



**Assessment of Technology Options
Available to Achieve Reductions
of Hazardous Air Pollutants**

Prepared by:

URS

April 5, 2011

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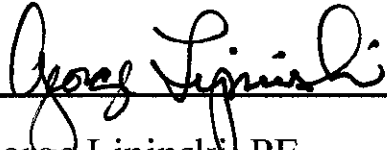


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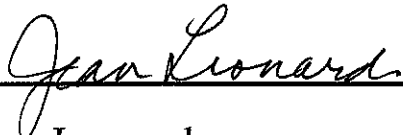
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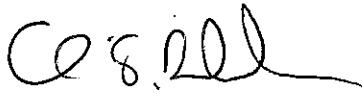
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ACI	Activated Carbon Injection
AH	Air Heater
AQC	Air Quality Control
CAA	Clean Air Act
CFB	Circulating Fluidized Bed
CO	Carbon monoxide
COHPAC	Compact Hybrid Particulate Collector
DSI	Dry Sorbent Injection
EMPC	Estimated Maximum Possible Concentration
ESP	Electrostatic Precipitator
FF	Fabric Filter
FGD	Flue Gas Desulfurization
FGDd	Dry Flue Gas Desulfurization (Spray dryer or circulating fluidized bed scrubber)
FGDw	Wet Flue Gas Desulfurization
HAP	Hazardous Air Pollutant
HCl	Hydrochloric Acid
HCN	Hydrogen cyanide
Hg	Mercury
ICI	Industrial, Commercial, and Institutional
ICR	Information Collection Request
LOI	Loss on Ignition
MACT	Maximum Achievable Control Technology
NESHAP	National Emission Standards for Hazardous Air Pollutants
NSR	Normalized Stoichiometric Ratio
PM	Particulate Matter
PRB	Powder River Basin Coal
RICE	Reciprocating Internal Combustion Engine
SBS	Sodium Bisulfate
SCR	Selective Catalytic Reduction
SOFA	Separated Over-Fire Air
SO ₃	Sulfur Trioxide
TEF	Toxic Equivalency Factor
TEQ	Toxicity Equivalent
UPL	Upper Prediction Limit
ZWD	Zero Water Discharge



Executive Summary

This report¹ describes the results of an assessment conducted by URS Corporation (URS) to evaluate the availability of pollution control technologies to meet the requirements of the proposed National Emission Standards for Hazardous Air Pollutants (NESHAP) for Utility Electric Generating Units (“EGUs”) (the “Toxics Rule”). This assessment was designed to answer the ultimate question of whether control technologies are available that will equip EGUs to meet the emission limitations the Environmental Protection Agency (EPA) has proposed, regardless of current configuration. URS identified proven, commercially available control technologies that will enable EGUs to achieve compliance with the Toxics Rule, given adequate investment by the owners. In the event that an EGU requires the installation or upgrade of control equipment, the technologies available typically require less than three years to install after detailed design and permitting is complete.

To begin, URS identified a number of typical control equipment configurations present at existing EGUs. An assessment was performed to evaluate additional control technologies appropriate for those configurations that would enable EGUs to comply with the Toxics Rule emission limitations on hazardous air pollutants (“HAP”). URS consulted its own experience and database of pollution control technologies and reviewed published literature, conference proceedings, expert analysis and procurement information regarding the availability, cost and efficacy of numerous available control technologies. URS applied this information and its own experience to evaluate the menu of control options that would be available to EGUs of different configurations, and to rank those options. This analysis took into account the performance, maturity and number of existing commercial installations of the control technologies. While special cases may exist, this analysis demonstrates that the Toxics Rule emission limitations are generally achievable through the application of proven, commercially available technologies, regardless of the starting configuration of the facility.

Assuming EPA signs the final Toxics Rule as scheduled on November 16, 2011, the rule will not be effective until early 2012, or 60 days after it is published in the Federal Register. EGUs will not be required to comply with the Toxics Rule until three years after the effective date, or early 2015 – nearly four years after proposal. To the extent that existing facilities require additional control technology to comply with the Toxics Rule, the technology is known, available and the industry has demonstrated its ability to install and to operate these controls.

¹ This report was prepared by URS Corporation for Exelon Corporation.



The controls that will be most commonly needed, such as activated carbon injection (for mercury control) or dry sorbent injection (for SO₃ control on bituminous fired plants and acid gas control at some western sub-bituminous fired EGUs) typically require less than eighteen months to install once permitting is completed. Barring unreasonable permitting or supply chain delays, EGU owners who act promptly will be able to complete such low capital upgrades by the compliance date. Facilities requiring high capital upgrades such as the addition of wet FGDs will face longer installation times. Owners of EGUs requiring such additions will need to select technologies and contractors and to file permit applications promptly to meet the 2015 compliance deadline. For those facilities facing unique challenges in completing necessary upgrades by 2015, EPA has indicated that it will provide extensions of up to one year.

1.0 Introduction

In performing this assessment, URS considered the emissions limitations proposed by EPA in the Toxics Rule, reviewed relevant commercially available control technologies and evaluated seven hypothetical configurations of existing control equipment to determine whether such facilities could be brought into compliance with the proposed Toxics Rule emission limitations. It was concluded that: 1) in many instances, no additional controls would be required; 2) where additional controls would be necessary, the most common top-ranked control technologies can typically be installed in less than 24 months; and 3) in all other instances considered in this assessment, the top-ranked control technology can typically be installed in less than 36 months after detailed design and permitting is complete.

2.0 Technology Survey

2.1 EPA's Proposed Emission Limitations

In the Toxics Rule, EPA proposes emissions limitations for five different sub-categories of EGUs. Coal-fired EGUs are divided into lignite, non-lignite and integrated gasification/combined cycle ("IGCC") sub-categories. Oil-fired EGUs are divided into solid fuel (petroleum coke) and liquid fuel sub-categories. EPA has proposed emission limitations for mercury, hydrogen chloride ("HCl") and total particulate matter ("PM") for all coal-fired EGU sub-categories and the solid fuel oil sub-category, with HCl being a surrogate for all acid gases and PM being a surrogate for non-mercury HAP metals. For liquid oil-fired EGUs, EPA has proposed limits on total HAP metals (including mercury), HCl and hydrogen fluoride ("HF"). EPA has proposed to regulate dioxins/furans and other organic HAPs for all sub-categories through work practice standards rather than numerical emission limitations. EPA has also proposed a number of alternative compliance methods. For example, coal-fired EGUs may use sulfur dioxide ("SO₂") as a surrogate for acid gases in certain circumstances, and may test for total non-mercury HAP metals or ten individual HAP metals in lieu of complying with the PM limitation.

2.2 URS' Technology Survey

URS conducted a review of commercially-available air quality control ("AQC") technologies that may be employed by coal- and oil-fired EGUs in order to meet emission limitations proposed by EPA in the Toxics Rule. This technology survey presents control technologies for Mercury, HCl, and PM, the default emission limitations in the Toxics Rule for



coal-fired EGUs and solid fuel oil-fired EGUs.² Although EPA proposed different emission limitations for liquid fuel oil-fired EGUs, the technologies available for controlling PM and HCl at other EGUs would control total HAP metals and HF (as well as HCl) at liquid fuel oil-fired EGUs.

To conduct the control technology assessment, URS utilized internal information on air quality control technologies, as well as information from published literature and conference proceedings, discussions with technology experts, and procurement information associated with some technologies. For each pollutant category, air quality control technologies were evaluated for their ability to achieve sufficient performance levels. Although costs were not a primary factor in the selection of appropriate technologies, they were considered when comparing different technologies with similar expected performance levels. The multi-pollutant nature of various technologies was also considered, as some processes would be expected to effectively remove pollutants from a number of potential HAP categories, allowing a holistic approach to achieving compliance with the Toxics Rule. Through this analysis, a ranking of available control technologies was developed that takes into account cost, maturity and the ability to treat multiple HAPs. This assessment did not consider possible technologies for controlling dioxin/ furan emissions or organic HAPs. Under the proposed Toxics Rule, these HAPs are to be controlled through work practice standards.

The analysis demonstrates that there is a range of control technologies available to EGUs requiring additional levels of control for mercury, HCl or PM. These technologies are proven and mature, and in fact are already installed at many EGUs. Many of the available technologies involve relatively low capital retrofits that typically require less than eighteen months to install. Some technologies, such as wet or dry scrubbers, have longer installation times and EGU owners requiring such additions will need to move more rapidly to meet the 2015 compliance deadline.

2.3 Assumptions Regarding Existing Sources

URS assessed AQC technologies for expected performance, cost, and schedule to construct at power plants of several different configurations. It should be noted that for any particular facility, technology assessments must be conducted on a site-specific basis, taking into account the plant's existing equipment, current operating scenarios, physical layout and balance of plant considerations, as well as economic and long-term planning considerations. For the purposes of this study, several common configurations of AQC technology already in place at

² URS did not specifically address the applicability of any particular technology to IGCC units.



existing fossil-fuel fired facilities were identified to address expected need for additional controls to reduce the emissions of toxic air pollutants. These hypothetical configurations consist of one or a combination of control technologies for PM, SO₂ or oxides of nitrogen (“NO_x”).

The most common PM control technologies are fabric filters (“FFs”) and electrostatic precipitators (“ESPs”). The most common SO₂ controls are flue gas desulfurization (“FGD”) systems (commonly called “scrubbers”), which can be either wet (“FGDw”) or dry (“FGDd”). The most common NO_x controls are selective catalytic reduction (“SCR”) systems.

The potential need for additional controls to comply with the Toxics Rule was evaluated for seven different hypothetical configurations of AQC technology at existing EGUs, as presented in Table 2-1. The objective of the assessment was to present the most plausible technologies for each plant configuration to achieve the HAP emission limitations. This analysis does not indicate that all plant configurations will need additional controls; nor does it imply that any particular controls installed at a specific plant will unequivocally meet the emission limitations proposed in the Toxics Rule. The analysis is intended as an overview of commercially available, proven technologies that may potentially be employed in order to lower emissions of the targeted HAP species for a given plant configuration. The analysis took into account cost as well as the performance, maturity level, and number of existing commercial installations of each technology. Selected technologies included different control processes that could be implemented for different fuel types, including opportunities for fuel switching. Additionally, the ability of certain technologies to control multiple HAPs was considered when making final selections.

