**APPENDIX 1**
**EXAMPLES OF HARM RESULTING FROM FAILURE TO STAY THE BOILER AND CISWI RULES**

## I. HARM TO ECONOMIC SECTORS

### 1. Sugar Production

There Will Be Inadequate Time to Comply With the Boiler Rule After the Reconsideration Proceeding is Finished.

As detailed below, it will take a full three years to achieve compliance with the Boiler rule. If the rule is not stayed pending reconsideration, companies will not have time to comply because the reconsideration process will take months, and perhaps as much as one year, of the necessary three-year compliance period for existing boilers.

Due to the significant equipment purchases necessary to comply with the final rule, sugarcane processing companies must start the planning, engineering, and permitting process immediately. Capital costs must be determined and funding requests approved. Immediate expenditures will need to be made for the following activities:

- Initial testing of existing boilers to determine current emission levels. This will require long-term testing with PM and CO Continuous Emission Monitoring Systems (CEMS) (because historical PM and/or CO compliance tests do not provide adequate data) and short-term testing for dioxin/furan (D/F).

- Preliminary identification of necessary boiler replacements, boiler modifications and add-on control equipment to meet standards.

- Obtaining vendor quotes for alternatives—i.e., new boilers, various boiler modifications, add-on control equipment, and combinations of these alternatives.

- Permitting. This process must be started immediately because it could take up to 18 months to obtain the necessary permits, depending on the state. However, in order to begin the permitting process, the specific changes to the boilers and/or add-on equipment must be fairly well known. Applications cannot be prepared until the testing and engineering work have been completed.

Expenditures necessary during the near term (within 1 year) include:

- Completing permitting activities

- Performing final engineering

- Making final equipment purchases

Expenditures necessary during the far-term (2 to 3 years) include:

- Construction to implement new boilers and/or boiler changes and/or add-on control devices

- Integrating new equipment with existing mill equipment to avoid disruptions in operations

Demand for the skilled personnel needed to provide this work will likely far exceed the available personnel, because the owners of thousands of boilers across the country will be performing the same work during the same time frame. Moreover, EPA plans to promulgate the Utility MACT before the end of 2011, which will put substantial additional demands on the skilled workforce.

The sugarcane industry cannot – and should not have to – start the compliance process until the requirements of the final rule are known. Otherwise, money and resources may be wasted to comply with a rule that could change significantly.

The Final Rule Will Be Inordinately Costly, Which Will Threaten the Viability of Individual Mills and, Perhaps, the Entire Domestic Sugarcane Industry.

The sugarcane processing industry in Florida, Texas, and Hawaii began over 100 years ago. The industry's boilers all burn bagasse, which is a co-product of the sugarcane processing operation. In the 1980s, there were seven mills and 30 bagasse boilers operating in the industry in Florida and a similar number in Hawaii. Currently, only four mills and 15 bagasse boilers are operating in Florida; one mill and five bagasse boilers in Texas; and one mill and three bagasse boilers in Hawaii. The mill closings and consolidations were the result of economic conditions that dictated these changes for the survival of the industry. The sugarcane industry believes that the Boiler rule promulgated by EPA may have similar or even worse consequences, based on the following:

At most, only seven of the 23 boilers in the industry can meet the CO emission limit:

- Reductions from 54 percent to 97 percent are necessary on 16 boilers.

- Traditional methods of reducing CO (i.e., improved overfire air) will not be adequate for all of these 16 boilers; as many as 10 boilers will have to be completely replaced.

Only three boilers in the industry can meet the PM limit:

- Reductions from 86 percent to 92 percent are necessary on 20 boilers.

- To meet the new PM limits, it appears that all boilers will need to have electrostatic precipitators (ESPs).

- The requirement for a PM CEMS adds additional stringency to the PM limit and additional uncertainty concerning the boilers' ability to meet the PM limit, because there are no operating PM CEMS on any bagasse boilers.

Only a few boilers have $O_2$ continuous emission monitoring system (CEMS) as a surrogate for CO, and none have PM CEMS:

- $O_2$ CEMS are required for 21 boilers.
- PM CEMS are required for 23 boilers.

