that are required by CSAPR or a similar replacement regulation, as well as those likely required by resolution of the EPA NOV.

B.2 PURPOSE

EPA issued CSAPR in July 2011. WPS and several other parties challenged the rule, which has been temporarily stayed by the D.C. Circuit Court of Appeals pending a decision on the merits of the various challenges to the rule. If the rule is reinstated or a similar replacement rule is promulgated in the future, WPS would be required either to achieve significant emissions reductions in SO₂, annual NO_x and ozone-season NO_x (May – September) or to purchase additional allowances beyond WPS allocations. The rule has two phases: Phase 1 begins January 1, 2012 (currently stayed pending court action) and Phase 2 begins January 1, 2014.

This study evaluates alternative compliance plans that will assure WPS compliance with Phase 2 of CSAPR. The focus of this study is compliance options for Weston Unit 3 in 2014 and beyond.


In order to create a system view of compliance with CSAPR for the purpose of evaluating Weston Unit 3 compliance options, various combinations of compliance options have been incorporated into compliance plans. These plans are evaluated in terms of compliance, economics and reliability. This evaluation determined the reference plan that was used to evaluate specific compliance options at Weston Unit 3.

In addition to compliance with CSAPR, this study also takes into account the fact that WPS received an NOV from EPA alleging violations of NSR and PSD regulations at the Weston Generating Station. Although no settlement on the NOV has been reached and may not be reached, this study includes consideration of the reductions in SO₂ and NO_x that would likely be required from Weston Unit 3 by a resolution of the EPA NOV. In the event a resolution of the EPA NOV is reached, this study would be updated to reflect the terms and conditions of the settlement.

The study reflects compliance with known, final environmental regulations: CSAPR, MATS (compliance 4/2015), and Wisconsin's Hg rule (NR 446). The CSAPR rules, as finalized by EPA in July 2011, were assumed for this study subject to later corrections that were recently finalized by the EPA. The study therefore assumes that even if CSAPR is reversed by the courts, a similar transport rule will replace it.

The study also assumes that the EPA NOV will result in a settlement that is representative of other EPA NOV settlements, i.e., a settlement that will require significant SO₂ and NO_x reductions at Weston Unit 3.

[illegible]



Major investment in emission controls was limited to Pulliam 7&8, Weston 3, and Columbia 1&2 due to economy of scale and unit efficiency. An evaluation of the potential for economic capital investment in Pulliam 5&6 and Weston 1&2 to remain as coal fuelled units was made to confirm this assumption.

The new unit expansion plans were optimized to reflect the lowest cost expansion plan for a given compliance plan.

Short term compliance with CSAPR (pre-2014), both for the region and WPS, was assumed to be achieved by re-dispatch of coal units to reduce coal MWh output and the corresponding SO₂ and NO_x emissions.

The market model used to forecast purchase power prices reflects the assumption that either 32 GW or 65 GW of coal capacity will be replaced nationwide by 2020. It was assumed that utilities in the eastern interconnection will find a way to preserve this capacity in such a way as to avoid loss of CSAPR allowances after four years of not operating (i.e., fuel conversion or limited operation).

The current Wisconsin RPS (10% renewable by 2015) was assumed.

B.4 PLANNING FUTURES

The following chart shows the planning futures assumed for this study. These futures were approved by the WPS Electric Planning Committee (EPC) on February 1st. The most notable change relative to the 2011 approved futures is the assumption that 32 GW or 65 GW of coal will be replaced in all futures. Also, the CO₂ adder is assumed in two of the three futures. SO₂ and NO_x dispatch adders are assumed as a result of CSAPR.

**WPSC Planning Futures For Spring 2012 Planning Studies
February 2012**

Study Future:**Future 1****Future 2****Future 3**

Base Fuels

High Gas
& CO2Low Fuels
CO2 & High Load**Parameters:**

U.S. Coal Unit Retirements by 2020

32 GW

65 GW

65 GW

Natural Gas Price

Base

High

Low

Coal Price

Base

Base

Low

SO2 and NOx Prices

Base

Low

Low

Load Growth

Base

Base

High

CO2 Price

\$0/ton

\$20/ton in 2022

\$20/ton in 2022

Target one year capacity purchase (50
Mw increments) - MW0 Mw 2014 -
2023, up to 300
Mw 2024++0 Mw 2014 -
2023, up to 300
Mw 2024++0 Mw 2014 -
2023, up to 300
Mw 2024++

* Future 1 will include sensitivity looking at WPS low load to address energy efficiency.

[illegible]

B.5 COMPLIANCE OPTIONS

Plans were developed from a subset of options that result in SO₂ and NO_x emissions being lower than the forecasted allowance budget.

The following compliance options were considered:

Compliance Option	SO ₂	NO _x
Weston 3		
Replace unit (Base Case Assumption)	X	X
ReACT for SO ₂ and NO _x control	X	X
Dry FGD/SCR	X	X
[REDACTED]		
[REDACTED]	X	
[REDACTED]	X	X
[REDACTED]		
[REDACTED]	X	X
[REDACTED]	X	X
[REDACTED]		
[REDACTED]	X	X
[REDACTED]	X	X

The study reflects the CSAPR requirement that four years after a WPS unit no longer operates WPS will not receive the allowances associated with the idled unit. This means that plans that include unit replacements will also result in lower allowances in later years. As the value of allowances increases, this assumption favors investment in controls.

B.6 COMPLIANCE STRATEGIES

The compliance options were combined to create compliance plans that reflect the following compliance strategies. The least cost strategy was determined subject to an assessment of risk associated with the compliance strategy.

- A. Emission control compliance-Investment in emission controls.
- B. Unit replacement compliance-Replace existing coal units instead of investment in emission controls.
- C. Small unit operation compliance-Determine asset value of Pulliam 5&6 and Weston 1&2 as coal units. Determine if asset value would support continued operation as coal units.
- D. Fuel conversion-Modify operation of existing generating assets to preserve capacity credit and comply with CSAPR without depending on allowance purchases.
- E. Allowance purchase compliance up to the assurance cap in CSAPR-Purchase of allowances up to 18 percent of SO₂ and 21 percent of NO_x allowance budgets.

B.7 EXPANSION PLANS

The assessment of compliance strategies requires a robust analysis of complimentary expansion plans (new unit additions to maintain reserve margin). **Exhibit 15** contains a listing of new unit technical and cost parameters that were evaluated in the optimization of the new unit expansion plans.

B.8 METHODOLOGY

- A. EGEAS was used to identify the least cost expansion plan for those compliance strategies that result in different unit replacement dates. EGEAS was also used to determine the least cost compliance plan for the WPS requirements customers.
- B. The Strategic Planning (MIDAS) model was used to simulate the level of risk associated with the compliance plans being considered. This incorporates opportunity sales for both energy and capacity to more closely simulate the MISO market and is referred to as the Market Risk Analysis in this report. The MIDAS model also has the capability to simulate a control area similar to EGEAS for the WPS requirements customer. This was done to benchmark the economics of both models on the same platform.
- C. A sensitivity analysis was completed due to the fact there is uncertainty associated with some of the alternatives.

B.9 RESULTS

- A. The Reference Plan

In order to assess specific compliance options for Weston Unit 3 a CSAPR compliance plan for Pulliam and Weston Units 1&2 needed to be developed. The planning analysis summary shows:

1. Continuing to operate Weston Units 1&2 and Pulliam Units 5&6 as coal fuelled units results in WPS not complying with CSAPR in the long term and the present value revenue requirement savings associated with continued operation on coal will not support capital investments needed to maintain compliance.
2. Converting Weston Units 1&2 and Pulliam Units 5&6 to natural gas operation results in reduced SO₂ and NO_x emissions and is a cost effective compliance option due to the value of generating capacity in the 2014 – 2022 time frame.
3. Continuing to operate Pulliam Units 7&8 as coal fuelled units with a \$79 million capital investment in DSI, fabric filter and cooling tower to assure compliance results in cost effective compliance (when risk is taken into account) with CSAPR. Continued operation of Pulliam Units 7&8 as coal fuelled units also helps to allow the continued operation of Pulliam Units 5&6 on natural gas due to staffing levels for Pulliam Units 7&8.
4. Continuing to operate Pulliam Units 5&6 on natural gas and Pulliam Units 7&8 as coal fuelled units provides approximately 333 Mw of capacity [REDACTED].

The Reference Plan consists of converting Weston Units 1&2 and Pulliam Units 5&6 to natural gas operation while continuing to invest in environmental controls for Pulliam Units 7&8 so that those units can continue to operate as coal fuelled units.

[REDACTED]

B. Weston Unit 3 Compliance Options

There are three compliance options for Weston Unit 3 that will assure compliance with Phase 2 of CSAPR. These options are also expected to meet the likely emission limits resulting from a resolution of the EPA NOV.

1. Retire Weston Unit 3 after 12/2016, the base case assumption.
2. Install ReACT on Weston Unit 3 by 12/2016
3. Install a dry FGD/SCR on Weston Unit 3 by 12/2016

The present value revenue requirement (PVRR) analyses were done using both the EGEAS model (point forecast) and Market Risk Analysis model (distribution of results) for the three planning futures under consideration. The economic analysis compares the life cycle PVRR of emission controls to replacement of Weston Unit 3 after 12/2016. A negative delta PVRR value means the emission control option reduces PVRR relative to the Weston Unit 3 replacement after 12/2016.

PUBLIC VERSION

EGEAS Study in PVRR Results in Millions \$
Weston 3 Compliance Options:
Install Emission Controls minus Replace Weston 3 12/2016

Compliance Options: Reference Plan	Future 1	Future 2	Future 3
PVRR: Replace Weston 3 12/2016	\$11,694	\$14,828	\$13,016
PVRR: Install ReACT in 12/2016	\$11,401	\$14,572	\$13,031
PVRR: Install Dry FGD/SCR	\$11,561	\$14,732	\$13,177
Delta PVRR: ReACT vs. Replace	-\$293	-\$257	\$16
Delta PVRR: Dry FGD/SCR vs. Replace	-\$133	-\$96	\$161

[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

Compliance Options: Reference Plan (Low Load Forecast)	Future 1
PVRR: Replace Weston 3 12/2016	\$11,077
PVRR: Install ReACT in 12/2016	\$10,801
Delta PVRR: ReACT vs. Replace	-\$276

MIDAS Risk Assessment Delta PVRR Results in Millions \$
Emission Control Option minus Weston Unit 3 Replacement after 12/2016
90% Probability Range

Reference Plan	Future 1	Future 2	Future 3
Delta PVRR: ReACT vs. Replace Weston 3	-\$295 to -\$166	-\$337 to -\$44	-\$37 to \$98
Delta PVRR: Dry FGD/SCR vs. Replace Weston 3	-\$137 to -\$11	-\$178 to \$106	\$112 to \$242

Reference Plan: Low Load Forecast	Future 1
Delta PVRR: ReACT vs. Replace Weston 3	-\$353 to -\$184

C. Comparison of Control Technologies

Between the ReACT and the dry FGD technologies for meeting Weston Unit 3 emission limits required by CSAPR and/or a resolution of the EPA NOV, the ReACT control option is preferred because it can achieve NO_x reductions that the dry FGD system alone cannot achieve. The ReACT system can achieve substantial NO_x reductions by injecting additional reagents. By contrast, in order to achieve similar NO_x reductions, the dry FGD control system would require the installation of an SCR. The value of the ReACT compliance option is quantified in the following tables by comparing the change in PVRR between the ReACT control option and the dry FGD/SCR control option.