2.4 Summary of Survey Results

URS identified several alternative control strategies that could be deployed where these hypothetical configurations will likely require additional control for PM, HCl and mercury. Up to four different technologies were identified for each scenario, each of which would provide the additional level of control required. Those technologies were then ranked according to the criteria described above. Table 2-1 lists several alternatives for each configuration requiring additional control. Each facility would choose one of these alternatives to achieve compliance with the Toxics Rule, based on the site-specific conditions at that facility. As the table reflects, many facilities with existing PM and SO₂ controls may need no additional controls to meet the PM and HCl limits in the Toxics Rule, respectively.³ However, if the controls at such facilities

³ These configurations are noted in the table as “no additional control needed.”

are already at their maximum capacity or face other operational challenges, these facilities may indeed need additional controls for PM or HCl as well. Suggestions are provided for upgrades and add-on controls for these outlier plants in the discussion in Section 3.0.

In Table 2-1, configurations that are unlikely to need additional controls to comply with the Toxics Rule are shaded in green. Those likely to require additional controls that can be installed in no more than 24 months are shaded in blue. Those likely to require additional controls that can be typically installed in 36 months (but require more than 24 months) are shaded in yellow. Installation times for new controls are not cumulative. Rather, EGU owners installing multiple control technologies would schedule installation of those controls, and any ancillary modifications to the plant, during the same planned outage, or a coordinated series of outages, provided all controls could be installed prior to the deadline for compliance with the Toxics Rule. Nonetheless, if a particular control cannot be installed prior to this deadline, it is probable that controls necessary for other HAPs would be installed separately, because these control technologies are not, by and large, interdependent.

Section 3.0 of this report provides brief discussions of the rationale behind the various technology selections for each of the hypothetical configurations considered. For each configuration, the report provides strategies for controlling PM, HCl and mercury. Appendix A presents further information on the technologies discussed in this report, including each technology's maturity; the number of commercial installations, if known, the technology's expected performance; capital and operating costs; and the typical schedule for design, installation, and startup.

Table 2-1. Pollution Control Options for Coal- and Oil-Fired Power Plants⁴

Existing Configuration	Control Options to Achieve Toxics Rule Emission Limitations		
	PM	HCl	Hg
Fabric Filter only (§ 3.2)	<i>No additional control needed</i>	1) FGDd; or 2) FGDw; or 3) Dry Sorbent Injection; ⁵ or 4) Coal switch	1) ACI with SO ₃ control; or 2) FGDw with re-emission additives; or 3) Combustion Modification; or 4) Coal switch
Fabric Filter with Wet Flue Gas Desulfurization (§ 3.3)	<i>No additional control needed</i>	<i>No additional control needed</i>	1) ACI with SO ₃ control; or 2) FGD additives; or 3) Bromide addition
Fabric Filter with Dry Flue Gas Desulfurization (§ 3.4)	<i>No additional control needed</i>	<i>No additional control needed</i>	1) ACI with SO ₃ control; or 2) Bromide addition
Fabric Filter with Dry Flue Gas Desulfurization and Selective Catalytic Reduction (§ 3.5)	<i>No additional control needed</i>	<i>No additional control needed</i>	1) ACI with SO ₃ control; or 2) Bromide addition; or 3) Coal switch
Electrostatic Precipitator with Wet Flue Gas Desulfurization and Selective Catalytic Reduction (§ 3.6)	1) ESP upgrade; or 2) Scrubber upgrade; or 3) Toxecon; or 4) Wet ESP	<i>No additional control needed</i>	1) ACI with SO ₃ control; or 2) Bromide addition; or 3) FGDw re-emission additives; or 4) Toxecon
Electrostatic Precipitator only (§ 3.7)	1) ESP upgrade; or 2) Toxecon; or 3) Wet ESP; or 4) FGDw	1) FGDd/FF; or 2) Toxecon w/ Dry Sorbent Injection; or 3) Coal switch; or 4) FGDw	1) Toxecon; or 2) ACI with SO ₃ control; or 3) FGDw + Bromide; or 4) Coal switch
Electrostatic Precipitator with Wet Flue Gas Desulfurization (§ 3.8)	1) ESP upgrade; or 2) FGDw upgrade; or 3) Toxecon	<i>No additional control needed</i>	1) ACI with SO ₃ control; or 2) Bromide addition; or 3) FGDw re-emission additives; or 4) Toxecon

⁴ Green highlighting indicates that additional controls are unlikely to be necessary to achieve Toxics Rule emission limitations. Blue highlighting indicates that the top-ranked control technology has installation times of 24 months or less, after permitting. Yellow highlighting indicates that the top-ranked control technology has typical installation times of more than 24 months but less than 36 months, after permitting.

⁵ Dry sorbent injection includes Trona, hydrated lime, SBS and other reagents.

3.0 Analysis of Control Alternatives

3.1 Overview

With adequate investment, it should be possible for virtually any EGU to comply with all emission limits under the Toxics Rule, but the required strategy for meeting these limits will depend on each plant's existing control configuration. The following sections present seven typical air pollution control configurations at fossil-fuel fired power plants, as listed in Table 2-1. Each regulated HAP (or surrogate) is discussed in terms of the plant configuration and likely controls that may be necessary or useful in achieving EPA's proposed mercury and air toxics limits. Through the reasoning that is presented in the sections below, technologies have been selected as the most likely to assist in meeting EPA's proposed mercury and air toxic standards, as presented in Table 2-1. Technologies discussed in this section are all commercially available technologies with a history of demonstrated performance, and each is capable of achieving compliance with the Toxics Rule. It is acknowledged that site specific factors will impact the ultimate performance of any AQC technology at a given plant. Additional technologies in the developmental stages may be available and have not been included in the scope of this survey. For further detail on these technologies see Appendix A.

3.2 Fabric Filter Configuration

3.2.1 Particulate Matter (PM)

A properly sized and functional FF should provide adequate PM control to comply with the Toxics Rule. If a facility is in need of additional removal, one option would be to add a wet scrubber after the baghouse to remove additional PM as well as HCl. Toxecon could also be added (downstream carbon injection and baghouse) if multi-pollutant control is desired, as this system provides not only additional PM control, but mercury control as well.

3.2.2 Hydrochloric Acid (HCl)

Plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions and with a sufficient additional margin could adequately control emissions of HCl with the installation of a dry FGD system. FGDd would be effective for relatively high HCl content and, for this configuration, would be less costly than FGDw. However, additional PM emissions can be expected with the operation of an FGDd system; therefore, for units with a FF that is not capable of controlling additional PM loadings, a wet FGD would be an effective way to control both HCl and PM.

For plants burning bituminous coal, switching to a western sub-bituminous coal would appreciably reduce HCl emissions. If coal substitution alone does not achieve compliance for these plants, dry sorbent injection will be sufficient to treat the reduced load of HCl. For plants already burning PRB coal and configured with an efficient FF, dry sorbent injection can be expected to reduce HCl emissions sufficiently to meet the Toxics Rule emission standard, and will be significantly less costly than a wet or dry scrubber.

3.2.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions and with a sufficient additional margin, an activated carbon injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, fly ash sales may be impacted by ACI installation upstream of the FF due to increased carbon levels in the collected fly ash. Additionally, under this configuration, control of SO₃, which tends to hinder the effectiveness of ACI Hg removal, may be necessary for effective operation of ACI when burning high sulfur coal.

If mercury re-emissions from the wet FGD system cause the EGU to exceed the Toxics Rule emission limitation, the use of scrubber additives to reduce the re-emissions may be more cost-effective than ACI.

If further Hg control is needed, using Low NO_x Burners or increasing their NO_x removal performance can lead to higher Loss on Ignition (LOI) to the fly ash, and better Hg removal.

Some plants firing bituminous coal might be challenged to achieve Hg emission limitations due to SO₃ interference with sorbent-based mercury control processes. Plants firing lignite (particularly Texas lignite) will require high levels of removal in order to comply with the Toxics Rule. However, in both cases, a switch to western sub-bituminous coal could appreciably lower mercury emissions. In the case of bituminous coals this would be through decreasing flue gas SO₃ concentrations, and thus increasing the performance of ACI for Hg control. For Texas lignite coals, Hg emissions would likely be lowered due to significantly lower fuel Hg concentrations, as well as moderate improvement in ACI performance.

3.3 Fabric Filter and Wet FGD Configuration

3.3.1 Particulate Matter (PM)

Plants equipped with FF and FGDw are unlikely to require additional controls to meet the PM emission limitation in the Toxics Rule. If additional control is required, a plant could upgrade either its fabric filter or scrubber, or both, to achieve the PM emission limitation.

3.3.2 Hydrochloric Acid (HCl)

Plants equipped with FF and FGDw are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule.

3.3.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions with a sufficient additional margin, an activated carbon injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, SO₃ control may be necessary for effective operation of ACI when burning high sulfur coal.

If mercury re-emissions from the wet FGD system cause the EGU to exceed the Toxics Rule emission limitation, the use of scrubber additives may be able to reduce re-emission of mercury more cost-effectively than ACI.

Finally, although less effective without a selective catalytic reduction (SCR) system, bromine addition could be sufficient for trimming emissions at EGUs firing low sulfur coal if the Hg emission rate needs only small incremental improvement.

3.4 Fabric Filter-Dry FGD Configuration

3.4.1 Particulate Matter (PM)

Plants equipped with FF and FGDd are unlikely to require additional controls to meet the PM emission limitation in the Toxics Rule. If additional control is required, a plant could upgrade either its fabric filter or scrubber, or both, to achieve the PM emission limitation.

3.4.2 Hydrochloric Acid (HCl)

Plants equipped with FF and FGDd are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. However, if needed, a dry sorbent injection system would provide a low capital option to trim emissions.

3.4.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions with a sufficient additional margin, an Activated Carbon Injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, SO₃ control may be necessary for effective operation of ACI when burning high sulfur coal.

Finally, although less effective without a selective catalytic reduction (SCR) system, bromide addition could be sufficient for trimming emissions at EGUs firing low sulfur coal if the Hg emission rate needs only small incremental improvement.

3.5 SCR-FGDd-FF Configuration

3.5.1 Particulate Matter (PM)

Plants equipped with SCR, FF and FGDd are unlikely to require additional controls to meet the PM emission limitation in the Toxics Rule. If additional control is required, a plant could upgrade either its FF or scrubber, or both, to achieve the PM emission limitation.

3.5.2 Hydrochloric Acid (HCl)

Plants equipped with SCR, FF and FGDd are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. If necessary, removal rates would be improved by either upgrading the scrubber or installing a dry sorbent injection system.

3.5.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions with a sufficient margin, an activated carbon injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, SO₃ control may be necessary for effective operation of ACI when burning high sulfur coal.