The total cost of compliance will be extremely high for each mill because of the large number of boilers:

- Three mills each have five existing boilers; one mill has six boilers; and two have three boilers.
- Cost of ESP to meet PM limits: ~ $4 million to $7 million capital cost per boiler.
- An advanced technology, such as a CO oxidation catalyst, will likely be needed to meet the CO limit, if combustion modifications cannot achieve the limit: ~ $5 million minimum capital cost per boiler (assuming this technology is feasible on a bagasse boiler).
- Cost to replace a boiler with necessary controls: ~$30 million to $50 million.
- Average cost per boiler: ~ $10 million to $15 million.
- Total cost to sugarcane processing industry: ~ $250 million to $350 million.

Most other large industrial sources have only one or two boilers subject to the Boiler rule. In contrast, three individual sugar mills will each have five or six boilers subject to the rule; one mill will have four boilers; and one mill will have three boilers.

In the worst case, a mill may have to shut down due to economic impacts.

Jobs directly associated with the sugarcane industry include those provided at the sugar mills, those provided in the agricultural operations, and administrative personnel. In Florida, the total direct employment in the sugar industry is approximately 5,000 persons; in Texas, it is 1,000 persons; and in Hawaii, it is 800 persons. Indirect employment (contractors, vendors, consultants, etc.) is many times these numbers.

The worst-case impact of the Boiler rule is the complete shutdown of the sugarcane industry in the U.S and the moving of it overseas. In this case, the total U.S. employment loss would be approximately 6,800 persons. A less conservative estimate would be the closing of several mills and further consolidation of the industry. Consolidation would likely cut approximately 2,000 employees in Florida and 500 in Texas from current payrolls.

All of the mills are located in or near small agricultural-based towns. These towns depend on these sugar mills for their local economy; these towns, such as the "Glades"

areas of South Florida, would be devastated by the loss of jobs and mill closings that would result if the Boiler rule is implemented in its current form.

The New Source Standards Are Unattainable For Bagasse Boilers.

The emission limits for new sources in the hybrid suspension/grate boiler subcategory are as follows:

- Total PM standard of 0.0011 lb/mmBtu heat input
- HCl limit of 0.0022 lb/mmBtu
- Hg limit of $3.5x10^{-6}$ lb/mmBtu
- CO limit of 1,500 ppmvd @ 3% $O_2$
- D/F limit of 0.20 ng/dscm TEQ @ 7% $O_2$

The impact of the Boiler rule on the design, operation, and viability of new boilers is significant. There is grave concern that these standards are unattainable. The PM standard for new boilers is 35 times more stringent than the existing source standard. There are no bagasse boilers that are achieving the PM limit in the Boiler rule for new sources. There is no known technology that can reduce PM emissions on a bagasse boiler to the level required by the Boiler rule for new sources. The sugarcane industry is not aware of any boiler manufacturer or air pollution control equipment manufacturer that will guarantee such a low emission rate on a bagasse-fired boiler.

**2. Chemical Production**

Dioxin/Furan Emission Standards and Related Requirements

If not stayed, these rules will present irreparable harm to chemical production facilities with existing coal-fired boilers due to the ultra-low emission standards and significant engineering uncertainty in how to achieve the standards by the compliance deadline.

EPA has stated that it may reconsider the dioxin standards and testing requirements; numerous industry petitions for reconsideration will be strongly supportive of EPA's reconsideration of these provisions. However, if EPA undertakes reconsideration of these provisions, affected companies will not know for a year or more what EPA's final requirements will be. If these provisions are not stayed during the period of reconsideration, existing sources will lose at least one year of a three-year compliance time-frame and will be significantly harmed in rushing to comply with final requirements in the remaining compliance time frame.

The D/F emission limits are fundamentally flawed and unachievable, as will be discussed in significant detail in soon-to-be-filed petitions for reconsideration. In order to comply with D/F standards, one must first understand the stack chemistry that affects D/F

formation and how to control D/F emissions. There is a general lack of knowledge in the scientific and engineering community on dioxin/furan formation.

In order for a source to try and come into compliance with these emission limits, the source is going to have to undertake extensive performance testing and analysis to better gauge how to operate each affected unit to achieve compliance. Each performance test costs between $10,000 and $20,000 per unit, and many companies have multiple units to test.