**EGEAS Study PVRR Results in Millions \$
ReACT versus Dry FGD/SCR**

Compliance Option	Future 1	Future 2	Future 3
Install ReACT in 12/2016	\$11,401	\$14,572	\$13,031
Install Dry FGD and SCR in 12/2016	\$11,561	\$14,732	\$13,177
ReACT Value (Delta PVRR): Dry FGD & SCR minus ReACT	\$160	\$160	\$146

**Midas Risk Assessment PVRR Results in Millions \$
for ReACT Compliance Value
90% Probability Range**

Compliance Option	Future 1	Future 2	Future 3
ReACT Value (Delta PVRR): Dry FGD & SCR minus ReACT	\$155 to \$159	\$151 to \$160	\$144 to \$149

D. Detailed Study Results

Exhibits 1-12 include Life Cycle PVRR Results and delta annual revenue requirement results for the compliance options of interest in the three planning futures. Exhibits 30-47 include expansion plans, forecasted emissions and energy sources.

B.10 CONCLUSIONS

For Weston Unit 3's compliance with CSAPR, a similar replacement regulation and/or a resolution of the EPA NOV, in two of the three planning futures (Futures 1&2) this study confirms that installing ReACT on Weston Unit 3 results in substantial reductions in PVRR when compared to the compliance option of replacing Weston Unit 3 after 12/2016.

Future 3 assumes low fuel prices and a CO₂ adder and provides the strongest economic argument for replacing coal units rather than investing in emission controls to achieve emission reductions. Even in that future, the economics of investing in ReACT for Weston Unit 3 is comparable to the economics of replacing Weston Unit 3 after 12/2016.

In Futures 1&2 installing ReACT compared to replacing Weston Unit 3 after 12/2016 results in the same level of substantial reductions in PVRR for the following changes in Reference Plan assumptions (original Reference Plan assumptions: base load forecast with [REDACTED])

Base load forecast with [REDACTED]

Low load forecast with [REDACTED]

The economics of ReACT are independent of how [REDACTED] A lower load forecast does not materially change the economics of ReACT compared to replacing Weston Unit 3 after 12/2016.

ReACT is a superior compliance option compared to the dry FGD control option . ReACT has the ability to provide NO_x reductions by increasing reagent injection into the ReACT control system. The dry FGD system requires the installation of a SCR system to provide NO_x reductions. The dry FGD/SCR increases PVRR by approximately \$144 - \$160 million compared to the ReACT system.

APPENDIX C

TECHNOLOGY ALTERNATIVES - Emissions Reduction Technology Selection

C.1 TECHNOLOGY PROCESSES

Weston Unit 3 currently has LNB and OFA for NO_x control, ACI for mercury control, and a fabric filter for particulate control. The unit burns low-sulfur PRB fuel as part of its existing compliance strategy. Pending federal regulations are likely to require further emission reductions for Weston Unit 3.

The specific technologies chosen to accomplish the goal of SO₂ and additional NO_x emission reductions at Weston Unit 3 was determined by an analysis of the following parameters:

- Technologies capable of meeting the requirements of current and probable future regulations discussed in **Section 3** of this Application.
- Available and proven technologies for emission reductions at units of comparable or larger size.
- Capability of technology to meet strict surface water mercury discharge standards or achieve zero liquid discharge.
- Technology and fuel compatibility.
- Reliable, long-term removal efficiencies achievable by each technology.
- Co-benefits and synergistic effects of multiple technologies for maximum multi-pollutant emission controls, notably SO₂, NO_x and mercury.
- Specific costs for each technology at Weston Unit 3.
- Implementation timeframes, especially lead times and availability of critical components.
- Plant specific considerations (e.g. space or current plant equipment constraints).

Capturing mercury from the flue gas produced by electric generating units (EGUs) is a relatively new area of technology development. Despite the significant advancements made in the last several years, long-term removal efficiencies have not been established for many of the technologies under development. ACI was previously installed on Weston Unit 3 upstream of the existing fabric filters for mercury reduction. The analysis at Weston considered the co-benefit impacts on mercury control of the selected technologies for SO₂ and NO_x control.

There are many processes that have been developed over the last several decades to scrub SO₂ from power plant flue gas emissions. These technologies represent a wide variety of sorbent types, process configurations and removal mechanisms; however, many of these technologies do not meet the criteria of being commercially available and proven technologies. Based on site requirements and the evaluation criteria listed above, the following technologies were evaluated for SO₂ emissions reduction:

- Wet FGD, Limestone with Forced Oxidation
- Dry FGD, Spray Dryer Absorber
- Dry FGD, Circulating Fluidized Bed
- Dry Sorbent Injection
- Multi-Pollutant, Regenerative AC (ReACT)

These technologies chosen for further analysis represent wet and dry FGD technologies and are among the most widely used in the electric utility industry for SO₂ emissions control. Wet FGD is assumed to use LSFO. There are several different absorber designs offered by wet FGD vendors, but operating performance is similar for all of them; therefore, a generic open spray tower is assumed for this analysis. Dry FGD technologies can use either an SDA or CDS absorber, both of which use a lime reagent to remove SO₂ from the flue gas. Both dry technologies require a downstream particulate control device, usually a fabric filter, to accumulate the reaction products, unused reagent, and fly ash for proper disposal. The ReACT process is based on the use of a moving bed of AC pellets with the flue gas passing horizontally through the moving bed, adsorbing SO₂, SO₃, and mercury while reducing NO_x through a catalytic reaction with ammonia within the AC bed.

The technologies available for NO_x control on coal-fired boilers are well established and fall into two categories: combustion modifications and post-combustion controls. The combustion modification options include LNB and OFA (close-coupled and separated), which rely upon staging the combustion air and reducing the temperature of the flame that reduces the amount of NO_x produced during the combustion process. Controlling NO_x emissions by use of combustion process control has already been implemented on Weston Unit 3.

The post-combustion controls include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) and rely on the use of ammonia or urea to react with the NO_x to reduce it to nitrogen gas and water. Based on site requirements and the evaluation criteria listed above, the following technologies were evaluated for NO_x emissions reduction:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Multi-Pollutant, (ReACT)

C.2 EVALUATED FGD TECHNOLOGIES

C.2.1 Limestone Forced Oxidation

The LSFO system has many aspects to its design and operation that initially recommended it for consideration at Weston Unit 3, including:

- LSFO was one of the first technologies developed to remove SO₂ from boiler flue gas and is currently the most commonly used technology.
- The electric utility industry has vast experience with LSFO.
- Vessel designs have advanced over the past 5-10 years, and a single vessel capable of treating 1,000 MW of flue gas has been demonstrated with high reliability.
- Vendors are guaranteeing performance of a +97% SO₂ removal.
- LSFO has demonstrated high SO₂ removal efficiency across a broad range of fuels and flue gas flow rates.
- Limestone has a lower reagent cost than lime reagent.
- Gypsum by-product can be beneficially reused.

Further analyses of the LSFO system, including its impact on plant operations and other environmental considerations, are discussed in the following sections.

Particulate Emissions

The LSFO system would be installed downstream of the existing fabric filters on Weston Unit 3. Operation of the LSFO system would not affect the performance of the Particulate control system. As shown in **Figure C.1**, fabric filters are effective at capturing particulates across the entire range of fly ash particulate size distribution.

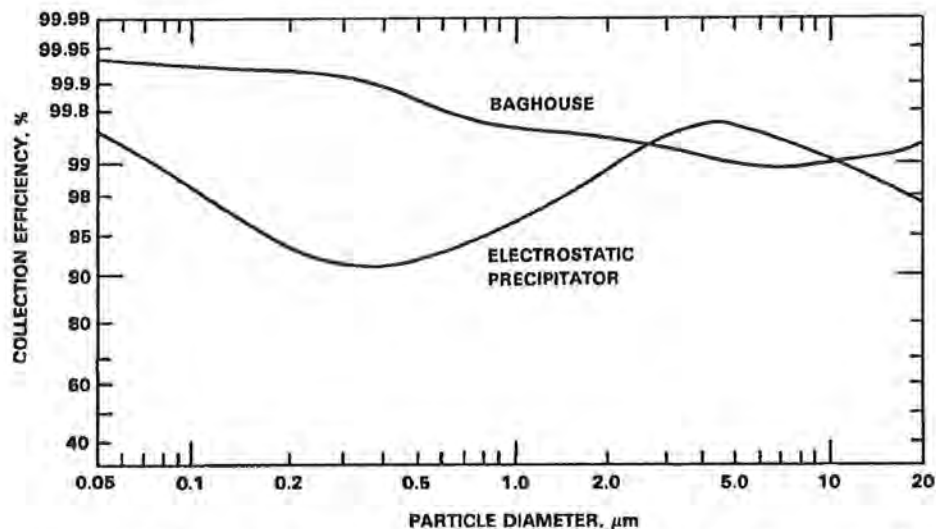


Figure C.1 Particle Diameter Effect on Collection Efficiency for a Fabric Filter and ESP²

Mercury

An LSFO system can achieve up to 90% removal of oxidized mercury, while elemental mercury will pass through the scrubber vessel. The oxidized mercury ends up in the LSFO liquor, which then partitions between the gypsum and effluent water during the dewatering process. The mercury in the effluent water can be removed in a standard physical/chemical wastewater treatment process in which most of the mercury ends up in the sludge. However, some mercury will remain in the wastewater discharge stream. Recent testing demonstrated that mercury captured in the wet FGD liquor can react to form more elemental mercury and be reemitted with the exiting flue gas. Additives and instrumentation have been developed to reduce this potential for reemission. PRB fuel has very little oxidized mercury. The use of fuel additives to oxidize additional mercury in the coal, subsequently achieving greater overall mercury reduction across a wet scrubber, has been demonstrated commercially, but not over a long time period.

Wastewater Treatment/Discharge

The LSFO wastewater stream will need to be treated to maintain proper operation of the system as well as to meet discharge standards, especially for mercury. As stated above, an LSFO system will capture up to 90% of the oxidized mercury present in the flue gas. When the gypsum by-product is dewatered, a portion of the mercury will be retained in the gypsum solids and associated moisture content, with the remainder in the effluent from the dewatering process.

² "Baghouses for the Electric Utility Industry, Volume 1"; EPRI Publication No. CS-5161; prepared by Southern Research Institute; 1988 pg. 1-4.

Mercury concentrations in the effluent water will depend on the amount of oxidized mercury in the flue gas and the blow down rate. If a fuel additive is used to increase the amount of oxidized mercury in the flue gas, as would be needed at Weston Unit 3 to approach 90% mercury removal, then the concentration of mercury in the effluent water will likely be higher without extensive treatment.