Removal rates of Hg from bromide addition are high in combination with the SCR, especially for PRB coal, and could also provide polishing capability for bituminous coals that require only incremental improvements in removal. However, the SCR, FGDd, FF configuration is not typical for plants firing bituminous coal. If installed on a bituminous coal plant, it is possible that mercury control performance could be constrained by elevated SO₃ levels. A switch to Western sub-bituminous coal would improve the performance of the plant's various mercury controls as well as yield acid gas emission reductions.

3.6 SCR-ESP-Wet FGD Configuration

3.6.1 Particulate Matter (PM)

The compliance strategy for PM under this configuration will depend on the performance of existing controls. Assuming the existing ESP does not provide adequate control to meet the Toxics Rule emission limitation, the first option to provide additional control would be an upgrade of the ESP, the scrubber mist eliminator, or both. Alternatively, a wet ESP may be installed. Toxecon could also be added downstream of the existing ESP if multi-pollutant control is desired.

3.6.2 Hydrochloric Acid (HCl)

Plants equipped with a high-efficiency wet FGD system are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. If additional removal is needed, removal efficiencies could be improved by one or more of the FGD upgrades described in Appendix A.

3.6.3 Mercury (Hg)

The Hg control strategy under this configuration would depend on the fuel being fired. The primary choice for plants firing bituminous coal would likely be ACI with additional SO₃ control technology; some plants with this configuration might not require any additional mercury control. For plants firing low-sulfur fuels, the primary choice would likely be bromine addition. For plants requiring additional PM control, or desiring Hg removal upstream of the FGD system, Toxecon with activated carbon injection would likely be the best control strategy. Under this configuration, scrubber re-emissions additives may be required to control Hg emissions in conjunction with other control technology, depending on mercury removal performance of the wet FGD.

3.7 ESP Only Configuration

3.7.1 Particulate Matter (PM)

The compliance strategy for PM under this configuration will depend on the performance of existing controls. Assuming the existing ESP does not provide adequate control to meet the Toxics Rule emission limitation, the first option for additional control would be an upgrade of the ESP. Alternatively, a wet ESP may be installed. Toxecon could also be added downstream of the existing ESP if multi-pollutant control is desired. In some cases, particularly plants burning bituminous fuels, a wet FGD may be installed if additional SO₂ control is also desired.

3.7.2 Hydrochloric Acid (HCl)

A dry FGD system will provide effective control for relatively high HCl content, but may require installation of a fabric filter to control the additional particulate loadings dry FGD would add. A dry FGD system is likely to be more cost effective than a wet FGD, if switching to a FF to handle the additional particulate loading is not necessary. Toxecon used in conjunction with sorbent injection would be a viable control option if multi-pollutant control is desired. For plants firing bituminous coal, a switch to a western coal would reduce the HCl loading on the ESP, likely enabling dry sorbent injection alone to achieve the Toxics Rule emission limitation.

3.7.3 Mercury (Hg)

The Hg control strategy under this configuration would depend on the fuel being fired. For plants burning western coals, or those requiring additional PM control or desiring Hg removal upstream of the FGD system, Toxecon with activated carbon injection would likely be the best control strategy. Alternatively, an ACI system using brominated sorbent may be used for plants burning western coals; however, mercury removal under this option depends on ESP performance. Installation of a wet FGD may be a viable option for plants that desire additional SO₂ control; using this strategy, bromide addition may also be an option for mercury control for EGUs firing western fuels.

The primary choice for a plant firing bituminous coal would likely be an ACI with additional SO₃ control technology. However, plants firing bituminous coal will be challenged to achieve desired mercury reductions due to SO₃ interference. Plants firing lignite containing high mercury levels (e.g., Texas lignite) will require high levels of removal which are difficult to obtain across an ESP. In both cases, a switch to a low-sulfur sub-bituminous coal would lower mercury emissions via better mercury control performance and, for Texas lignite fired EGUs, lower coal mercury levels.

3.8 ESP-FGDw Configuration

3.8.1 Particulate Matter (PM)

The compliance strategy for PM under this configuration will depend on the performance of existing controls. Assuming the existing ESP does not provide adequate control to meet the Toxics Rule emission limitation, the first option to provide additional control would be an upgrade of the ESP, the scrubber mist eliminator, or both. Alternatively, Toxecon could also be added downstream of the existing ESP if multi-pollutant control is desired.

3.8.2 Hydrochloric Acid (HCl)

Plants equipped with a high-efficiency wet FGD system are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. If additional removal is needed, removal efficiencies could be improved by one or more of the FGD upgrades described in Appendix A or by a dry sorbent injection system.

3.8.3 Mercury (Hg)

The Hg control strategy under this configuration would depend on the fuel being fired. For plants requiring additional PM control or desiring Hg removal upstream of the FGD system, Toxecon with activated carbon injection would likely be the best control strategy. Bromine addition would likely be the primary control strategy for plants burning low-sulfur fuels. Alternatively, for plants burning low-sulfur fuel, ACI is another control option. ACI would also be an option for plants firing bituminous coal, but SO₃ control technology may be necessary. Under this configuration, scrubber re-emission additives may be required to control Hg emissions in conjunction with other control technology, depending on mercury removal performance of the wet FGD.

3.9 Installation Schedule

None of the typical configurations considered in this assessment included existing mercury controls, though many EGUs are presently equipped with ACI. Accordingly, this analysis concludes that every EGU configuration would require mercury control, and identifies ACI as the technology of choice for six of the seven configurations considered. ACI has a typical installation time of 12 to 18 months after permitting. As URS assumes fabric filters to provide adequate PM control to comply with the Toxics Rule PM emission limitation, ESP upgrades are the top-ranked alternative for improving PM control from EGUs. Depending on the scope of the upgrade, installation times for ESP upgrades typically run from six months for the simpler upgrades to twenty-four months for the most comprehensive upgrades. Dry FGD technology, with a typical installation time of 24 to 36 months, was identified as the top-ranked

technology for only two of the seven configurations evaluated. Dry FGD has the longest installation time of the top-ranked technologies.

These installation times are not cumulative; rather, plants installing multiple technologies would typically coordinate installation so that all controls for mercury, HCl and PM would be installed during the same outage, although some additional outage time may be necessary to coordinate simultaneous installation. With nearly four years between the proposal of the Toxics Rule and the date EGUs must come into compliance, these improvements can be accomplished on-time, provided EGU owners move quickly to initiate these upgrades in response to the proposed rule, and no unreasonable delays occur in the permitting process or supply chain.⁶

4.0 Conclusion

Using the emission limitations proposed by EPA in the Toxics Rule as its guide, URS examined the existing field of demonstrated, available AQC technologies to determine whether these technologies would be sufficient to allow typical coal-fired and oil-fired EGUs to achieve these emission limitations. URS concluded that the emission limitations proposed in the Toxics Rule can be achieved by typical EGUs through the application of successfully demonstrated, available AQC technologies. The controls considered in this analysis can typically be installed in 18 months (for ACI), 24 months (for ESP upgrades), or 36 months (for FGDs) after detailed design and permitting is complete. If EGU owners make their technology choices and initiate the permitting process promptly, they should be able to comply with the Toxics Rule emission limits by the deadline of early 2015 (almost 48 months after proposal of the rule). Plants facing extreme delays in permitting or the supply chain, or with atypically complex upgrade requirements, have an opportunity to request an additional year to come into compliance with the Toxics Rule.

⁶ Potential delays associated with heavy equipment lead times have not been included in this analysis because it is not possible to predict at this time whether any particular delay will occur.

APPENDIX A

A.0 Technology Descriptions

This section provides a high-level overview of each add-on control technology that has been presented in the main body of this report. Because some of these technologies treat multiple HAPs, they cannot easily be categorized by the pollutant they treat. However, several of the technologies described are upgrades or modifications to AQC systems present at existing EGUs. These modifications are grouped separately from technologies not considered in the hypothetical configurations discussed in Section 3.0 of the report.

Equipment costs provided in the following technology descriptions are typical; site specific circumstances may lead to higher or lower costs due to site specific requirements. Additionally, cost estimates include equipment and operating costs, where specified; planning and financing costs are not included. The estimated schedules for implementation of the technologies represent time from the placement of the equipment order to installation. This assessment is based on cost and schedule information available today, and the estimates provided here may be affected by future changes in pricing and scheduling demand.

A.1 Modifications to Existing AQC Systems at EGUs

A.1.1 Cold-side ESP Upgrades

The use of electrostatic precipitator (ESP) technology for the removal of PM is well established and has been implemented for over 100 years. Decades old, or poorly performing ESPs that were designed for lower emission performance can be upgraded to improve collection efficiency and reduce operating costs. Often the performance can be increased through a thorough examination to insure that worn or broken components are replaced, and insuring that the gas flow distribution through the system is uniform. Other ESP modifications and upgrades may include:

- Upgrade of control systems such as power controlled rapping (PCR). \$0.27/kW
- Upgrade of ESP power supplies. \$1/kW
- Add SO₃ and/or ammonia injection (to the flue gas upstream of the ESP) to improve ash agglomeration. \$2-10/kW
- Replace wire and weight systems, widening the gas passages and adding rigid discharge electrodes. This will improve the mechanical integrity of the electrodes and can improve performance with existing TR sets.
- Increase the number of electrical bus sections.
- Add rappers to decrease the amount of collecting surface area served by each rapper

- Increase the collecting surface area - several vendors report that many of the older ESPs in the US can be modified to increase the collecting surface area by 10-20% within their existing footprint. Another option is to add an additional field. \$30-0/kW
- Reduce gas flow through the ESP by repairing upstream leaks or upgrading air heaters to limit air in-leakage
- Add a Bipolar Agglomerator to the inlet of the ESP. \$25-40/kW.

The capital costs associated with these upgrades will depend on the extent to which the ESP is modified. If the unit is particularly old or poorly performing, more repairs or modifications may be necessary. Some vendors claim that modifications such as upgrading the power supplies and controls will pay for themselves within one to two years due to savings in power consumption. Operating costs for many of these modifications will not increase over the cost of previous operation, and in many cases the operating costs will decrease due to gains in collection and power consumption efficiency. The operating costs for injecting SO₃ and/or ammonia for ash conditioning will be approximately 2-4 \$/kW-yr.

Another method to improve the performance of an ESP would be to add a Bipolar Agglomerator to the ESP inlet duct. An agglomerator manufactured by Indigo Technologies uses a bipolar charging zone to charge part of the dust positively and part of the dust negatively. This is accomplished by passing the flue gas through a series of alternating positive and negative parallel passages. The dust then enters a mixing zone where the oppositely charged particles are attracted to each other and form a larger agglomerated particle that can be more easily removed in the ESP. The agglomerator is similar to an ESP without collection plates. This technology is relatively new with only 45 commercial installations at power plants, mostly outside the U.S. Reductions in opacity are reported to be 40% to 70%, with some units burning sub-bituminous and bituminous fuels reporting reductions in opacity of approximately 50%. The cost to add an agglomerator to an existing system is approximately \$25-40/kW. The operating costs are approximately \$0.02/kW-yr and consist primarily of the power required to operate the unit.