Example 1: A chemical manufacturing company facility has three pulverized coal fired boilers that are equipped with a baghouse and two electrostatic precipitators (ESPs). The facility has estimated that the potential cost of installing additional controls on these boilers ($35 million) to try and meet D/F emission limits and other HAP limits exceeds the capital costs of operating this facility, making these expenditures economically infeasible. The company believes it has limited options: one option is to offset the costs of additional controls by reducing operations and jobs, but the company believes it would be irresponsible to take that approach without an assurance that an investment of $35 million in control technology would achieve the final emission limitations. The company is not aware of any available control technology for these three boilers that would be capable of meeting the D/F emission limits. Another option is for the company to switch to modified gas-fired boilers. The estimated capital costs of this option are $20 million to $35 million, with an increase in annual operating costs and a loss in its competitive advantage in being able to offset costs through the use of readily and easily available coal. Again, an expenditure of this magnitude would be hard to justify in today's globally competitive environment and likely would result in reduced operations and jobs at the facility.

Example 2: One chemical company has a manufacturing plant for a major business line in the United States that currently employs approximately 500 workers. The facility relies heavily on eastern bituminous coal for its energy and is competitive globally primarily because of the relatively low local cost of this raw material. Because of the uncertainty in how to meet the D/F and other emission standards, this company is evaluating whether to switch to natural gas. In order to do so, significant resources would have to be expended almost immediately, e.g., the company would need to secure permits for a pipeline corridor to transmit natural gas to the plant through a newly constructed pipeline. This not only takes significant capital, but significant time to secure permits and construct the new pipeline. This company recently announced the closure of one of its overseas facilities, which will result in the loss of approximately 500 jobs in a community where the facility has operated for almost 100 years. A leading factor influencing the decision to cease this operation was the high fuel costs associated with the combustion of natural gas.

Example 3: A chemical manufacturing facility operates a fleet of 17 coal- and natural gas-fired boilers and 19 turbine generators to provide steam and electricity to support manufacturing processes. The complexity of managing such a large

integrated fleet of boilers requires careful planning to execute large capital retrofits (e.g. boiler pollution control equipment) without disrupting manufacturing operations. Six of the coal-fired boilers at the facility will be subject to Boiler MACT and an additional four coal-fired boilers will be subject either to Boiler MACT or CISWI (depending on the viability of compliance with CISWI versus other options to manage non-hazardous solid wastes). The facility has initiated an engineering assessment with a large engineering firm specializing in power generation projects, to evaluate the range of options available to comply with the final rules. To date, the facility has spent approximately $263,000 on the engineering assessment and anticipates additional invoices of approximately $55,000.

The facility already has a large (greater than $200 million) capital project underway to upgrade controls on five of its coal-fired boilers which will reduce sulfur dioxide, hydrogen chloride, and mercury emissions. This project will replace existing electrostatic precipitators (ESPs) with fabric filters and install spray dryer absorbers upstream of the new fabric filters. Two additional coal-fired boilers are equipped with spray dryer absorbers and either an efficient ESP or fabric filter and are expected to meet the particulate matter and hydrogen chloride emission limits with no further controls required. Three coal–fired boilers are expected to meet the particulate matter, hydrogen chloride, and mercury emissions by utilizing the emissions averaging provisions in the Boiler rule. This is a cost-effective solution for the facility given the facility's commitment to spend over $200 million to over-control the five boilers as mentioned above.

However, the facility's compliance strategy is now complicated by the issuance of the final rules (Boiler MACT and CISWI). Three issues have been identified which cast uncertainty and cause timing issues for the facility:

(1) The dioxin/furan emission limits set in the Boiler MACT for pulverized coal and stoker boilers are so low that the facility does not have any basis to determine a successful compliance strategy. The facility has identified flaws in EPA's methodology in setting these standards such that it believes the standards should be increased significantly or replaced with work practice standards.

(2) One boiler will have difficulty meeting the carbon monoxide standard for pulverized coal boilers. EPA denied the facility's request in comments to establish an alternative total hydrocarbon limit (in lieu of carbon monoxide) that the facility believes the boiler can achieve. The facility believes EPA's denial of its request is arbitrary and capricious. EPA states that it does not support THC as a surrogate for non-dioxin HAPs, yet logic would hold THC is a direct measure of organic HAPs whereas CO is merely an indicator of combustion efficiency. EPA made this statement even though other rules provide this alternative.