The Wisconsin Department of Natural Resources (WDNR) has designated the Wisconsin River as being mercury impaired and has established strict prohibitions on the mercury levels in any wastewater discharge to mercury impaired surface waters. Any effluent would have to be treated before being discharged, requiring the additional cost of a wastewater treatment facility. There are limited commercial alternatives and therefore, WPS eliminated the Wet FGD from further consideration.

Other Operating Considerations

The following are additional operating considerations of an LSFO system:

- Water requirement – LSFO is a wet FGD system that by definition lowers the flue gas temperature within the absorber vessel to the saturation point (co-existence of vapor and liquid phase of water), typically around 130°F. Water is used to cool the flue gas to the saturation temperature primarily through evaporation; therefore, an LSFO system will have a higher water usage rate than a dry FGD system that does not require fully saturated flue gas.
- Stack Plume Visibility – since the flue gas is saturated when it exits the LSFO absorber vessel, a heavy steam plume will be visible at the stack exit during all ambient conditions due to the lower temperature of the flue gas. The steam plume will also have less buoyancy than higher temperature stack gases, resulting in a tendency to fold downward as it exits the stack. Reheat systems have been used in the past to maintain dry stack conditions; however, they are very expensive to operate and have a negative effect on the plant heat rate. Additional plume visibility can result from condensable particulate matter such as sulfuric acid mist, which is generated when SO₃ produced during coal combustion combines with water vapor in the flue gas and then is cooled below the sulfuric acid dew point. Wet FGD systems typically remove 30% or less of the inlet SO₃/acid mist; the remainder can result in an acid mist plume exiting the stack. For the low sulfur coal conditions at Weston 3, and the high alkalinity of the PRB coal ash, this acid mist plume may not be a significant issue.
- Stack – due to the saturated and acidic nature of the flue gas, a new chimney would need to be constructed (adding cost to the installation of an LSFO system) to prevent corrosion of the chimney liner and to meet stack exit velocity requirements.
- Power Requirements – an LSFO system will have a higher auxiliary power requirement than a dry system. A large portion of the power requirement is due to the multiple large liquid recycle pumps necessary to recycle the limestone slurry within the absorber to achieve good gas-to-liquid contact and efficient SO₂ removal.
- Maintenance – The operating and maintenance requirements for a wet FGD system are significantly higher than a dry FGD system due to the large recycle pumps and need for dewatering equipment.

C.2.2 Spray Dryer Absorber

Spray dryer absorbers are best suited for power generating units 600 MW or less that fire low sulfur coals, such as the PRB coal used at Weston Unit 3. The SDA system is typically used to scrub coals with a maximum sulfur content of 1.5 % weight sulfur. The SDA system has the ability to maintain approximately 90-94% SO₂ removal on a long term average basis. The sulfur content of PRB coal can range as high as 0.80% by weight, which is within the operational range of the SDA system. The SDA vessels are limited to treating approximately 300 MW of flue gas in a single vessel; therefore, two vessels would likely be necessary for an installation at Weston Unit 3. There is no market at this time for the beneficial reuse of the SDA by-product, which is a mixture of calcium salts, unused reagent and fly ash.

Further analysis of the SDA system including the impact of such a system on Weston Unit 3 operations and other environmental impacts are discussed in the following sections.

Particulate Emissions

The installation of an SDA for SO₂ control requires the operation of a downstream particulate control device to capture the reaction products from the SDA vessel. Weston Unit 3 already has a fabric filter that can be used to collect the SDA reaction products. The location of the existing fabric filters complicates the ductwork arrangement and results in increased pressure drop through the system.

Mercury

The operation of the SDA and fabric filter system has some amount of native mercury capture associated with it, although the capture efficiency is very low for the un-oxidized mercury species typically created during the firing of PRB coal. The real benefit of the SDA and fabric filter system for mercury removal comes from using the system in conjunction with ACI upstream of the SDA vessel. The benefit of such an arrangement is two-fold: (1) injection of the activated carbon upstream of the SDA provides a long residence time for the carbon to mix and react with the mercury in the flue gas prior to collection in the fabric filters; (2) the filter cake that builds up on the fabric filters provides additional reaction surface for greater mercury removal.

Wastewater Treatment

The SDA process is considered a semi-dry process. Water, introduced into the system via lime slurry and dilution water, is used to aid in the reaction between the lime and flue gas SO₂. The evaporation of water in the lime slurry controls the temperature of flue gas at the outlet of the SDA. All water introduced into the SDA vessel is evaporated upon contact with the hot flue gas and exits the system with the flue gas as vapor. The only waste stream from the SDA/FF system is the dry solid waste stream, the majority of which is collected in the fabric filters. A small amount of dry solids is collected at the bottom of the SDA vessel. The dry solid waste eliminates the added expense of a wastewater treatment system as well as the concern of mercury and other regulated contaminants in the discharge to surface waters.

Other Operating Considerations

- Water – An SDA consumes less water than a wet FGD system because the flue gas is cooled to approximately 30 degrees above the saturation temperature.

- **Stack Plume Visibility** – Because the flue gas exiting the stack is unsaturated, a steam plume may not be visible under some atmospheric conditions. However, when ambient temperatures are low enough, a steam plume from a dry scrubber can also appear. Other condensable particulate matter such as sulfuric acid mist, which is produced by the combination of SO_3 generated during combustion and water vapor present in the flue gas, can lead to a visible plume from the stack. Dry FGD systems are capable of reducing acid mist by +98%, thereby virtually eliminating any potential for a visible acid mist plume.
- **Stack** – the existing stack can be reused because the flue gas is not saturated; therefore, corrosion and exit velocity are not major concerns. No Stack modifications are included in the capital cost for the SDA system.
- **Power Requirements** – A dry FGD system consisting of an SDA and fabric filters consume less auxiliary power than a wet FGD system. Although an SDA and fabric filters have a higher pressure drops than a wet FGD system alone due primarily to the fabric filters, the increase in fan power required to overcome this pressure drop is more than offset by the large recycle pumps required by a wet system. And at Weston 3, the fabric filter is already in service.
- **Maintenance** – the dry by-product from the SDA can be handled by conventional fly ash systems, resulting in the elimination of dewatering equipment and a reduction in the associated maintenance. Maintenance requirements are further decreased due to the elimination of large recycle pumps.

C.2.3 Circulating Dry Scrubber

The (CDS) absorber system is another dry FGD technology that was considered for control of SO_2 emissions on Weston Unit 3. A CDS system has many of the same advantages of an SDA over a wet FGD system, such as:

- High mercury removal efficiency with ACI.
- No wastewater treatment required.
- Greater removal of $\text{PM}_{2.5}$ with the operation of fabric filters.
- If new fabric filters are installed downstream of the CDS absorbers, then the plant could preserve the beneficial reuse of fly ash.
- Lower auxiliary power consumption.
- Less equipment installed resulting in an easier system to operate and maintain.
- Cheaper materials of construction.

In some cases the CDS may be chosen over the SDA technology due to the following characteristics of the CDS:

- A CDS can typically handle higher inlet concentrations of SO_2 and maintain higher reduction efficiencies than the SDA especially where coal composition is expected to change over the operating life of the system.
- A CDS is simpler to operate than an SDA because rotary atomizers are not required, eliminating a major piece of rotating equipment. Additionally, the hydrated lime reagent is injected into the reactor dry, eliminating slurry preparation equipment and potential plugging issues.
- A CDS generally requires lower reagent feed rates resulting in lower operating costs and less solid waste while achieving higher SO_2 removal efficiencies.

The most significant drawback to a CDS is that the absorber vessels are typically limited to 150-200 MW although some vendors are developing vessels large enough for 300 MW of flue gas.

There are only a few large boiler installations operating with CDS FGD systems, and the experience base for CDS FGD systems operating on PRB coal-fired boilers is very limited.

Additional drawbacks to the CDS system are:

- A CDS has a higher pressure drop across the absorber vessel, resulting in a higher parasitic load.
- The CDS is not flexible at handling varying unit loads, such as would be the case at Weston Unit 3. The CDS requires a minimum gas flow rate to maintain the fluidized nature of the bed. If the unit load drops below this minimum, a gas recycle system is required to maintain performance of the bed. The gas recycle can add significant expense and complexity to the system.
- The fabric filters downstream of the CDS are typically designed with a lower air-to-cloth ratio resulting in fabric filters with a larger footprint than would be found downstream of an SDA. The operating temperature for the CDS is also higher than that of the SDA, further increasing the size of the fabric filters in the CDS case.
- A new CDS FGD installation typically requires that the fabric filters be elevated to allow recycle of the collected solids via air slides. This will increase the structural steel and foundation costs of the fabric filters.
- There is no market for the beneficial reuse of the CDS by-product mixture of calcium salts, unused reagent, and fly ash.

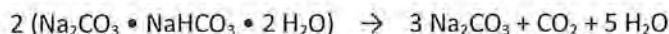
C.2.4 Dry Sorbent Injection (DSI) System

The Dry Sorbent Injection technology has been available for commercial application to utility SO₂ control since the 1980s based on initial testing in the 1970s. Highly reactive sodium compounds, including Trona (naturally occurring sodium sesquicarbonate – Na₂CO₃ • NaHCO₃ • 2H₂O), sodium bicarbonate, and Nahcolite (a naturally occurring sodium bicarbonate) have all been used for FGD applications in multiple demonstration programs at power generation facilities. The delivered cost of these reagents and their relatively high reagent feed rate required to achieve moderate levels of SO₂ reduction, along with the solubility of the waste solids produced, have limited their application to only a few plants in the U.S. However, in the current regulatory environment, and given the age of many of the smaller units that are now faced with SO₂ emissions regulations, the relatively low capital investment required for DSI system installations has increased the level of interest in these systems.

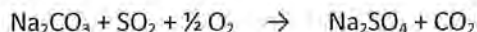
The technology is simple - a storage silo is required to receive the reagent at the site, a pneumatic conveying system moves the solids from the silo to the mill and then to the injection grid typically located upstream of the air heater. The injection rates required for SO₂ reductions above 50-65% will likely require a fabric filter to both handle the larger solids loading in the flue gas, as well as to provide additional contact time for increased SO₂ removal. The dry solid waste mixture is then removed from the particulate collector hoppers and stored temporarily in silos before transfer to the final disposal site. The sodium salts in this mixed waste (unreacted sodium reagent, fly ash and reaction products) will be highly soluble in water. This may require an existing landfill area to modify its operating procedures (potentially provide encapsulation of the waste material and/or to install a new liner and leachate collection system for the area handling the DSI waste, and then confirm the ability to handle the leachate that can have a higher pH and larger concentrations of sodium compounds).

Data in the literature indicates that sodium concentrations in the DSI waste can increase by more than a factor of 10-20 compared to the initial concentration in the fly ash. The basic process chemistry is outlined by the following reactions when using Trona:

Decomposition:



Absorption Reaction:



Refined sodium carbonate was found in earlier testing to not be an acceptable reagent for FGD applications, possibly because it does not undergo the decomposition reaction that increases porosity and available surface area for reaction with the SO_2 .

Unit Operations/Modifications

- | | | |
|---|---|---|
| 1 Sensitive to proper reagent distribution and residence time in the flue gas duct. | May require longer duct runs and more injection points to attain proper distribution and residence time. | Higher capital cost.