- ESP Upgrade Technology Maturity: mature
- Number of Units Upgraded: hundreds
- Expected Performance:
 - PM: +99%
- Capital Costs: 0.27 - 20 \$/kW
- Operating Costs: .02- 4 \$/kW-yr.
- Installation Schedule: 6-12 months from award of design to operation for low capital options; 12-24 months for implementation of higher capital cost modifications / additions
 - **Outage Required:** 0-7 days if no plate/electrode modification. 2-4 weeks with plate/electrode modification.

A.1.2 Fabric Filter Upgrades

A typical fabric filter should be able to meet MACT PM emission standards. If a plant is unable to meet emission standards with a fabric filter, the cause is most likely due to bag failures. To minimize bag failures it may be possible to optimize the cleaning process to minimize these problems. On a pulse jet baghouse this may include adjusting the pulse pressure and duration to more thoroughly clean the bags. By cleaning more thoroughly, the interval between cleaning may be reduced and the life of the bags could be extended. Optimization of fabric filter performance may also be achieved by an evaluation of the maintenance schedule. An analysis of process and maintenance data could lead to an understanding of how to anticipate bag failure and replace them before the failure actually occurs.

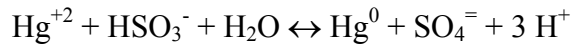
Another alternative to increase PM collection would be to replace the existing bags with different material such as a membrane bag. Different bag materials will have different pressure drop characteristics and it will be necessary to determine whether the plant has existing fan capacity to handle the upgrade.

An additional solution would be to add additional compartments to the existing baghouse to increase the collection surface, or add a COHPAC system. The Toxecon could be necessary if a multi-pollutant strategy is desired and it is advantageous to maintain fly ash sales from the existing baghouse. Adding additional compartments or a Toxecon system are both capital intensive solutions and may not be practical for plants that have restricted space available for retrofit.

- **Technology Maturity:** mature (fabric filter)
- **Number of Commercial Installations:** many
- **Expected Performance:**
 - PM: +99%
- **Costs for Optimizing Fabric Filter Performance:** \$200K - \$500K, excluding projects where complete bag replacement is required
- **Schedule:** 3-6 months for performance optimization
- **Costs for Adding Compartments or Toxecon:** 75-130 \$/kW
- **Schedule:** 12-24 months from detailed design to startup
 - **Outage Required:** 7-10 days. (3-4 weeks if a new fan is required)

A.1.3 FGDw Additives

As discussed in Section 1.2.8, wet scrubbers can remove acid gases, PM and mercury. However, removal of Hg^{+2} by wet FGD systems can be limited by a phenomenon called “re-emission” that results in a portion of the scrubbed Hg^{+2} being chemically reduced to Hg^0 in the FGD liquor. Once reduced, the insoluble Hg^0 is released back into the flue gas. The re-emission process is not currently well understood, but is believed to occur by reaction with bisulfite ions (dissolved SO_2 at lower Ph) in the FGD liquor, according to the following overall reaction:

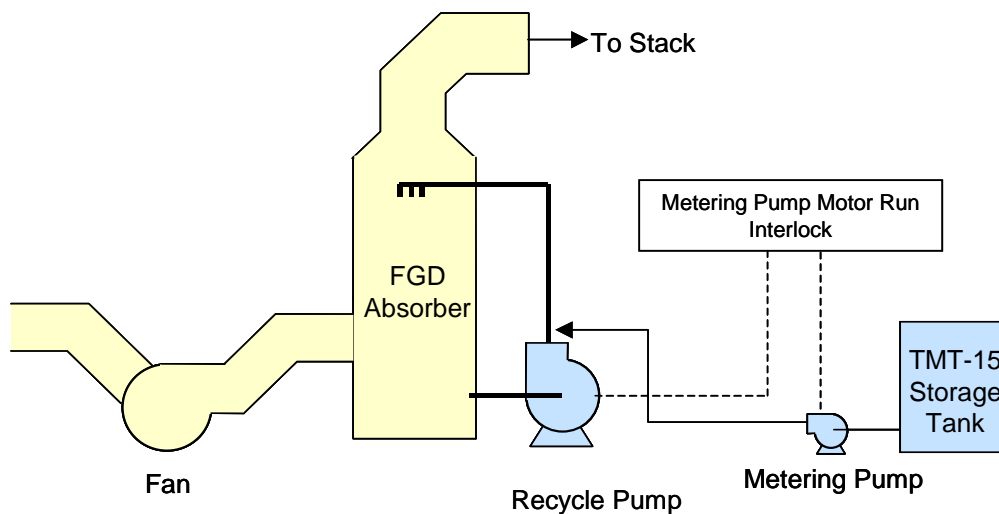


The main pathway for this reaction is believed to be through the formation of complexes between Hg^{+2} , sulfite, chloride, and possibly thiosulfate ions (present in inhibited oxidation FGD systems). Even in forced oxidation FGD systems, there can be sufficient sulfite present for re-emission reactions to occur. As more is understood, it may be possible to control FGD chemistry to minimize re-emission (e.g., by controlling forced oxidation air rates and/or liquor chloride concentrations). However, a near-term solution may be the use of FGD additives to precipitate Hg^{+2} out of the liquid phase before it undergoes reduction reactions.

Additives generally work by rapidly precipitating oxidized mercury from the FGD liquor, so it will not react with other liquid-phase species such as sulfite ions and be reduced to the elemental form. Most additives contain sulfides, which produce a very insoluble salt with oxidized mercury.

The most straightforward method of adding sulfides to FGD systems might be to introduce H_2S into the scrubbed gas upstream of the FGD absorber. However, H_2S is extremely toxic and most utilities would not want to handle this gas at their plants. Another approach is to add sulfide-containing salts to the FGD liquor. However, some of these salts can release H_2S if they are exposed to low Ph, aqueous conditions. Four commercially available additives are discussed below: Degussa's TMT-15, Nalco's additive 8034, Babcock & Wilcox's sodium hydrosulfide (NaHS) additive, and Solucorp's IFS-2C additive. Figure A-1 shows a schematic for a sample TMT-15 addition system.

Figure A-1. TMT-15 Additive System for FGD Absorber with One Recycle Pump



One operational issue that has not fully been addressed is the impact of re-emission additives on gypsum Hg content. Some owners of FGDw systems sell the gypsum that is produced as a byproduct of the scrubber. An increase in the mercury content of the gypsum byproduct could affect sales of the product. Currently there are few if any specifications on gypsum Hg content, but re-emission additives that precipitate mercury could increase gypsum Hg content to the point where the gypsum would potentially no longer be salable. If this is the case, the effective cost of re-emission additives would increase for those FGDw operators who are no longer able to sell the gypsum byproduct for \$5-10/ton, but rather a liability costing \$5-20/ton to dispose of in a landfill.

- **Technology Maturity:** Testing 3 years of experience
- **Number of Commercial Installations:** Several, in Europe
- **Expected Performance:**
 - Hg – An additional 10-50% above native capture
- **Capital Costs:** 0.75-1.5 \$/Kw
- **Operating Costs:** 0.2-0.5 \$/Kw-yr.
- **Installation Schedule:** 6-9 months for design, installation, and parametric testing.
 - **Outage Required:** None.

A.1.4 Flue Gas Desulfurization (FGD) Upgrades

Existing FGD scrubber units can be modified to enhance SO₂ removal performance and improve unit operations and reliability. Such modifications are applicable to older FGD units, units currently not being operated (i.e., moth-balled units) or units originally designed for lower removals than now required or desired. The extent of a given upgrade process is typically a function of the required performance levels, configuration and condition of the existing absorber, and other site-specific balance-of-plant requirements.

Upgrades to a scrubber can offer an appreciable cost advantage over replacing an existing FGD unit with either a new unit or an alternative air quality control technology. This is achieved by salvaging as many structural components and equipment associated with the existing unit as possible. This includes reuse of existing structural steel and absorber shells as well as high-capital process equipment such as pumps and compressors (where applicable).

Upgrades have been performed on a large number of FGD units over the past 15 years and have resulted in increased SO₂ removal performance to levels ranging from 92 – 99%. These have ranged from minor modifications to the internal components of a given unit, to enhance gas-liquid contact, to conversion of some units from one FGD technology to another coupled with the addition or modification of various balance-of-plant equipment or processes. An example of a technology conversion could include modifications to change a dual-alkali scrubber to a limestone forced-oxidation unit.

Because of the large variation of activities and associated costs that are possible within the range of scrubber modifications that can be implemented, it is convenient to classify upgrades into three different categories, as described below.

- **Minor Upgrades:** These consist of moderate changes to some of the internals of a scrubber module, reusing most of existing process and structural components. The primary focus is enhancement of gas/liquid contacting within the absorber. Examples of applicable modifications include installation of absorber trays or wall rings as well as modifications to the configuration or type of reagent spray headers used (to improve overall reagent coverage and overlap within the absorber). Typical minor upgrades have been used to boost FGD performance to 92 – 97% SO₂ removal.
- **Moderate Upgrades:** These upgrades typically consist of major overhauls to the internals of a scrubber module to replace poor performing or failing components. In many cases, the existing internal process and structural components are removed; the absorber shell and large equipment components are maintained. Modifications include installation of new and improved reagent spray header arrays and absorber trays.
- **Major Upgrades:** For some old FGD units, systems operating with lower-efficiency technologies and units that have been out of commission for extended periods of time, major upgrades are required obtain desired levels of performance. Such upgrades typically involve the same activities described for moderate upgrades, but can also include additional replacement of some large equipment along with modifications or additions associated with balance-of-plant equipment. The latter can include additions of or modifications to reagent preparation systems (e.g., ball mills), byproduct dewatering systems, and process slurry recirculation systems. In some cases, enhancements are made to existing mist eliminators to reduce carry-over of particulate material from the scrubber. Conversions from one FGD technology to another may include demolition of old or unneeded process components and/or addition of new ones.

The costs associated with FGD system upgrades are commensurate with the level of capital improvements or replacements required for a specific unit. The costs for minor upgrades typically range from \$5 - \$10/kW, whereas moderate upgrades typically range from \$15 - \$25/kW. The costs for major upgrades can be quite variable, depending on the nature of upgrade and extent of balance-of-plant modifications made; these upgrades typically range from \$50 to no more than \$100/kW. The pending EPA MACT rule coupled with the multi-pollutant control nature of wet FGD scrubbers should ensure that scrubber upgrades continue to be a feasible option for many plants to enhance emission reductions.