(3) The hydrogen chloride, mercury, cadmium, and lead emission standards set in CISWI for coal-fired energy recovery units are based on biomass boilers and are inappropriate for coal-fired boilers. EPA ignored comments to subcategorize these different types and classes (biomass and coal) for these pollutants. The facility believes these standards should be reconsidered and revised.

First, regarding D/Fs, the company has very little data showing how its units stand with respect to the standards. What little data exist (only one stack test each on one pulverized coal boiler and one stoker boiler), suggest that none of the 10 coal-fired boilers subject to the rule can comply with the standard without the addition of controls specifically targeted for D/Fs. The analytical laboratory flagged each of the data for D/F congeners detected with a "J" flag, indicating that the values are below the lab's reporting limit (below the lowest point on the calibration curves). This indicates to the facility that the test data have a high degree of uncertainty. The facility has no idea as to the repeatability of these tests. Outside engineering experts the facility has contacted are at a loss to recommend known compliance strategies for D/Fs. Activated carbon injection has been employed on municipal waste incinerators. However, one supplier of activated carbon systems admits it has no experience with coal-fired boilers and does not know how the technology would perform or cost when applied to coal-fired boilers, which have orders-of-magnitude-lower levels of D/Fs in their exhaust gas than municipal waste incinerators. Other experts have theorized that changing combustion conditions to increase flame zone temperatures and eliminate cold spots may reduce D/Fs, although it was noted that the effectiveness of such techniques may be limited by the geometry of the boiler's furnace. However, the facility has no data on its specific boilers to help it determine if this is true. Even if it had such data, since seven of the boilers have low-NOx firing systems with overfire air to reduce NOx, the facility would have to compensate with post-combustion NOx control such as non-selective catalytic reduction (SNCR).

As a possible worst-case scenario, the facility has obtained engineering estimates that it would cost a total of approximately $90 million for it to install activated carbon injection systems on the 10 boilers and to add fabric filters to the four boilers that don't already have fabric filters or already have a project underway to install fabric filters.

However, as stated above, the facility has no basis upon which to demonstrate which, if any, technology is appropriate to reduce D/F emissions. Because the available data are so limited, the company has sought bids to characterize the emissions profiles of additional affected boilers during the summer of 2011. An initial quote was received for around $90,000, but the company believes the quote is unrealistically low due to the significant expansion in the scope of necessary testing.

Second, regarding the lack of a total hydrocarbon (THC) alternative to avoid CO controls at one of the facility's boilers, the facility has retained an engineering

firm to assess it's MACT compliance alternatives. The firm identified several technological barriers that ruled out the use of a catalyzed oxidation (CatOx) system to control CO emissions, and instead recommended that a Computational Fluid Dynamics (CFD) model be developed to assess the specific combustion issues that were causing the high and variable CO emissions. The facility adopted this recommendation and has since issued a purchase order for around $160,000 to a modeling firm to conduct the testing and modeling required to identify how to control the unit's CO emissions. As stated above, combustion changes could cause the facility to install SNCR to meet its NOx limit. While the facility has obtained no specific engineering cost estimates for this technology, it is expected to cost between $5 million and $10 million.

Third, regarding CISWI, the facility has estimated it would cost an additional $10 million to comply with the final CISWI rule, assuming neither Boiler MACT nor CISWI is revised. If Boiler MACT were to be stayed and revised as the facility believes it should be, and CISWI is not revised, the facility would be facing a $50 million capital expenditure. However, as stated above, the facility believes EPA should reconsider the standards applicable to coal-fired boilers. If EPA does so, the facility believes much of this expenditure will not be necessary.

Summary: Without an immediate (before July 1, 2011) stay of both the Boiler and CISWI rules, the facility must begin to spend the money described herein. Initially (during 2011), this will be $100,000 - $200,000 in stack testing plus $160,000 to perform engineering work related to CO control. Later in the year, detailed engineering work on capital projects to execute whatever control strategies are selected to meet the final rule's D/F standards would begin and are expected to cost between $1 million and $3 million. Without a stay by the end of 2011, the facility would continue to spend money on the capital projects at a more accelerated pace to finalize engineering, begin to order equipment, and complete on-site construction. Up to an estimated total of $90 million would be spent on the Boiler rule to comply with the D/F and CO standards. If the facility elects to comply with CISWI, an additional $3 million would be spent.