General Arrangement issues. |
| 2 Low load flue gas temperatures may not be sufficient for required SO_2 removal | <p>Flue gas temperature at point of injection should be above 290°F.</p> <p>Injection upstream or mid air heater may be required or an AH bypass might be required.</p> | <p>Increase minimum MW operation, resulting in higher fuel costs and dispatching issues.</p> <p>Potential process complications and cost impacts if injecting upstream or mid air heater.</p> <p>Higher capital cost and heat rate impact if bypass is installed to maintain current load swings with injection downstream of AH.</p> <p>Loss of unit efficiency if AH bypass is installed. Expected heat rate impact is in the order of 2-4 %.</p> |

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|--|---|---|
| 3 Steam soot blowing | May have an adverse effect on product material coating bags since the byproduct is sensitive to water. | Potential for increasing fabric filter pressure drop, solids disengagement and/or material handling issues.

May consider some supplemental cleaning system such as sonic air horns to mitigate pressure drop increase across FF. Higher capital cost. |
| 4 Ammonium Bisulfate (ABS) formation at low temperatures may affect fabric filter. | ABS formation has been reported in air heater. This can be an issue for any downstream fabric filter system (including calcium-based).

There is limited data available regarding the sensitivity of sodium vs. calcium-based systems to ABS reaching the bags. | Potential for increasing fabric filter pressure drop, solids disengagement and/or material handling issues.

May require supplemental reagent injection upstream of the air heater to eliminate SO ₃ even if downstream injection can achieve the required SO ₂ removal efficiency. |

Disposal of Sodium Waste

1. Sodium salts are soluble and dissolve in water.	Sodium salt landfill permeate and runoff is expected to have high dissolved metals.	Requires liners and special handling at landfill, including the possibility of runoff water treatment.
	Sulfite/sulfates have the potential to reduce down to H ₂ S given the proper anaerobic conditions.	May have to segregate from calcium based waste products in the landfill. Landfill cells holding sodium salts may have to be encapsulated. Higher capital and operating costs.

C.2.5 Multi-Pollutant Flue Gas Desulfurization-ReACT

The ReACT process utilizes a moving bed of AC with ammonia injection to simultaneously remove SO₂, NO_x, and mercury from the flue gas. Spent AC from the adsorption process is regenerated and recycled back to the adsorber, while sulfur-rich gas (SRG) is sent to a by-product recovery unit and processed into a saleable sulfuric acid or gypsum by-product.

In the adsorption step of the process, ammonia is injected into the flue gas, which then passes through an adsorption tower containing a moving bed of ½" diameter AC pellets. The pellets move downward through the bed while flue gas flows horizontally through the pellet bed. SO₂ in the flue gas reacts with oxygen, water, and ammonia to form various compounds that are adsorbed onto the surface of the AC. The ReACT process removes SO₂ by an adsorption reaction with water vapor and oxygen.

The SO₂ saturated AC is conveyed to a regenerator vessel, where the AC is thermally regenerated by indirect heating. The SRG (22-25% SO₂ by volume) produced in the regenerator is then sent to a by-product recovery unit where it is further processed to form sulfuric acid using conventional methods.

Particulate Emissions

The Weston Unit 3 ReACT installation will be downstream of the existing fabric filters and will not be required to remove particulate matter from the flue gas stream. However, the system supplier claims that the adsorber also acts as a particulate control device and can maintain particulate emissions below 0.015 lb/MMBtu. This means that the system could provide additional reductions in particulate emissions.

NO_x

The NO_x in the flue gas is catalytically reduced to nitrogen and water on the surface of the AC by reaction with ammonia injected into the flue gas upstream of the AC bed. Further NO_x reductions can occur with additional ammonia injection in the regenerator.

Mercury

Mercury in the flue gas is removed by adsorption onto the surface of the activated AC in the presence of SO₂, regardless of speciation and chlorine content in the flue gas. The adsorbed mercury desorbs from the AC during the regeneration process, but is re-adsorbed again in the upper section of the regenerator where the temperature is cooler. The mercury, therefore, accumulates on the AC in the regenerator. As a result, a portion of the AC needs to be extracted from the process every few years depending on the mercury concentration in the coal.

Wastewater

The ReACT removal process is a dry process and requires no water except for the processing of the SO₂-rich by-product stream to produce sulfuric acid. The sulfuric acid by-product will also require cooling water to control the exothermic reaction.

Other Operating Considerations

- Preservation of the beneficial reuse of fly ash and savings from the reduced or eliminated use of ACl because the ReACT AC reagent removes mercury from flue gas.
- Co-benefited NO_x removal means that a separate technology does not have to be installed to reduce NO_x emissions.
- Salable sulfuric acid by-product, although the sale price is subject to market volatility. Additionally, the sulfuric acid plant is similar to operating a chemical plant on-site.
- Limited water consumption - The ReACT system operates at air heater outlet temperatures and, therefore, does not require any water for flue gas cooling/humidification.
- Cheaper materials of construction.
- No wastewater treatment required.
- The existing stack can be used.

C.3 EVALUATED NO_x TECHNOLOGIES

C.3.1 Selective Catalytic Reduction (SCR)

SCR utilizes a nitrogen-based reducing agent, such as urea or ammonia, to reduce flue gas NO_x to molecular nitrogen (N₂) and water vapor (H₂O). The SCR process employs a metal-based catalyst to increase the rate of the reduction reaction, resulting in a higher NO_x removal efficiency within a lower and broader temperature window than is possible for a non-catalyzed process. The NO_x reduction reactions occur as the flue gas passes through the catalyst chamber. Ammonia is injected into the flue gas downstream of the furnace economizer through an injection grid mounted in the ductwork. The reagent is typically diluted with compressed air or steam to aid in

injection, and is injected at sufficient distance upstream of the catalyst chamber to allow for adequate mixing of the reagent and flue gas. The hot flue gas and reagent then flow into the catalyst, where NO_x in the flue gas chemically reduces into nitrogen and water. The nitrogen, water, and other flue gas constituents then flow out of the SCR reactor.

The SCR process has demonstrated removal efficiencies of 70-90% NO_x at utility boiler installations firing PRB and other coals at NO_x inlet concentrations of 0.4 lbs/MMBtu.

C.3.2 Selective Non-catalytic Reduction (SNCR)

SNCR utilizes a nitrogen-based reducing agent, such as urea or ammonia, to reduce flue gas NO_x to molecular nitrogen (N_2) and water vapor (H_2O). The reactions occur within the combustion unit, which acts as a reaction chamber for the SNCR process. Ammonia or urea reagent is injected into the boiler interior in the post-combustion, upper area of the furnace, and the convective passes. Upon injection, the reagent mixes with the flue gas. The heat of the boiler then provides energy for the reduction reaction of NO_x to nitrogen and water vapor to occur. The reacted flue gas then flows out of the reactor. Both ammonia and urea have been successfully employed as reagents in the SNCR process. The major difference between the ammonia and urea processes is that ammonia is typically injected into the flue gas in a gaseous state, while urea is injected as an aqueous solution. The acceptable temperature range for either reaction is 1400 to 2000°F, with temperatures above 1700°F preferred. Above 2000°F, ammonia and urea can react with oxygen in the flue gas to form additional NO_x .

The SNCR process has demonstrated NO_x removal efficiencies of 10-70% depending upon the boiler NO_x levels and operating conditions (temperature, residence time, load stability, etc). As was previously mentioned, an SNCR system installed at Weston Unit 3 would likely be limited to 10-15% NO_x reduction. Application of a SNCR does not result in an emission control system that has comparable NO_x emission performance to a ReACT system.

C.3.3 ReACT

The NO_x in the flue gas is catalytically reduced to nitrogen and water by reaction with ammonia in the AC bed and reducing compounds on the surface of the AC. ReACT has demonstrated reductions of SO_2 and mercury with the co-benefit of NO_x reductions.

APPENDIX D

PROJECT CONCEPTUAL DESIGN SCOPE ASSUMPTIONS

General Project Estimate	
Project Description	Retrofit multi-pollutant flue gas desulfurization (ReACT) to reduce SO ₂ emissions and associated multi-pollutant co-benefits (namely NO _x and mercury).
Plant	Weston Unit 3 has a PC Tangential Balanced Draft Boiler
Design Fuel	PRB coal (with highest anticipated sulfur content). 8150 Btu/lb, 30% moisture, 7.5 % ash and maximum sulfur of .50%
Operation	Load Following with swings 150 to 360 gross MW
Capacity Factor	81%
Minimum Load Capacity	40%
Project Location	Weston Plant located near Wausau in Marathon County, WI
Site Description	Brownfield- existing Units 1,2 & 4 share the same site at Weston
Boiler Manufacturer	CE/ Alstom Power
Project Commissioning and Start-up Date	1981
Cost Basis / Assumptions	
General	
Ammonia Supply (29% aqueous)	
Source	29% aqueous ammonia anticipated from Hydrite Chemical Co., present 19% ammonia supplier for Weston site.
Delivery	25 Ton stainless steel tank trucks are unloaded via skid mounted unloading pumps. Ammonia forwarding pumps transfer liquid ammonia from storage tanks to vaporization and dilution equipment prior to being injected into the flue gas.
Storage and Preparation	Bulk ammonia storage tanks installed on concrete foundations with concrete containment surrounding the tanks and located in a remote location away from other personnel activities.
AAC Supply	
Source	AC manufacturer is Calgon Carbon Japan (CCJ) via manufacturing plant in Taiyuan, China. Plant manufactures and packages into metric ton sized super sacs.
Delivery	At port city of Tianjin, China, super sacs loaded onto intermodal containers for shipment to US. HRC takes ownership of material prior to departure. Product is shipped via rail and truck to HRC storage facility located in the Chicago area, where a minimum of 3 month supply will be maintained for Weston Unit 3 use.
Storage and Preparation	Super sacs will be unloaded into bulk dump trucks for delivery to Weston area facility. When on site, product is unloaded into 300 ton storage located in ReACT process island.
Sulfuric Acid By-Product (93-98%)	
Storage and Preparation	On site sulfuric acid plant will transport final product to bulk sulfuric acid storage tank (10-day capacity would be ideal for potential local marketer). This tank would be installed on concrete foundation and would include containment area for potential spills.