The impact of a scrubber upgrade on unit operating costs is determined by the nature of the modification(s). Changes in reagent preparation and process transport costs are impacted by the nature of the modifications made to preparation equipment, recirculation lines, and spray headers. For example, increased pressure-drop across the reagent slurry recirculation system (i.e., due to increased number of spray headers) would result in increased energy costs to operate the process. The addition of improved contactors within the absorber vessel may enable slurry

liquid-to-gas ratios to be reduced, thus having an opposite effect on costs. The addition of new processes associated with byproduct dewatering or water treatment would increase operating costs to varying degrees. A transition to a zero water discharge (ZWD) system could result in elimination of the need for a water treatment system, thus having the opposite effect; however, this benefit would be off-set by higher capital cost and energy usage required for the ZWD scheme. Furthermore, the conversion to an FGD process that produces a marketable gypsum byproduct could result in an appreciable revenue stream for the plant if local market conditions are favorable. Thus, operating cost impacts of scrubber upgrades can vary substantially from plant to plant, ranging from actually reducing operating costs to significantly increasing operating costs, depending on the nature of the existing and modified units.

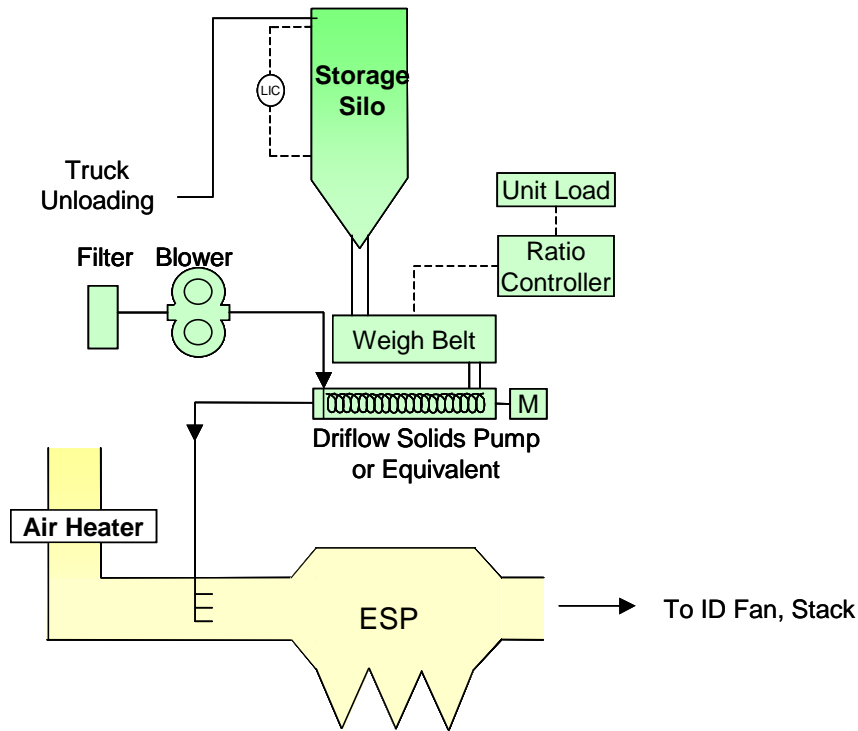
- **Technology Maturity:** FGD scrubber upgrades have been conducted over 15 years.
- **Number of Commercial Installations:** Approximately 50 FGD units have been upgraded to enhance performance or lower overall operating costs.
- **Expected Performance:**
 - SO₂: Upgraded FGD scrubbers have SO₂ removal rates of 92 – 99%.
 - PM: High-efficiency FGD units can typically remove up to 70% of the particulate material entering the absorber in the flue gas.
 - HCl: Most well-performing wet FGD units are able to achieve greater than 90% removal of hydrogen halides. HCl would be expected to be removed across a wet FGD unit at a similar or higher efficiency than SO₂.
- **Capital Costs:**
 - Minor Upgrades: \$5 - \$10/kW
 - Moderate Upgrades: \$15 - \$25/kW
 - Major Upgrades: \$50 - \$100/kW
- **Operating Costs:**
 - Variable (see discussion above)
- **Installation Schedule:** Typical schedules for the design, installation, and startup of FGD upgrades range from 12 – 36 months.
 - **Outage Required:** 4-8 weeks, in two parts.

A.2 Additional AQC Technologies and Process Changes

A.2.1 Activated Carbon Injection (ACI)

Activated carbon injection (ACI) is the most demonstrated of the add-on mercury control technologies considered. Figure A-2 illustrates how ACI would be implemented upstream of a cold-side ESP (injection upstream of a FF baghouse would look similar, except for exchanging a baghouse for the ESP). Sorbent is metered from a storage silo with a weigh belt or volumetric feeder. A blower provides the motive force to convey the sorbent from the feeder to the flue gas duct. The sorbent is injected into the flue gas duct via a series of injection lances. The lances are placed upstream of the PM control device (PCD) or in rare cases upstream of the air heater.

Figure A-2. Simplified Schematic of ACI Installation.



The performance of ACI for mercury control can be very site specific. Factors such as duct residence time, mixing effectiveness, PCD size and type, flue gas temperature, flue gas HCl concentration, concentrations of competing species in the flue gas (e.g., SO₃) and other factors make it difficult to use full-scale performance data from one site to predict performance at another. Each of these parameters is explored below in somewhat more detail.

- The more important design factor for the lances is the promotion of mixing between the activated carbon and the flue gas. Better mixing can be achieved through nozzle design on the lances and careful lance placement. These parameters can be optimized with the help of computational fluid dynamics (CFD) modeling, in which the trajectory of the injected sorbent particles is computed throughout the flue gas path.
- PCD size can be important because carbon/ash carryover from small PCDs can limit the injection rate. Carbon carryover has been visually observed on PM filters placed at the outlet of small and large ESPs, but quantification of the carryover is difficult. URS experience with ACI in front of one small ESP (SCA = 173 ft²/kacfm) (DOE project DE-FC26-03NT41987) showed that the injected carbon adversely affected ESP sparking, due to carbon tracking on insulators. Increased sparking could limit the amount of carbon that can be injected and hence the mercury capture that can be achieved.
- ACI performance is best at lower flue gas temperatures (<300°F). Carbons are being developed for high temperature applications, such as Sorbent Technologies' H-PAC. At temperatures below 650°F, H-PAC is reputed to have the same mercury removal performance as Sorbent Technologies' standard brominated carbon B-PAC.

- Activated carbon injection performs poorly in flue gas with high SO₃ concentrations, such as flue gas derived from eastern bituminous coals. The SO₃ competes with mercury for adsorption sites on the activated carbon. SO₃ tolerant sorbents (discussed below) and SO₃ mitigation technologies (discussed in a previous section) are possible means to make ACI more effective for bituminous flue gas.
- For low-halogen flue gas, brominated sorbents can offer significantly higher mercury removal than standard activated carbons. Brominated carbons have shown only a small advantage for high chloride flue gas, likely because SO₃ concentrations are high in these types of gases.

There are no data to predict the long-term effects of a permanent activated carbon injection process that is in operation for several years. As noted above, increased sparking has been observed on small ESPs. Carbon breakthrough has been observed on both small and large ESPs. Carbon breakthrough may compromise gypsum quality for units that are equipped with wet FGDs downstream of the ESP. Carbon breakthrough may also trigger New Source Review for units that do not have additional PM controls downstream of the ESP.

A disadvantage of using ACI for mercury control is that the carbon in the fly ash can adversely affect the air entrainment capabilities of concretes made using fly ash to replace some of the cement. The carbon sorbent in the fly ash competitively adsorbs the air-entraining admixtures (AEAs) that are added to concrete for air entrainment and stabilization. This competition results in a larger volume of AEA being needed, and more significantly to ready-mix concrete manufacturers, it results in variability in the amount of AEA needed.

- **Technology Maturity:** Testing & Full Scale Operation; ~10 & 2 years of experience
- **Number of Commercial Installations:** 50+
- **Expected Performance:**
 - Hg – An additional 10-90% above native capture
- **Capital Costs:** 2-10 \$/kW (depending upon unit size)
- **Operating Costs:** 2-20 \$/kW-yr.
- **Installation Schedule:** 12-18 months for design, installation, and parametric testing.
 - **Outage Required:** None.

A.2.2 Dry Sorbent Injection (“DSI”)

Sorbent materials can be injected at various points along the flue gas path to control acid gases. The main target of this technology is SO₃; however additional acids may also be removed such as HCl, HF, and SO₂. The removal of these additional gases depends on the amount and type of material added to the system. Sorbent reagents can be injected either as slurry or as a dry material. Slurry is typically injected using dual fluid nozzles where the water evaporates upon injection leaving dry sorbent material to react with the acid gases in the flue gas. Dry material is injected using pneumatic conveyors to carry the material to the injection point. Sorbent injection

is a mature technology with approximately 90 units currently being treated with one of five main reagents:

- Trona – (22 units) dry injection of a mined mineral consisting of sodium bicarbonate and sodium carbonate
- SBS – (20 units) liquid injection of soda ash or sodium bisulfite
- Hydrated Lime – (28-34 units) dry injection
- Magnesium Hydroxide – (1 unit) slurry
- Ammonia – (8 units) anhydrous or aqueous

Sorbents can be injected at several locations along the flue gas path including into the boiler, before an SCR, before the air heater, before the ESP or fabric filter, or before an FGD system. Table A-1 illustrates injection locations for each Sorbent material and includes the typical SO₃ removal rate at normalized stoichiometric ratios (NSR) of reagent to SO₃. Ammonia is currently used to condition fly ash for removal in an ESP, and could be used for SO₃ control; however the stoichiometric ratio must be carefully regulated to prevent excess ammonia emissions. This may be an attractive option for plants with an existing SCR and infrastructure for ammonia storage on site.

Table A-1. Injection Locations, SO₃ Removal, and Required Stoichiometric Ratio

<i>Typical Injection Location</i>	Trona	SBS Injection	Hydrated Lime	Magnesium Hydroxide	Ammonia
Boiler				•	
Before SCR		•			
Before AH	•	•		•	
Before ESP/FF	•		•		•
Before FGD			•		
Typical SO ₃ Removal	70-90%	95-99%	50-80%	50-90%	80-95%
Typical NSR	2-3	1-1.5	3-5	2-4	1.5-2

The typical capital cost for this technology is about \$10/kW with the exception of ammonia injection that is approximately \$5/kW. This includes pumps, spray nozzles, and control equipment. The operating costs consist of the reagent, maintenance, water, and parasitic power costs. A majority of the operating cost (~80%) consists of the reagent feed stock, thus making the overall operating cost dependent upon the normalized stoichiometric ratio necessary to get the desired removal rate. The NSR listed in the table above is for SO₃, additional reagent will be necessary to capture HCl and HF in some plant configurations. SO₂ capture is also possible by injecting excess reagent; however the PM collection device must be capable of handling the increased PM load, which may be 50-80% greater than the fly ash alone. Table A-2 contains a summary of conceptual capital and approximate costs.

Table A-2. Capital and Operating Costs for Dry Sorbent Injection

	Trona	SBS Injection	Hydrated Lime	Magnesium Hydroxide	Ammonia
Capital Cost (\$/kW)	10	10	10	10	5
Reagent Cost (\$/ton)	180	275	125	500	600
Approx. Operating Costs for SO ₃ and HCl capture (\$/kW-yr.)	3.4 - 5	2 - 2.75	2 - 3	5.1 - 8.6	2.2 - 3.5

- **Technology Maturity:** mature; 7+ years of operating experience
- **Number of Commercial Installations:** 90
- **Expected Performance:**
 - SO₃ – 50 - 99% depending on reagent, injection rate and configuration
 - HCl, HF – up to +90%
 - SO₂ – 40 - 90% possible
 - Hg – enhances ACI performance by removing SO₃ especially in bituminous flue gas
- **Capital Costs:** 5 - 10 \$/kW
- **Operating Costs:** 2 - 8.6 \$/kW-yr. (SO₃ only)
- **Installation Schedule:** 9-12 months from award to commercial operation
 - **Outage Required:** None.

A.2.3 Coal Switching

With upcoming MACT limits on HCl and mercury emissions at coal fired power plants, there are several scenarios where coal switching may be a cost-effective option for meeting emission limits, rather than the installation of pollution control devices. There are likely to be two dominant cases where coal switching is a viable option for meeting the upcoming MACT standards:

- Switching from an Eastern bituminous or Lignite coal to a Powder River Basin (PRB) coal to meet HCl emissions limits.
- Switching from Lignite (Texas-derived in particular) to a PRB coal to meet mercury emissions limits.

For units switching from bituminous coal, it is recognized that the feasibility would depend on the ability of a given plant to operate either with higher coal flow (and associated flue gas volume) or at a de-rated capacity.

Without some form of scrubber (wet or dry) it is unlikely that a plant burning eastern bituminous coal could meet the potential HCl emission limits. Installation of a new FGD system or a significant overhaul of an existing FGD system would be capital intensive project, and cost approximately \$100/Kw or more. PRB coals have approximately 20-100 times less chloride and

4-10 times less sulfur than eastern bituminous coals. By switching to a PRB coal, it could be possible to meet

HCl emission limits by using a less expensive HCl control technology like alkaline injection. For this switch to be economically favorable, the following would have to be true:

- The site burns eastern bituminous or a lignite coal with significant chloride and sulfur content.
 - The site does not have any HCl control technologies in place, or has a significantly under-performing HCl control technology that would need a significant overhaul to meet HCl emissions limits.
 - The site has a FF or ESP that can handle additional PM loading from alkaline injection for HCl removal. A FF would be more effective in removing HCl with alkaline injection than an ESP, and would also likely be more able to meet PM emissions limits even with the additional PM load.

Due to the high content of mercury in lignite, it is unlikely that a plant using lignite as its only fuel source would economically be able to meet a non-coal specific mercury emission limit. Therefore, complete fuel switching, or if significant pollution control equipment was already in place with high native capture (SCR, FF, FGD), fuel blending would be necessary to meet the emissions limits. Due to similar energy content, availability, and relatively low cost, the most likely candidate for an alternate fuel is PRB coal.

A.2.4 Combustion Modifications

Boiler combustion modifications may be used to optimize mercury capture by unburned carbon, which is subsequently collected along with fly ash in the ESP. It has been observed in limited field testing reports that for bituminous coal fired plants significant mercury control percentages (up to 75%) can be achieved with fly ash having elevated LOI values.⁷

One research organization, G.E. Environmental Services, has conducted full-scale tests on using combustion modifications to optimize this effect. The full-scale tests were co-funded by the U.S. Department of Energy. One project (DE-FC26-03NT41725) has employed coal “re-burning” to optimize mercury capture, while the other (DE-FC26-05NT42310) is investigating air staging using (separated over-fire air [SOFA]).

In the first demonstration project, GE reported up to 60% mercury removal with optimized re-burning and 10-15% LOI in the fly ash at a 300°F ESP inlet flue gas temperature. They reported up to 75% mercury removal at similar conditions, but with a lower, 270°F ESP inlet temperature. In the second project on a 200-MW tangentially-fired unit, GE reports that

⁷ Lissianski, Vitali. “Mercury Control Using Combustion Staging”. Presented at DOE-NETL Mercury Control Technology R&D Program Review. Pittsburgh, PA. July 13, 2005.

optimized SOFA achieved up to 65% mercury removal with about 5% LOI in the fly ash at a 300°F ESP inlet temperature. They reported a strong effect of flue gas temperature on mercury capture by LOI, and tested duct humidification as a means of lowering the ESP inlet flue gas temperature.

The Lehigh University Energy Research Center also has been investigating the effects of boiler combustion modifications on mercury emissions. They have developed a predictive model, and have conducted full-scale tests at three eastern-bituminous-coal-fired units, ranging from 108- to 650-MW in size. Two sites also fire some imported coals. In testing on a 250-MW tangentially fired boiler, they were able to enhance capture of mercury with the fly ash from a baseline level of about 6% to about 60% with “optimum” low mercury settings and a mid-level excess oxygen value. Variables optimized included excess oxygen, coal mills in service, mill classifier setting, separated over-fire air (SOFA) percentages, burner and SOFA tilt, air heater exit temperatures, and flue gas residence time prior to PM removal. The latter was accomplished by de-energizing an old ESP upstream of a new, larger ESP. However, the 60% mercury reduction level was achieved in some tests without de-energizing the old ESP.

Combustion modification, to increase mercury capture, will increase carbon content in the fly ash. If the ash is being sold, increased carbon content could either reduce the value or render the ash unsalable. Such costs can be significant when ash goes from being a commodity worth \$5-20/ton to a liability costing \$5-20/ton to dispose of in a landfill.

There are not many studies available on combustion modification and its impact on mercury removal on PRB coal fired power plants. Part of this is due to the general efficiency in combustion of PRB coals, and that achieving an LOI of greater than 1 wt% is difficult. Due to low SO₃ concentrations in the flue gas and the highly alkaline ash, even small increases in LOI have been shown to increase Hg capture.

Based on the evidence at hand, combustion modification may possibly be used for mercury control either in conjunction with another mercury control technology when native capture is low, or as a way of increasing a high native removal such that no other mercury control technologies are necessary. Combustion modification will be most effective if a baghouse is used for PM capture, as increased LOI will be more effective with fabric filters than with ESPs.

- **Technology Maturity:** Testing; ~10 years of operating experience
- **Number of Commercial Installations:** few operating
- **Expected Performance:**
 - NO_x – 0-20% additional removal
 - Hg – An additional 10-50% above native capture
- **Capital Costs:** 0.5-1 \$/kW (Study necessary to “tune”)
- **Operating Costs:** 0.2-1 \$/kW-yr. (<http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter5.pdf>)

- **Installation Schedule:** 3-6 months for experimental design and “tuning” of the combustion tests.
 - **Outage Required:** None.

A.2.5 Dry Flue Gas Desulfurization

Dry FGD (also referred to as a “spray dryer”) is typically employed for the removal of SO₂ emissions, but may also be used to accomplish removal of acid gases and selenium. Removal of these additional species may be necessary to achieve anticipated emissions standards under the Toxics Rule. In a spray dryer absorber vessel, flue gas comes in contact with an atomized slurry of alkaline reagent and recycled solids for removal of SO₂ and acid gases. The alkaline reagent, typically lime, reacts with incoming pollutants to form calcium salts, such as calcium sulfate, calcium chloride, and calcium fluoride. Solids from the scrubber are captured in a downstream fabric filter. A portion of the reaction products and fly ash are recycled to the reagent slurry feed and the remaining are transported to landfill for disposal. The spray dryer technology, a type of dry flue gas desulfurization (dry FGD), operates at 20-30° F above saturation temperature, and as such, does not generate a wastewater purge stream as in a wet FGD, or limestone forced oxidation (LSFO) system. Spray dryers are limited in removal capabilities for higher sulfur coals compared to their wet FGD counterpart, and scrubber vessels are limited in size, generally treating up to 350 MW for a single vessel.

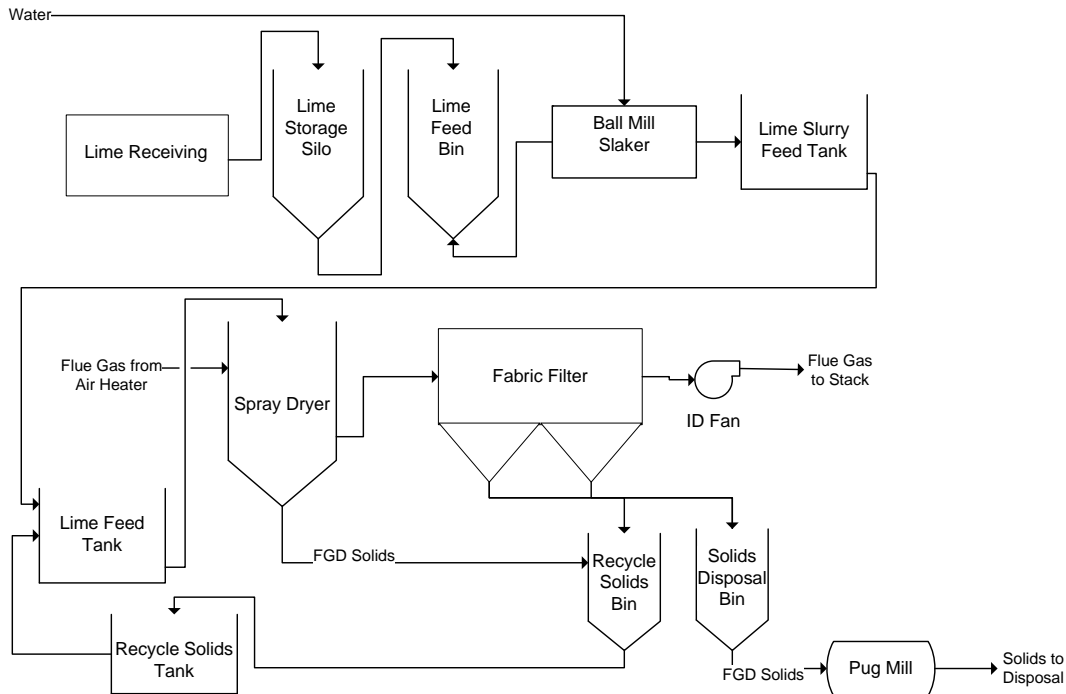
The spray dryer technology represents a mature technology that has over 30 years of operating experience, including operation at several of Exelon’s facilities. Although spray dryers have traditionally been employed for SO₂ emissions reduction from coal-fired power plants, they have also been shown to effectively remove acid gases (HCl, HF), and particulate with the downstream fabric filter, to meet anticipated MACT limits.