PUBLIC VERSION

Delivery	Acid forwarding pump transfers acid from storage tank to transport trucks. Liquid bulk tank truck having capacities of about 3200 gallons will be loaded onsite and transported to end user.
Destination	It is anticipated that Midwest sulfuric acid marketer will be used to distribute the acid product to end users.
Civil	
Site Conditions	Adequate space to install additional equipment, with constraints due to access of existing roads and placement of existing plant equipment.
Soil Conditions/ Stability	Existing soil conditions are suitable for construction.
Construction Storm Water Control	Utilize best management practices for erosion control during construction. Additional storm water facilities are not necessary for operation.
Wetland Mitigation	Wetland Mitigation is not necessary for this project.
Landscaping	Landscaping not required for this project.
Rail Access	Delivery of equipment and reagents is expected to be by truck. Rail access is available; however, there is little spare capacity due to coal delivery.
Truck Access	Existing roads will be used for construction access. Temporary roads may also be needed for transportation of equipment or preassembled equipment modules. All roads will be paved with asphalt.
Laydown Areas	Sufficient space is available in close proximity to the work area
Structural	
Soil Bearing Capacity	Additional geotechnical information will be used to determine soil stability in specific areas of the project.
General Enclosures	Included
Platforms	Adequate platforms shall be provided to allow access to all components requiring routine maintenance.
Mechanical	
ID Fans	Two (2) new ID fans, single speed axial fans with variable blade pitch flow control. (Description of fans needs to be reviewed following completion or update to fan study)
Process Fans	Sparing philosophy includes 2x100% for most applications.
Process Pumps	Sparing philosophy includes 2x100% for most applications.
Compressed Air Supply	Existing plant air supply was stated to be inadequate to meet the air required by ReACT system. The N ₂ system is oversized to provide the ReACT system needs.
Service Water Supply	Existing plant service water supply will be used to provide service water required for ReACT system.
Cooling Water Supply	Existing plant cooling water supply will be used to provide cooling water required for ReACT system
Natural Gas Supply	Existing plant natural gas supply will be used to provide natural gas required for ReACT system.
Fire Protection & Detection	Fire protection shall be subject to review by local fire officials; currently includes tie-in to existing firewater system, existing controls and alarms systems. Fire detection will be included as required to initiate fire protection. Further, fire detection will be included in the electrical and control areas.
Emission Controls	
SO₂	Current SO ₂ limit is 1.2 lb/mmmbtu , (no averging period identified,

PUBLIC VERSION

	assumed to be 3 hr average). Current emissions 0.56 to 0.89 lb/mmbtu. Maximum 1.23 lb/mmbtu SO ₂ permitted in coal.
NO _x	Existing combustion controls: Low NO _x burners and Overfire Air. Current NO _x limit is 0.7 lb/mmbtu , (no averaging period identified, assumed to be 3 hr average). Current emissions 0.13 lb/mmbtu.
Mercury	Existing ACI system installed upstream of air heater. Expect to achieve at least 90% reduction on Unit 3 as a co-benefit of ReACT system without the use of the ACI system. Uncontrolled emissions are 4 to 8 lb/Tbtu.
Opacity	20% limit
Particulate	Existing fabric filter system installed. Current PM limit is 0.10 lb/mmbtu . Current emissions are 0.01 to 0.018 lb/mmbtu.
Electrical	
Auxiliary Power	Additional auxiliary power to ReACT system shall be supplied from existing available plant power. A new motor control center for the ReACT system is required. Based on the new load projections, more information may be required following completion of the electrical load study.
Control System	DCS tie-in with existing plant systems
Plant Communications	Included
Construction	
Performance Testing	Included for all components regardless of contracting approach.
Stack Testing	As required to meet regulations.
Commissioning and Start-up	Included
Operator Training	Included
Construction Utilities:	
Water Supply	Water supply for construction will be from existing water supply.
Construction Sanitary Facilities	Included
Construction Power	Existing plant will provide construction power requirements.
Equipment Delivery	Equipment will be received by truck.
Construction Schedule	It is assumed that the construction schedule will be adequate to allow the project to be completed with minimal overtime. Construction schedule will be estimated as a 5x10 schedule to incentivize labor.
Construction Facilities	Facilities (buildings) built to support construction shall be mobile and removed after construction.
Existing Facilities	No relocation of existing facilities is anticipated at this time. Demolition plans were discussed in Section 5.
Miscellaneous	
Permanent Plant Operating Spare Parts	Allowance included assuming some amount of spares.

APPENDIX E

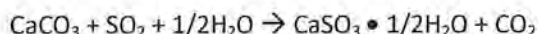
GENERAL SO₂ REDUCTION TECHNOLOGY DESCRIPTIONS

E.1 LIMESTONE FORCED OXIDATION

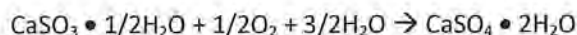
E.1.1 Process Description

LSFO is the primary technology used for WFGD systems with an excess of 80% of the market share. The process uses limestone (also known as calcium carbonate, CaCO₃) reagent and is capable of removing 97%+ of the SO₂ present in the inlet flue gas.

In the LSFO process using an open spray tower, hot flue gas exiting a new booster fan or existing ID fans enters a large open cylindrical absorber vessel with several layers of spray nozzles at the top. The nozzles spray dilute limestone slurry, typically 15%-20% by weight suspended solids, counter to the flue gas flow through the vessel, allowing for the maximum contact between the flue gas and limestone slurry droplets for improved SO₂ reduction efficiency. The SO₂ in the flue gas reacts with the calcium carbonate in the limestone particles to form calcium sulfite (CaSO₃) according to the following reactions:



The reacted slurry is collected in the absorber reaction tank (integral to the absorber vessel), where compressed air is introduced to force the completion of the reaction to calcium sulfate (CaSO₄, also known as gypsum) according to the following reactions:



This process alleviates problems such as gypsum scaling and dewatering difficulties. Some of the material is recycled back to the spray nozzles with fresh limestone slurry; the remainder is removed from the reaction tank and processed to form a dry gypsum by-product. The LSFO gypsum by-product is saleable as commercial-grade gypsum that can be used for wallboard manufacturing or other industrial applications. At some plants, the gypsum is sent directly to a landfill for final disposal. The scrubbed flue gas exits the top of the vessel through several layers of mist eliminators, which capture most of the fine aerosols. A process flow diagram for a typical LSFO system is shown in **Figure E.1**.

A considerable amount of water is necessary for the LSFO process, primarily for the reagent slurry and the mist eliminator wash water. The evaporation of water from reagent slurry cools the flue gas temperature from approximately 300°F at the inlet to approximately 130°F, which results in a saturated flue gas. Water is also required to replace water lost with the by-product solids, and blow down streams used to control dissolved solids and fines. Makeup water can be supplied from any source that is not saturated with respect to any of the dissolved solids and contains a relatively low concentration of suspended solids. For example, cooling water tower blow down can be suitable for makeup to the absorber. However, the mist eliminator wash stream, which serves as a large portion of the scrubber makeup, should be higher quality (e.g. plant service water) in order to maintain scale-free operation.

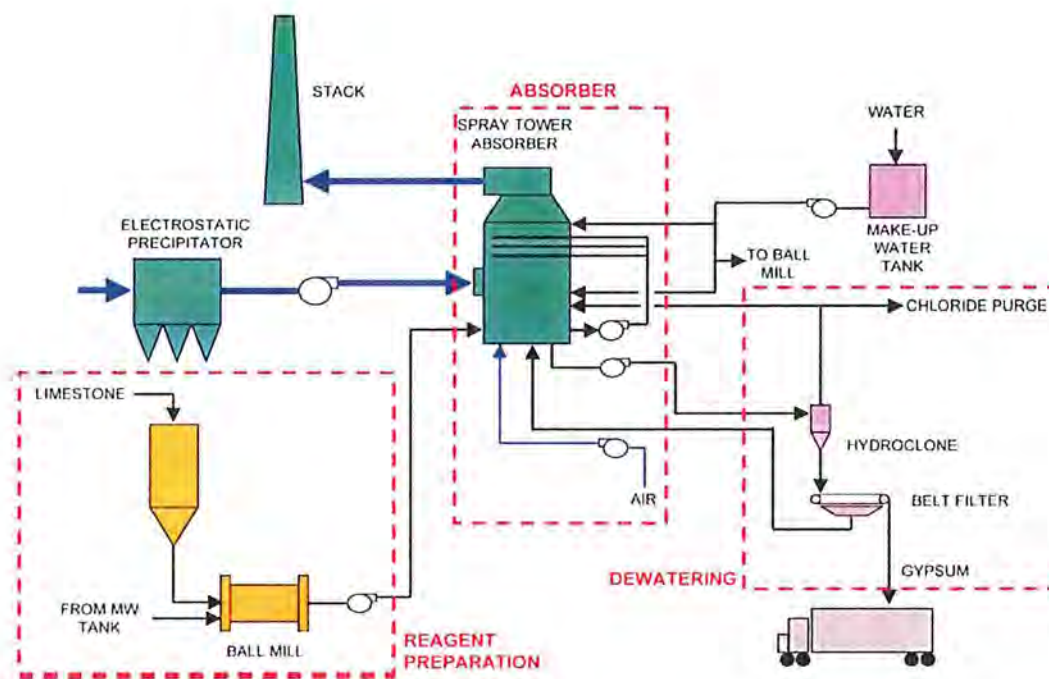


Figure E.1 Typical LSFO Process Flow Diagram

There is considerably more equipment required for wet scrubber installations, resulting in greater space requirements and increased power consumption. This equipment includes limestone unloading and preparation equipment, reagent mixing equipment, slurry recycle pumps, tanks, air compressors, vacuum filters, by-product processing equipment and wastewater treatment systems. In addition, because the flue gas is saturated with moisture, the absorber vessel and all downstream components must be fabricated with corrosion resistant materials. The scrubber vessel and ductwork are usually fabricated of a specialty stainless steels and/or chemically resistant linings, and the chimney liner is usually fiber-glass or some form of acid resistant brick.

E.1.2 Reagent Preparation

Limestone from the mine or local supplier is transferred by trucks or trains to a receiving area, and from there by conveyors to an on-site storage area (pile or silos). The reclaim system typically includes a vibrating feeder and conveyor system to transfer crushed limestone to day-bins. Limestone day bins and feeders supply limestone to either horizontal or vertical-type ball mills. The ball mills grind the limestone to 95 percent less than 325 mesh and use a wet recycle classification loop to ensure proper size distribution to the process. This particle size produces a large surface area for gas contact without excessive power consumption by the ball mill. The 30-35 percent solids slurry from the ball mill system is stored in limestone slurry tanks prior to transfer to the absorbers.

E.1.3 By-product Handling

The gypsum slurry removed from the absorber reaction tank is saturated with large dense gypsum crystals. The gypsum is separated from the water in a two-step process. Hydroclones are used first to dewater the slurry to about 50 percent solids while returning un-reacted limestone to the scrubber reaction tank in the overflow stream. The underflow is directed to a secondary dewatering facility, which uses either rotary drum or vacuum belt filters. The cake coming off of the horizontal belt filter is typically a minimum 90 percent gypsum solids and less than 10 percent water. The rotary drum filter will dewater the slurry to approximately 80% to 85% gypsum solids. The recovered liquid is returned to the scrubber reaction tank. If the gypsum is to be sold for industrial use (e.g. wallboard or cement manufacturing, agricultural use), a washing sequence is included in the vacuum filter design to reduce chloride content and to eliminate contamination. The cake wash water is usually heated to promote drying to less than 10% moisture.

The gypsum from the vacuum belt filter is transferred by belt conveyor to a storage building until sold or transported off site to a landfill.

E.1.4 Wastewater Treatment

Blow down of a portion of the process water returned from the gypsum dewatering/washing process is necessary to control the concentrations of dissolved and suspended solids in the scrubber liquor since these dissolved solids concentrate due to the continuous recycle of scrubber slurry and evaporation of water into the flue gas. The blow downstream is also used to control chloride levels in the absorber reaction tank and recycle system. The blow down stream may also be used to purge fines, which tend to bind to filter cloths, leading to difficulties in dewatering.