The lime spray dryer may be appropriate for removal of particulate, acid gases, and selenium and SO₂ at facilities that do not currently employ a scrubber system. Facilities with an existing electrostatic precipitator (ESP) or fabric filter (FF) may choose to continue operation of the existing particulate control device in order to maintain flyash sales or they may opt to abandon existing particulate control devices, relying on the spray dryer’s downstream fabric filter for particulate control, and disposing of all fly ash and FGD solid byproduct.

A general process flow diagram of the lime spray dryer is shown in Figure A-3. Major capital cost components of a lime spray dryer system include the following systems:

- Lime reagent supply and handling equipment,
- Absorber vessel and associated pumps and tanks,
- Flue gas handling systems (duct work and ID fans), and
- Waste/byproduct handling systems.

Figure A-3. Lime Spray Dryer FGD System



The spray dryer system requires a significant engineering effort and footprint at the plant site. Capital costs will be affected by the type of fuel, the desired removal efficiency, specific site arrangement and existing equipment considerations. Typical capital costs for a lime spray dryer system would likely be in the range of \$220-260/kW. Additional project costs will be incurred including engineering, construction, and general facilities that are not accounted for in the above range. Operating costs for the lime spray dryer include lime reagent, water use, maintenance, parasitic power, and solids disposal costs. Lime reagent is a major operating cost, generally on the order of \$100+/ton. Operating costs are typically around \$50-80/kW-yr, again highly dependent upon site-specific factors such as fuel type, system removal efficiency, reagent and disposal costs.

- **Technology Maturity:** mature; 30+ years operating experience
- **Number of Commercial Installations:** many
- **Expected Performance:**
 - SO₂ – 95%, dependent on fuel sulfur content
 - Acid Gases – up to 95% HCl, 45-95% HF, depending on coal properties
 - Hg – up to 90% when combined with carbon injection
- **Capital Costs:** Dependent upon unit size, site-specific factors
- **Operating Costs:** 30-50 \$/kW-yr
- **Installation Schedule:** 24-36 months from detailed design to start-up

A.2.6 Halogen Injection

In this technology, halogen-containing chemicals are injected into the furnace to supplement the coal chlorine in its effect on mercury oxidation. Halogen salts added are typically calcium bromide (CaBr_2). These salts, added with the coal or injected into the furnace, decompose at furnace temperature to form HBr/Br_2 in the flue gas. These vapor-phase halogen acids react with elemental mercury in the back pass of the furnace as the flue gas cools, to produce oxidized mercury that can be removed by a downstream wet FGD system.

Full-scale tests of furnace halogen injection have been conducted on a number of coal-fired units that fire Powder River Basin coal, Texas lignite, and North Dakota lignite. Results from these parametric tests have shown that low concentrations of bromine (20-200 ppm in the coal) can produce 50-90% oxidized mercury in the flue gas.

For example, calcium bromide injection tests were conducted at TXU's Monticello Steam Electric Station Unit 3, which is equipped with a cold-side ESP and a limestone forced oxidation scrubber. Monticello fires a 50/50 blend of PRB and Texas Lignite. Baseline mercury removal at the unit ranges from 10 to 40%. Two two-week continuous injection tests were conducted at rates equivalent to 55 ppm and 113 ppm Br in the coal. At an injection rate equivalent to 55 ppm Br in the coal, the oxidation of mercury at the FGD inlet was 67%, and the removal of mercury was 65% (computed from coal and FGD outlet gas Hg concentrations). At an injection rate equivalent to 113 ppm Br in the coal, the oxidation of mercury at the FGD inlet was 85%, and the overall removal of mercury was 86%.

Parametric and long term testing at other sites have shown that bromide addition is most effective with coals that are low in chloride (PRB) and at plants that have an SCR. The SCR, in conjunction with the bromine, act to oxidize the elemental mercury better than either individually.

The long-term effects of bromine injection on FGD chemistry and FGD or boiler materials of construction are not known. To date, the longest test durations have been sixty days, which is not long enough to evaluate corrosion effects. It is also not known if the increased concentration of bromine in the fly ash and scrubber liquor/solids will impact the reuse of these byproducts.

Capital equipment to be installed for the furnace halogen injection process is relatively simple, much like the equipment for activated carbon injection. The equipment consists of storage tanks for the halogen solution, pumps and a metering system to convey the solution to the coal, and a process control system. The capital cost of installation is estimated as \$3/kW.

The largest component of the operating cost for the process is the calcium bromide solution. This solution is currently available at ~ \$1/lb of 52 wt% solution. It should be noted that there have been several increases in the price of calcium bromide over the last two years. Today's price is more than double the 2004 price. It is unclear if such price increases should be expected in the future. The primary consumer of calcium bromide is the oil industry, which uses it as an operational fluid for offshore oil wells.

An existing patent⁸ on the use of bromine to oxidize mercury may require royalty payments to the patent holder. The amount of the royalty payment is not known at this time.

- **Technology Maturity:** Testing 5 years of experience
- **Number of Commercial Installations:** None
- **Expected Performance:**
 - Hg – An additional 10-78% above native capture, with downstream FGD system
- **Capital Costs:** 2.5-3.5 \$/kW
- **Operating Costs:** 0.25-2.5 \$/kW-yr. (Chemical cost only, no royalties)
- **Installation Schedule:** 6-12 months for design, installation, and parametric testing.
 - **Outage Required:** None.

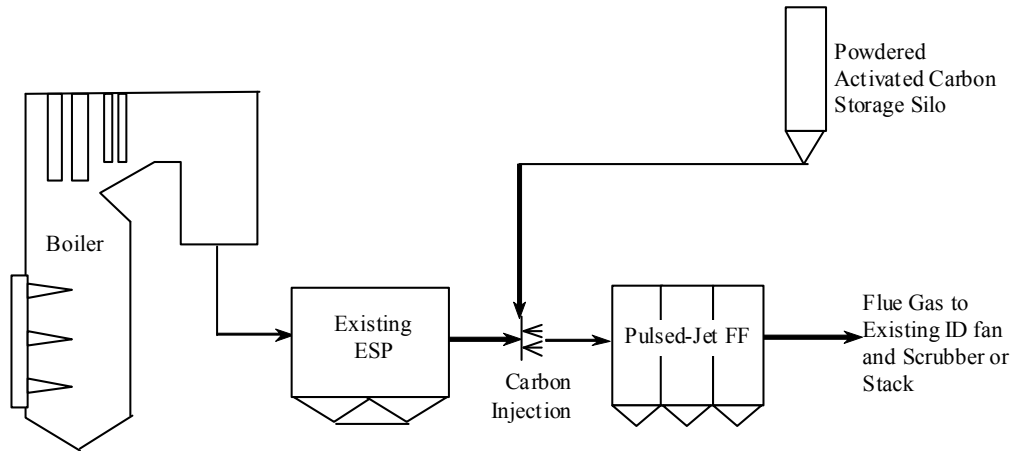
A.2.7 Toxecon

Toxecon is an EPRI developed technology that involves the injection of dry sorbent, such as powdered activated carbon into a compact pulsed-jet fabric filter installed downstream of an existing primary PM control device. The Toxecon system has been demonstrated to achieve 90%+ removal of mercury from the flue gas and offers additional reduction of PM with the installation of the baghouse. In facilities that do not currently operate an FGD scrubber, Toxecon may be coupled with alkali injection upstream of the fabric filter to achieve acid gas control, for reduction of HCl, HF, and SO₂. In general, this technology may be an attractive control option for facilities operating a hot-side ESP with no FGD system.

A generic process flow diagram of the system is shown in Figure A-4. A new pulsed-jet fabric filter is installed downstream of an existing PM control device, and a pneumatic conveying system and storage silo are included for sorbent injection. If additional alkali injection is included, a second storage silo and transport system will be required. Note that the capital cost of the DOE demonstration project at Wisconsin Energy's Presque Isle Power Plant in Michigan was \$52.9MM treating approximately 270 MWe, indicating a capital cost of over \$190/kW. However, costs for this demonstration project were likely inflated due to the nature of the demonstration/first-of-its-kind installation. Additionally, a capital cost saving configuration of Toxecon may be employed whereby the last fields of the ESP are converted to a fabric filter PM collector (Toxecon 1.5). In this case, the sorbent injection point would be just downstream of the ESP fields, and upstream of the converted fields. Elimination of the new fabric filter housing from the system configuration would be expected to reduce the capital costs by 50-60% in comparison with the full Toxecon system.

⁸ Vosteen, B. US Patent 6878358.

Figure A-4. Toxecon System



Operating costs of the Toxecon system include costs for powdered activated carbon, power associated with additional pressure drop across the fabric filter, solids disposal, and fabric filter maintenance, including bag filter replacement. Operating costs are estimated to be \$4-6/kW-yr.

- **Technology Maturity:** Commercial demonstration completed; sorbent injection and fabric filter are proven technologies.
- **Number of Installations:** ~5
- **Expected Performance:**
 - Hg – 90%+
 - Acid Gases – up to 90% HCl, HF with alkali injection
 - SO₂ – 40-70% with alkali injection
 - Se – up to 90% with alkali injection
- **Total Project Costs:** Demonstration project cost \$190/kW)
- **Operating Costs:** 4-6 \$/kW-yr.
- **Installation Schedule:** 12-24 months from detailed design to start-up
 - **Outage Rrequired:** 5-10 days.

A.2.8 Wet Flue Gas Desulfurization (FGDw)

Wet flue gas desulfurization processes remove SO₂ from coal- and oil-combustion flue gas by reacting the gas with a re-circulating alkaline reagent solution or slurry. The alkaline reagent, typically a limestone or lime slurry, reacts with the incoming SO₂ in a spray tower to form calcium salts such as calcium sulfate dihydrate (gypsum) or calcium sulfite. Solid precipitation occurs in an integrated reaction tank. The produced byproduct solids are removed from the process by way of a slurry purge routed either to a solid filtration system or to a gravity settling pond. Removal of SO₂ across a wet FGD system is determined by the size and design of the scrubber unit, the gas-liquid contact properties, and the scrubber operating parameters (i.e.,

nature of the FGD process chemistry). High efficiency FGD scrubbers are capable of removing 95 – 99% of the SO₂ present in the gas, depending on many factors associated with unit design, operating conditions, and flue gas composition. Wet FGD systems have historically been able to achieve higher SO₂ removal levels than dry FGD systems and are generally more cost effective (than dry scrubbers) for the treatment of flue gas derived from coal containing moderate to high sulfur levels (i.e., >2%).

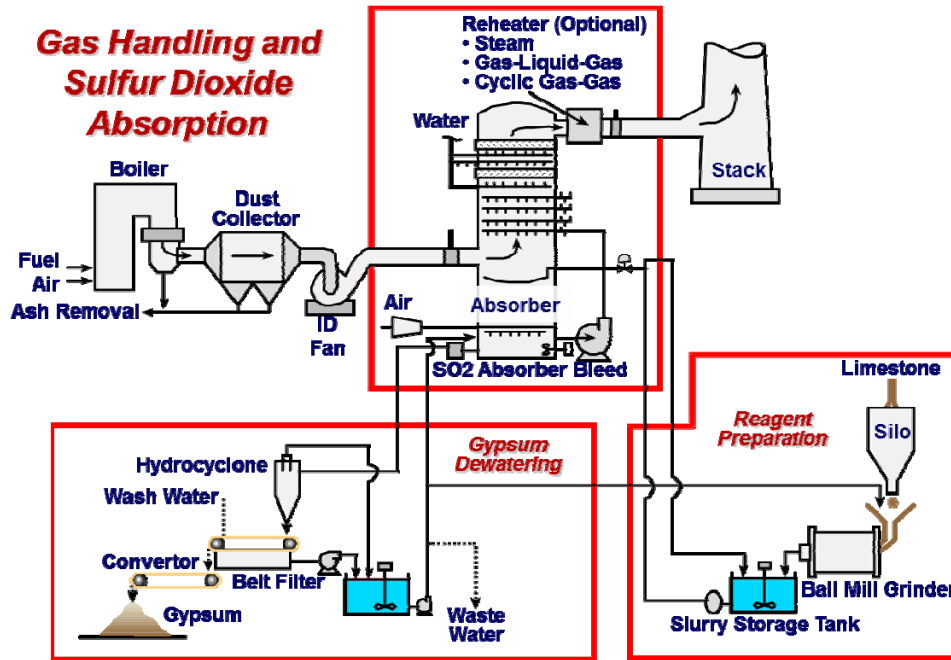
Wet FGD is a mature technology that has over 40 years of commercial operating experience in the U.S and represents greater than 80% of FGD technology installed on fossil fuel-fired power plants. The addition of wet FGD represents an appreciable cost to a utility due to high associated capital costs but the technology is technically sound and operational risks associated with the technology have decreased with continued operating experience and technology development. Although wet FGD is typically employed for SO₂ removal, it is also effective at removing acid gases, such as HCl and HF, from flue gas; wet FGD absorbers can also remove up to 50 – 70% of the particulate matter present in the gas, depending on the gas-liquid contact properties of the unit. Furthermore, evaluation of coal and process data from the EPA ICR database indicates that plants configured with wet FGD achieve high levels of selenium removal from the flue gas.

A wet FGD system may be appropriate for the removal of SO₂ and acid gases at plants that do not currently employ a scrubber system. Furthermore, the wet FGD absorber would be expected to provide additional removal (50-70%) of particulate matter penetrating the upstream electrostatic precipitator (ESP) or fabric filter (FF). Wet FGD processes are also effective at removing oxidized forms of mercury from flue gas. Thus, for bituminous coal fired plants with high flue gas mercury oxidation, particularly those employing SCR for NO_x control, high levels (70 – 90%) of mercury removal might be expected across a wet FGD system. For units firing Western sub-bituminous coal that typically produce flue gas mercury mainly in the elemental form, wet FGD provides the option for a plant to employ a mercury oxidation technology, such as boiler halogen (salt) addition, to decrease mercury emissions. For units configured with FF or Toxecon, wet FGD provides for the ability to take advantage of the natural tendency of fabric filters to oxidize mercury thus enhancing overall system removal; this effect is even greater when employing activated carbon injection upstream of the fabric filter resulting in most of the mercury that is not removed across the fabric filter getting removed across the FGD absorber.

Despite being effective at removing oxidized forms of mercury from flue gas, some wet FGD absorbers have experienced mercury re-emissions from the process. Here, mercury captured by the FGD unit is chemically reduced back to volatile elemental mercury that subsequently exits the absorber with the flue gas. Mercury re-emissions are not well understood at this time but are believed to be impacted by a number of FGD operating parameters (associated with the process chemistry). The re-emissions can be controlled using chemical additives added to the process to complex or precipitate the captured mercury.

Figure A-5 illustrates the primary components of a wet FGD process. The process can be operated under forced-, inhibited-, and natural oxidation modes. A number of reagents can be used to provide alkalinity to the process; limestone and lime represent to most common used.

Figure A-5. Illustration of Wet FGD Process; Example shows LSFO Process



For a typical limestone forced oxidation FGD process, the major cost components are associated with the following process systems:

- Flue gas handling (ductwork; bypass dampers, motive force, etc.)
- Absorber unit
- Reaction tank
- Reagent preparation
- Solids dewatering and handling
- Oxidation air
- Mist elimination
- Gas reheat (for units operating dry stacks)
- Control systems
- Wastewater treatment
- Chimney (e.g., modification from dry to wet stack)

Operating and maintenance cost categories include:

- Feed materials and chemicals
- Labor and supervision
- Waste disposal
- Maintenance, materials, and other costs
- Auxiliary power costs
- Water/water treatment costs

A wet FGD system requires a significant engineering effort and appreciable footprint at the plant site. Capital costs will be affected by the size of the boiler, type of fuel fired, required removal efficiency, solids dewatering approach, specific site arrangement, and existing equipment considerations. Capital costs for a wet FGD system can range from roughly \$300 - \$600/kW, depending on a large number of factors; additional project costs will be incurred including engineering, construction, and general facilities that are not accounted for in the above range. Fixed O&M costs can range from approximately \$9 - \$19/kW-yr, depending on the size of the unit, and variable O&M costs can range from \$15 - \$38/kW-yr. The latter is impacted by plant size and site specific factors such as delivered reagent costs, byproduct transport and disposal costs, water and wastewater costs, and auxiliary power consumption costs; these costs can be offset by revenues associated with byproduct sales.

- **Technology Maturity:** Over 40 years of commercial operation.
- **Number of Commercial Installations:** Wet FGD is installed on many plants representing roughly one-third of the coal-derived electric generation (i.e., >100 GW) in the U.S.
- **Expected Performance:**
 - SO₂: High-performance FGD scrubbers can achieve 95 – 99% SO₂ removal.
 - HCl: Most well-performing wet FGD units are able to achieve hydrogen halide removal rates equal to or greater than the respective SO₂ removal rate.
 - PM: High-efficiency FGD units can typically remove up to 50-70% of the particulate material entering the absorber in the flue gas.
 - Mercury: Wet FGD units can typically remove 85-90% of the oxidized mercury present in the incoming flue gas; elemental mercury removal is typically less than 10%. Overall mercury removal is impacted by the extent of mercury re-emissions experienced by a given absorber unit.
- **Capital Costs:**
 - \$300 - \$600/kW
- **Operating Costs:**
 - Fixed O&M costs can range from \$9 - \$19/kW-yr while variable O&M costs can range from \$15 - \$38/kW-yr.

- **Installation Schedule:**
 - Typical schedules for the design, installation, and startup of new FGDs range from 24 – 44 months.
- **Outage Required:**
 - 4 – 8 weeks.

A.2.9 Wet Electrostatic Precipitator (WESP)

Wet electrostatic precipitators (WESPs) have been used in many industries for the effective control of sulfuric acid and PM for over 100 years. However, only in the past several years has the WESP been considered practical and necessary for utility applications. WESPs have been considered and employed on the utility scale in order to reduce ultra-fine and condensable PM, including acid mist removal downstream of a wet scrubber. Although utility applications of WESP are fairly new, they have been shown to achieve high levels of SO₃ removal (> 80%) when used in combination with a wet FGD system. The collection of submicron PM is improved in the WESP over the dry ESP due to the ability of a WESP to achieve higher corona power levels, and the operation at saturation temperature, which promotes condensation of soluble acid aerosols.

A WESP is configured much like a dry ESP, using multiple collecting and electrode fields. It is designed for large gas volumes, high PM inlet loading rates, and low outlet emissions. The parallel collecting fields are arranged in series and housed in a single enclosure. Collecting plates in a WESP are specifically designed to ensure uniform water film over the entire collecting area and an integral part of the WESP design is location of water spray nozzles to allow sufficient coverage over the collector plates. WESPs generally employ special alloys in order to avoid corrosion. One vendor has touted their membrane WESP as offering 20-30% cost savings over the conventional WESP by replacing solid sheet/tube collecting electrodes with fabric membranes that disperse water through capillary action. The membrane WESP has seen installation on non-utility applications up to approximately 185 MWe.

A WESP incurs higher capital costs than its dry counterpart, mainly due to the materials of construction required in order to avoid corrosion problems. Because the cost of the system is highly dependent on incoming flue gas and wash water content, which will vary from site-to-site, capital costs may fall in range of \$75- 200/kW, depending upon unit size. As stated above, the commercial membrane WESP may potentially offer 20-30% cost savings over its traditional counterpart.

Operational costs of the WESP include pressure drop typically associated with a PM collector, energizing of the collector plates, as well as water consumption and water discharge. There are also potential water treatment costs; however they are not included in the costs presented here. In many cases the wastewater is sent to the FGD reaction tank.

- **Technology Maturity:** mature; 100+ years of operating experience on industrial applications;
- **Number of Commercial Installations:** several at the utility-scale;



- **Expected Performance:**
 - PM – 99%+
 - HCl – not quantified; 90% expected
 - Hg – potentially 95% with wet scrubber
- **Capital Costs:** \$75-200/kW, dependent upon unit size and configuration
- **Operating Costs:** \$3-4/kW-yr.
- **Installation Schedule:** 12-24 months from detailed design to start-up
 - **Outage Required:** 5-10 days.