The quality of wastewater purge stream from the FGD process depends upon the sources of makeup water, the coal composition, and the by-product specifications. Contaminants that may require removal could include trace heavy metals and chlorides. The standard FGD wastewater treatment (WWT) system consists of a multi-stage physical/chemical treatment system that includes precipitation, flocculation, and dewatering equipment to address mercury, iron, cadmium, and other contaminants. Generally, chlorides are not removed in a physical/chemical treatment system and are carried out with the WWT system discharge. The solids generated by these treatment systems have to be disposed of properly. The liquid stream can be used for coal pile wetting, ash sluicing, and/or combined with the plant cooling water discharge.

An alternative to a physical/chemical treatment system is zero liquid discharge (ZLD). ZLD can be used to remove dissolved solids and heavy metals, such as mercury, in addition to chlorides. A fully integrated ZLD system incorporates lime softening followed by a mechanical vapor compression brine concentrator and a steam driven forced circulation crystallizer and filter press system. The only ZLD installation in the United States was at AES Cayuga Station (formerly NYSEG's Miliken Station) as part of the Department of Energy's Clean Coal Demonstration Project. The evaporator system experienced numerous problems and did not work satisfactorily during the demonstration. Operational problems included plugging of the evaporator tubes and corrosion of various parts of the system. The system was subsequently abandoned. Modifications to the process used at the demonstration site have been suggested, but they present challenges of their own, such as solids handling. Aquatech, a supplier of ZLD systems, has five installations at FGD sites in progress in Italy at various stages of construction and

operation; the furthest along having several months of operating time. Until the technology has matured and some of the challenges of treating FGD wastewater are addressed, achieving zero-liquid discharge would be difficult. In addition, the systems are very expensive to install because of the materials of construction required to prevent corrosion. There is very little operating and maintenance data available, but it is expected that O&M costs would be very high until the technology matures and some of the challenges of treating FGD wastewater are addressed.

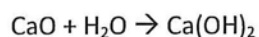
E.2 SPRAY DRYER ABSORBER SYSTEM

E2.1 Process Description

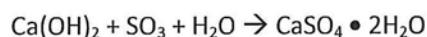
A SDA system is a semi-dry FGD system that can consistently achieve +90% SO₂ removal. The SDA system is considered a semi-dry process because a liquid slurry reagent is used; however, the by-product is a dry mixture of fly ash and reaction products. In the SDA process, the hot flue gas exiting the induced draft fan(s) enters the top of the spray dryer vessel. Within the vessel, atomized slurry of lime and recycled solids contact the flue gas stream. The sulfur oxides (SO₂ and SO₃) in the flue gas react with the lime and fly ash alkali to form a mix of calcium salts, un-reacted reagent, and fly ash. The water entering with the slurry vaporizes, lowering the flue gas temperature and raising the moisture content of the scrubbed gas. The spray dryer outlet temperature is typically controlled within 30-35°F above the gas saturation temperature. A closer approach to the saturation temperature allows the SDA system to achieve higher removal efficiency, but risks condensation of water and build-up of wet solids on internal surfaces increasing the potential for corrosion and plugging of the gas path and filter bags.

The scrubbed gas and dry reaction products leave from the side or the bottom of the SDA vessel. A particulate control device, typically fabric filters is installed/operated downstream of the SDA vessel to remove the dry solid reaction products, un-reacted reagent, and fly ash before the scrubbed gas is released to the atmosphere. The filter bags collect a layer of solids on their surfaces between cleanings, and the movement of the flue gas through this layer enhances the gas-solid contact, resulting in additional SO₂ reaction with the residual lime in the collected filter cake solids. As much as 25% of the total SO₂ removal can occur in the fabric filters. A portion of the collected reaction products and fly ash solids is recycled to the slurry feed system. The remaining solids are transported to a landfill for disposal.

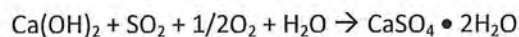
The chemical reactions defining the SO₂ removal process as well as a process flow diagram for the spray dryer absorber system are given below. Raw lime (CaO) is slaked with an excess of water to form a calcium hydroxide (Ca(OH)₂) slurry:



The sulfur oxides (SO₂ and SO₃) in the flue gas are absorbed into the slurry and react to form calcium sulfite (CaSO₃) and calcium sulfate (CaSO₄) salt products:



A fraction of the sulfite product may also be oxidized to the sulfate form by reaction with oxygen in the flue gas:



Any HCl in the flue gas, present because of the chloride content of the coal, is also absorbed into the slurry and reacts with the slaked lime to form a dry salt by-product:

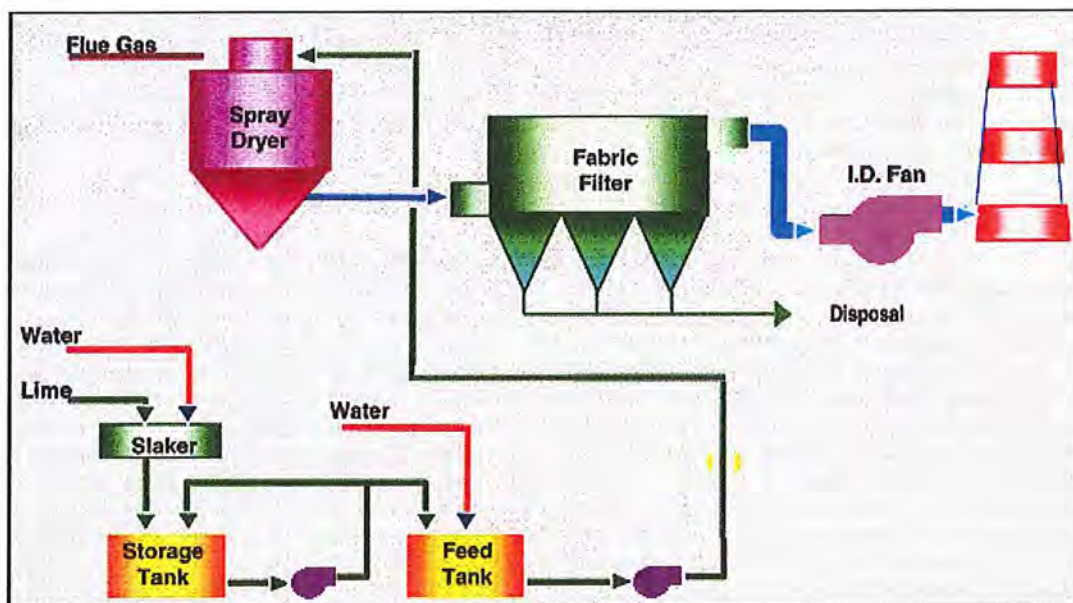
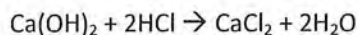


Figure E.2 Typical SDA Process Flow Diagram

As the reactions above indicate, the SDA process is highly effective at controlling SO_3 , which can condense with water vapor to form sulfuric acid mist. Over 90% of the sulfur trioxide that is formed during combustion is absorbed in the SDA vessel and fabric filters. This eliminates the potential for plume opacity due to acid mist or acid corrosion in the downstream ductwork and particulate collection system.

The SDA system consists of less solids handling equipment than wet scrubber systems, reducing the auxiliary power consumption. This equipment includes lime unloading and storage equipment, reagent slaking equipment, slurry pumps, tanks, rotary atomizer(s), and by-product handling equipment. Additional equipment may be required if a recycle system is incorporated with the SDA to increase reagent utilization. Because the flue gas is maintained above the saturation temperature throughout the process, the absorber vessel and all downstream components can be fabricated of carbon steel.

E.2.2 Reagent Preparation

The feed reagent used in a spray dryer absorber is typically lime in pebble form. The lime is transferred from bulk storage to a slaker. Fresh water is introduced to the slaker to hydrate the pebble lime and produce slurry that typically contains 19 wt% solids. A ball mill slaker pulverizes the inert material and mixes the inerts with the reagent slurry. If a detention or paste slaker is used, the inert grits are removed at the slaker for separate disposal. The slaked lime, Ca(OH)_2 , flows to an agitated lime slurry feed tank. This slurry is then pumped to the spray dryer rotary

atomizer (or dual fluid atomizers offered by some SDA vendors) where it is injected into the flue gas along with additional water to control the outlet temperature within 30-35°F above the gas saturation temperature.

E.2.3 By-product Handling

The spray dryer system produces a dry solid product consisting of calcium sulfite/sulfate, unused hydrated lime, and fly ash. These dry solid products can be handled by conventional dry fly ash handling systems. A portion of the collected reaction product and fly ash solids may be recycled to the slurry feed system to increase reagent utilization and reduce operating cost; the remaining solids are sent via the dry solids conveying systems to a storage silo. From the silo they are trucked to a landfill for disposal. Because the reaction products are dry, there are no wastewater streams. At this time, there is little or no market for SDA waste solids.

E.3 CIRCULATING DRY SCRUBBER

E.3.1 Process Description

The Circulating Dry Scrubber (CDS) process is a dry scrubbing technology that can consistently achieve ~94-95% SO₂ removal. The process is totally dry, meaning it not only produces a dry, free flowing disposal product, but also introduces the lime reagent as a dry, free flowing powder. Water is injected into the CDS scrubbing vessel separately from the dry lime feed. In the CDS process, flue gas enters the bottom of the fluidized bed reactor(s). As the flue gas enters the venturi-shaped entrance to each reactor, it is mixed with hydrated lime reagent and recycled fly ash and reaction product solids. Water is injected into the reactor to cool and humidify the flue gas and assist in SO₂ removal. The flue gas outlet temperature is controlled to around 35°F above the saturation temperature. The CDS reactor has a tall cylindrical configuration to allow adequate time for the reaction of the sulfur oxides (SO₂ and SO₃) in the flue gas with the reagent. The by-product is a mixture of calcium salts, un-reacted reagent, and fly ash.

The spent solids and fly ash are carried out of the top of the reactor and captured downstream by fabric filters or the electro-static precipitator (ESP). A portion of these combined solids are recycled to the fluidized bed absorber via air slides. The remaining material is transported to a solids silo. The fly ash and reaction products are drawn from the silo and conditioned in a pug mill(s) for disposal to landfill – there is little or no market for this mixed solid waste. A process flow diagram for CDS is shown in Figure E3 below.

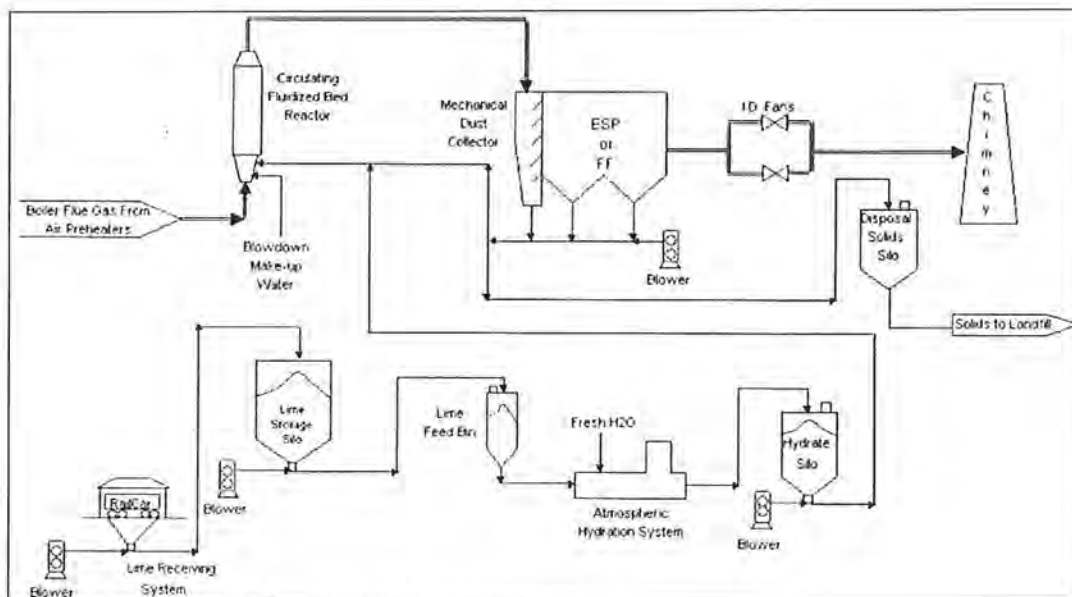
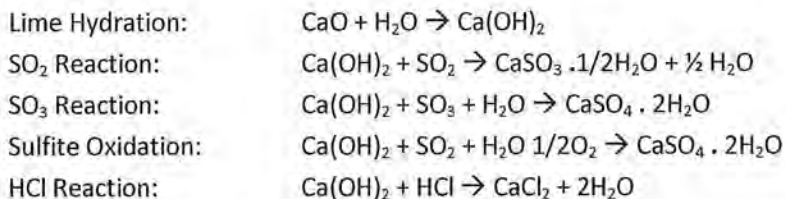


Figure E.3 Typical CDS Process Flow Diagram

The CDS process chemical reactions are similar to that of the SDA, as shown below:



E.3.2 Reagent Preparation

Pebble lime is transported pneumatically from the lime storage silos to the lime day bin, which feeds the dry lime hydration plant. From the day bin, pebble lime is fed into a lime hydrating fluidized bed reactor. The pebble lime is hydrated by the injection of fresh water in the hydrating reactor in an amount proportional to the feed rate of the pebble lime. Hydrating water consumption is approximately 150% of the stoichiometric requirement. The highly reactive hydrated lime product, which is still considered to be a dry powder, is pneumatically transported to hydrated lime surge bins. The hydrated lime reagent is drawn from each hydrated lime surge bin by variable speed rotary feeders that transfer the hydrated lime to an air slide that conveys and feeds the hydrated lime into the associated CDS scrubber tower.

E.3.3 By-product Handling

The flue gas exits the CDS reactors and is drawn through fabric filters. Hydrated lime and SO₂ reaction products are separated from the flue gas and collected with the fly ash in the fabric filter hoppers. The fly ash and reaction solids are discharged from the hoppers and split into two streams. The first stream is recycled via an air slide and fed back into the lower section of the associated CDS reactor. The second stream is discharged through an airlock hopper and transported by a pressurized pneumatic conveying system to a fly ash/reaction products storage

silo. The fly ash and reaction products are gravity discharged from the silo into a pug mill. The pug mill conditions and discharges the ash and reaction products into ash dump trucks for transportation to a landfill.

E.4 DRY SORBENT INJECTION SYSTEM (DSI)

E.4.1 Process Description

The Dry Sorbent Injection (DSI) technology has been available for commercial application to utility SO₂ control since the 1980s based on initial testing in the 1970s. Highly reactive sodium compounds, including Trona (naturally occurring sodium sesquicarbonate – Na₂CO₃ • NaHCO₃ • 2H₂O), sodium bicarbonate, and Nahcolite (a naturally occurring sodium bicarbonate) have all been used for FGD applications in multiple demonstration programs at power generation facilities. The delivered cost of these reagents and their relatively high reagent feed rate required to achieve moderate levels of SO₂ reduction, along with the solubility of the waste solids produced, have limited their application to only a few plants in the U.S. However, in the current regulatory environment, and given the age of many of the smaller units that are now faced with SO₂ emissions regulations, the relatively low capital investment required for DSI system installations has increased the level of interest in these systems.

The technology is simple – a storage silo is required to receive the reagent at the site, a pneumatic conveying system moves the solids from the silo to the mill and then to the injection grid located upstream of the air heater. The injection rates required above 50-65% SO₂ reduction is likely to require a fabric filter to both handle the larger solids loading in the flue gas, as well as to provide additional contact time for increased SO₂ removal. The dry solid waste mixture is then removed from the particulate collector hoppers and stored temporarily in silos before transfer to the final disposal site. The sodium salts in this mixed waste (unreacted sodium reagent, fly ash and reaction products) will be highly soluble in water. They may require an existing landfill area to modify its operating procedures to potentially provide encapsulation of the waste material and/or to install a new liner and leachate collection system for the area handling the DSI waste (then also confirm the ability to handle the leachate that can have a higher pH and larger concentrations of sodium compounds).

Data in the literature indicates that sodium concentrations in the DSI waste can increase by more than a factor of 10-20 compared to the initial concentration in the fly ash. The basic process chemistry is outlined by the following reactions when using Trona:

Decomposition:



Absorption Reaction:



Refined sodium carbonate was found in earlier testing to not be an acceptable reagent for FGD applications, possibly because it does not undergo the decomposition reaction that increases porosity and available surface area for reaction with the SO₂.

The DSI system would utilize Trona (Sodium Sesquicarbonate) or Sodium Bicarbonate as the reagent injected upstream of the bag house to collect the dry reaction product. The fabric filter

would also serve the activated carbon injection (ACI) system for mercury control and as the final control for non-condensable particulate matter.

E.4.2 Summary of Full-Scale Experience

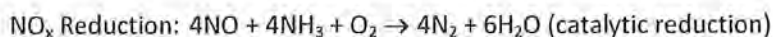
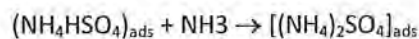
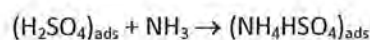
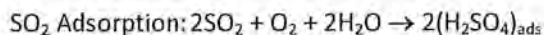
Currently, there is some interest in DSI by several utilities but no commercial commitments have been made.

Utility	Plant / Units	Project	Current Status
Connectiv	Edgemoor	SO ₂ Demonstration	Unit converted to gas. Reported 67% SO ₂ reduction when system was in operation.
Dynegy	Danskammer	SO ₂ Demonstration	Permanent system in place for 1+yr, but not continuously operated.
NRG Energy	Huntley	SO ₂ Control (Also ACI for Mercury Control)	Permitted 55% SO ₂ reduction w/fabric filter. 90% mercury removal. DSI shut down due to switch to PRB.
NRG Energy	Dunkirk	SO ₂ Control (Also ACI for Mercury Control)	Permitted 55% SO ₂ reduction w/fabric filter. 90% mercury removal. DSI shut down due to switch to PRB.
Xcel Energy	Cherokee 1,3,4	SO ₂ Control	Installed 1990. Unit 1 scheduled to be shut down in 2011. Unit 3 was shut down in 2001. Unit 4 replaced DSI with other FGD.
Xcel Energy	Arapahoe 3	SO ₂ Control	20% SO ₂ reduction on 40 MW PRB Unit since 2003. Scheduled to be converted to gas by 2013.

E.5 MULTI-POLLUTANT FLUE GAS DESULFURIZATION (REACT)

E.5.1 Process Description

The ReACT process consists of three stages: adsorption, regeneration, and by-product recovery. Flue gas from an upstream particulate collector enters the adsorber and passes through a moving bed of AC with ammonia injection to simultaneously remove SO₂, NO_x, and Mercury from the flue gas. Spent AC from the adsorption process is regenerated and recycled back to the adsorber, while SO₂ rich gas (SRG) is sent to a by-product recovery unit and processed into saleable sulfuric acid. ReACT also removes residual particulate from the flue gas. The following equations describe the ReACT process:



In the adsorption step of the process, ammonia is injected into the flue gas, which then passes through an adsorption tower containing a moving bed of AC pellets. The SO_2 in the flue gas reacts with oxygen, water, and ammonia to form various compounds described in the equations above, which adsorb onto the surface of the AC. The NO_x in the flue gas is catalytically reduced to nitrogen and water by reaction with ammonia in the AC bed and reducing compounds on the surface of the AC. The SO_2 saturated AC is conveyed to a regenerator vessel, where indirect heating to $750^\circ\text{--}930^\circ\text{F}$ thermally regenerates the AC and releases the SO_2 . The regenerated AC is then recycled back to the adsorber. The SRG is converted to a saleable by-product such as sulfuric acid.

Mercury in the flue gas is removed by adsorption onto the surface of the activated AC in the presence of SO_2 , regardless of speciation and chlorine content in the flue gas. The adsorbed mercury desorbs from the AC during the regeneration process, but is adsorbed again in the upper section of the regenerator where the temperature is cooler. The mercury, therefore, accumulates on the activated AC in the regenerator. As a result, a portion of the activated AC needs to be extracted from the process every few years depending on the mercury concentration in the coal.

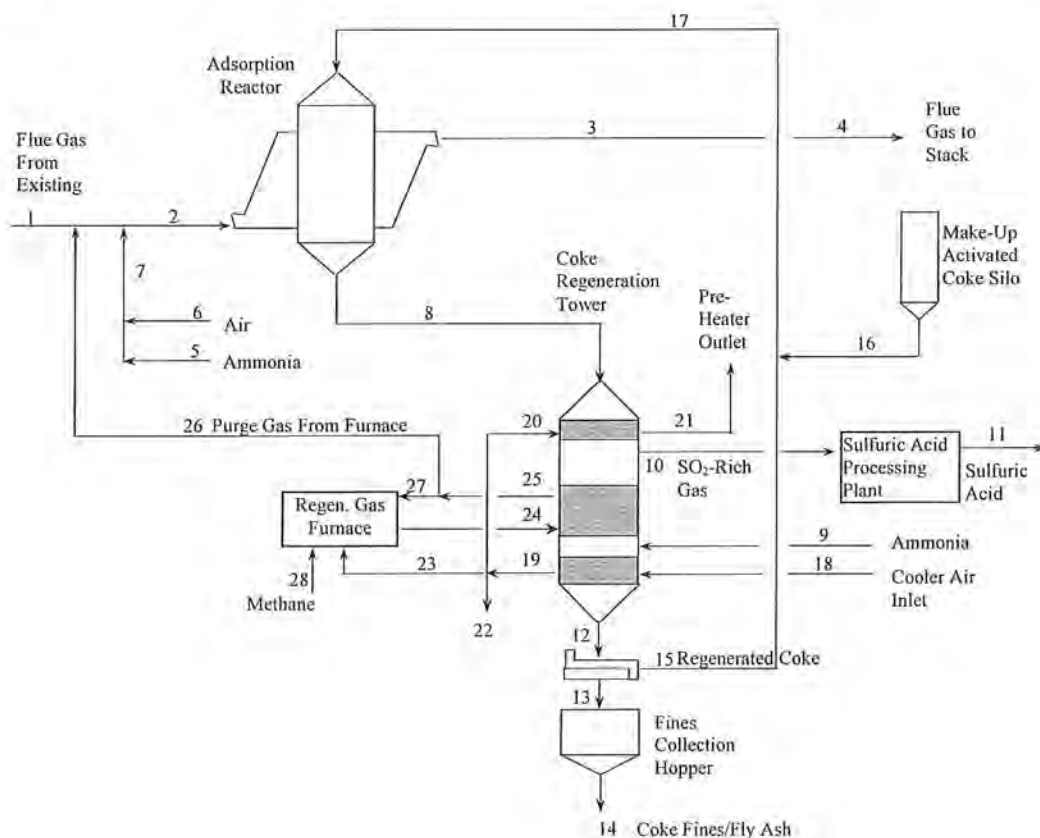


Figure E.4 ReACT Process Flow Diagram

E.5.2 Reagent Preparation

The AC used in the ReACT process is approximately a ½"-diameter pellet or almond-type shape and has a high mechanical strength against abrasion and crushing. The AC is produced and supplied in its final form from off-site sources.

E.5.3 By-product Handling

The AC is transferred between the adsorber and regenerator using a series of conveyors and bucket elevators. The regenerated AC passes through a vibrating screen to remove any degraded fine material. Fresh AC is added to replace any fines removed during the screening process and AC lost during the desorption of the SO₂ compounds. The waste AC stream can be returned to a boiler for burning.

Since the fabric filters are upstream of the ReACT process, the fly ash will remain a saleable by-product.

SRG from the regenerator is directed to the acid plant where salable sulfuric acid is produced and supplied as a by-product to meet market requirements. Included in the design is a small natural gas or electric heater used during start up and low load operation. The heater exhaust and remaining gas flow from the acid plant is directed back to the adsorber inlet where it combines with the boiler flue gas to be cleaned and eventually exits the main stack.

The salable sulfuric acid is stored in an acid storage tank designed for an approximate storage of 10 – 15 days.

APPENDIX F

GENERAL MERCURY REMOVAL TECHNOLOGY DESCRIPTIONS

F.1 MERCURY SPECIATION

Mercury contained in coal vaporizes during the combustion process into two forms of mercury: elemental mercury (Mercury⁰) and oxidized mercury (Mercury²⁺). For Powder River Basin (PRB) coals, such as those fired at Weston Station, the elemental form of mercury dominates, accounting for 70% to 90% of the total mercury in the flue gas. The prevailing theory as to the dominance of elemental mercury is the fact that PRB coals contain low amounts of halogen elements, both chlorine and bromine, which aid in the oxidation of the mercury. The speciation of mercury in the flue gas is important because the oxidized form of mercury is water soluble and easier to capture and remove than the elemental form, especially in wet FGD systems.

F.2 ACTIVATED CARBON INJECTION

The activated carbon injection process is the only mercury control technology that is considered commercially available with commercial projects operated for extended periods at coal-fired utility boilers. Injection of carbon upstream of an existing ESP or a fabric filter has been tested and installed at full-scale on a number of units.

Carbon injection (plain and treated with halogens) upstream of fabric filters has shown mercury removal capabilities in excess of 90% during long term tests. The activated carbon will collect on the filter bags, and then drop into the collection hoppers located under the fabric filters. This arrangement may prevent the beneficial reuse of fly ash due to the increased carbon content. The injection grid for activated carbon would be installed in the ductwork upstream of the fabric filters.

When AC sorbent injection is combined with a Compact Hybrid Particulate Collector (COHPAC), essentially a small pulse jet fabric filter, the technology has been given the name TOXECON, a system configuration currently patented by the Electric Power Research Institute (EPRI). Carbon injection upstream of existing fabric filters or one installed as part of an SDA system is the same basic concept as TOXECON. Carbon injection upstream of the SDA vessel may result in mercury removal efficiencies greater than that of TOXECON due to the increased contact time between the carbon and flue gas.

F.2.1 TOXECON I

The TOXECON I system, ACI upstream of a COHPAC fabric filters, has seen the most field-testing and forms the basis for the commercial offering by one vendor. **Figure F.1** provides a flow diagram for the TOXECON I system. The major components of the TOXECON I design include a pneumatic transfer system for connection to trucks delivering the activated carbon. The pneumatic piping transfers the activated carbon to the storage silo(s) that are equipped with a vent filter and weigh feeders. The feeders transfer the activated carbon to the pneumatic feed lines that move the AC to the injection location.

An injection grid is fed by a stream splitter that transfers the activated carbon to multiple injection lances feeding the injection grid installed in the ductwork. The solids are then collected in a

downstream COHPAC fabric filters. This fabric filter will add 8-10" w.g. pressure drop to the flue gas at a typical filtering velocity of 4-6 feet per minute. The filter media collects the activated carbon solids from the flue gas and provides additional contact time for removal of the mercury. The solids are periodically removed from the fabric filters and pneumatically transferred to a separate silo for ultimate loading onto trucks sent to a landfill. In this case, only trace quantities of fly ash would be expected in the carbon sent to a landfill. Testing to date indicates that mercury adsorbed in activated carbon will not leach out into the groundwater. However, the EPA has not made any formal rulings on the hazards associated with carbon bound mercury.

This system has shown mercury removal capabilities in excess of 90% when utilizing activated carbon (plain and treated). However, long-term results show an average of 85% reduction in mercury levels from the inlet flue gas concentration.

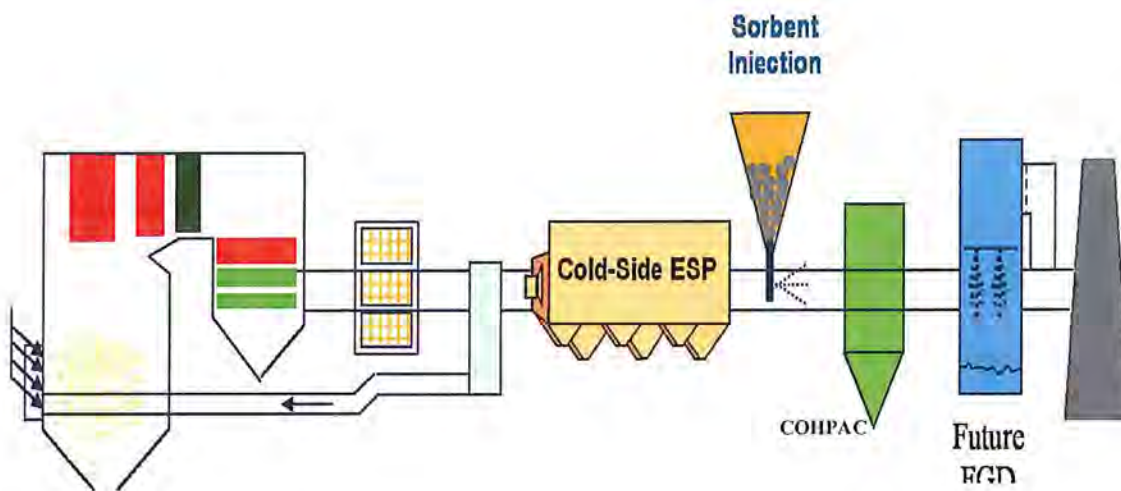


Figure F.1 TOXECON I Arrangement

F.3 SORBENTS

Sorbents used in a majority of mercury control demonstration projects include plain (powdered) and treated (brominated/halogenated) activated carbons. Both sorbents have test data showing 50-90% mercury removal with injection rates ranging from 2-10 lb/MMACF. The injection of AC will also contaminate the fly ash unless the ash is removed upstream of the injection grid; this can make the fly ash unmarketable for some applications, most notably as a concrete additive.

F.3.1 Plain Activated Carbon

Plain (untreated) activated carbon is commercially available from multiple vendors both domestically and internationally. These activated carbons are capable of achieving 90% mercury removal with fabric filters, but at injection rates sometimes approaching 10 lb/MMACF. Performance varies between the carbon suppliers. This type of activated carbon is mass-produced for commercial applications other than mercury control for coal fired power plants.

F.3.2 Halogenated Activated Carbon

Treated activated carbon is produced by adding bromine, iodine or fluorine to the carbon to increase its ability to capture mercury. Field testing with halogenated activated carbons indicates that they can achieve 90+% mercury removal at injection rates of 3 lb/MMACF or less. The trade off is that treated activated carbons cost more than untreated carbon, but with increased production capacity projected as more carbon injection systems go on-line, the price of treated carbon is expected to drop.

Sorbent names include BPAC from Sorbent Technologies (now owned by Albemarle) and Darco Mercury-LH from Norit Americas; both are treated with bromine. Sorbent Technologies is also developing and promoting the use of an activated carbon sorbent that will have little to no effect on concrete production.

F.4 COAL PRE-TREATMENT/WET FGD CO-BENEFIT

This concept involves oxidizing elemental mercury with small amounts of a halogen added to the boiler and then capturing the oxidized mercury by conventional SO₂ control devices. The presence of chlorine and/or bromine promotes the oxidation of mercury, and oxidized mercury is readily removed across a WFGD system. Calcium chloride and calcium bromide injection into the furnace or added to the coal prior to combustion have been tested on a limited scale on plants burning PRB, as well as North Dakota and Texas lignites.

The test results to date have increased the mercury removal across the WFGD systems from a baseline of 45-55% to 73-81% with halogen treatment of the fuel. Testing to date has been for short durations and long-term balance-of-plant impacts have not been determined. Further testing is planned.

The injection of bromine and bromide compounds into the boiler, flue gases, or onto the coal prior to combustion for enhancing mercury oxidation and removal.

When coupled with ACI or high natural unburned carbon levels, this technology has achieved short-term mercury removal rates of up to 94% combined across the particulate control device and FGD system.

Other developers are also attempting to pursue systems, including the ISCA Company, which claims to hold patents on the injection of chlorine or chlorine compounds into flue gas to oxidize elemental mercury upstream of an FGD system. In addition, Chem-Mod LLC announced that it has developed a series of coal additives that reduce mercury emissions through oxidation and subsequent collection in other control equipment.

F.5 CHEMICAL ADDITIVES TO CONTROL MERCURY RE-EMISSION FROM FGD SLURRY

Testing is being conducted to evaluate the use of additives in wet lime or limestone FGD systems to prevent oxidized mercury from being reduced and subsequently re-emitted from the FGD absorber as elemental mercury. Reducing or eliminating the amount of mercury that is re-emitted from the FGD system will increase the overall collection efficiency of the system. Testing is being conducted at three sites that burn: (1) Texas lignite, (2) a low-sulfur bituminous coal, and (3) a high-sulfur bituminous coal. There are no test results to report at this time.

PUBLIC VERSION

Both Babcock & Wilcox and URS Corporation have completed field-testing of these chemical additives to reduce the vapor pressure of mercury over the scrubber slurry. Mitsubishi Heavy Industries is promoting its development of an oxidation/sulfite control system that will control the potential for mercury re-emission by ensuring that sulfite concentrations are maintained in the proper range.