Without resolution of the three issues described herein, the facility is constrained in determining its best compliance strategies. The facility believes there are flaws in the final rules which must be corrected. Without a timely stay to the rules, the facility will continue to spend money that cannot be recovered, to comply with what it believes are flawed and unlawful standards.

Natural Gas Curtailment

EPA must stay the application of the Boiler MACT regulations during the process of reconsidering such regulations to prevent irreparable harm to industry. If the regulations are not stayed during the reconsideration process, companies may needlessly spend a significant amount of time and money to contract for a service level (non-interruptible vs.

interruptible) that would reduce, but not eliminate, the probability of curtailment, or be forced to accept significant prices increases in their natural gas contracts that would apply for periods of curtailed natural gas supply.

The current definition of "Period of natural gas curtailment or supply interruption" in the final [40 CFR 63.7575] means *"a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption."*

During curtailment periods as classified by the applicable natural gas supply company, natural gas users typically receive a curtailment notice 48 hours in advance, and such curtailment would effectively be imposed for reasons beyond the control of the facility. During such curtailment periods, natural gas deliveries typically may be reduced to a certain percentage of the normal flow rate, or supply above a certain percentage of typical demand may be priced at much higher level than prices under non-curtailment conditions. The application of the price surcharge typically does not apply to 100% of typical demand. In the past, only on vary rare occasions and under very specific circumstances has a natural gas provider been forced to impose a 100% reduction in natural gas supply, e.g., pipeline ruptures or scheduled maintenance where the line is taken out of service.

Many facilities operate using natural gas as their primary source of energy. All such facilities have natural gas contracts that define actions and associated costs for services provided by the applicable natural gas supplier. These natural gas contracts define rates and associated costs for periods of normal gas supply and for periods of natural gas curtailment. During periods of natural gas curtailment, the rates charged are much higher (as much as 3 times higher) than during periods of normal flow rates. Since the current rule prohibits the combustion of an alternate fuel during these curtailment periods, should EPA decide not to stay the application of the Boiler MACT regulations while such regulations are being reconsidered, companies would be forced to pay excessive prices for natural gas during curtailment periods.

If companies are prevented from accommodating the combustion of an alternate fuel during curtailment, they would be irreparably harmed by less favorable rates during normal supply periods in exchange for more reasonable rates during curtailment periods.

## 3. Iron and Steel Production

The Boiler rule is an impediment to investment in certain new energy recovery projects in the iron and steel industry, resulting in both immediate economic harm and lost environmental benefits. Integrated iron and steel manufacturers are energy intensive industries that utilize process gases extensively to offset fossil fuel consumption. Approximately 5% of the process gases generated in this industry (blast furnace gas

(BFG), coke oven gas (COG), etc.) are still being flared. The U.S. Department of Energy has recognized the many benefits of harvesting these flared gases by awarding grants to help fund projects that install boilers that use otherwise flared process gases to generate steam and electricity. Unfortunately, the Boiler MACT major source rule has created an obstacle to the installation of new boilers that burn process gas.

For instance, a project has been proposed by an AISI member to replace natural gas-fired boilers with coke oven gas-fired boilers that would generate both steam and electricity for the facility. In phase one, the project could immediately save the company several million dollars per year by reducing annual natural gas usage by 700 million cubic feet. In phase two, the project would add steam turbine generators to produce electricity from the steam generated. This energy improvement project is a critical part of a cost reduction strategy necessary for the facility to remain globally competitive, which is critical to preserving, in this instance, over 200 U.S. jobs. The project will also remove over 100,000 tons of Greenhouse Gas (GHG) emissions per year and many tons of other criteria pollutants by reducing the amount of fossil fuel this facility needs to burn.

Without relief, the Boiler MACT rule will kill this energy improvement project and send process gases back to flares throughout the industry. The new boilers, if installed, would be immediately subject to the new source Boiler MACT emission limits for "Units Designed to Burn Gas-2 (Other) Gases." *See* Table 1 to Subpart DDDDD. EPA set each emission limit based on the rate achieved by the best performing single source burning any of the gaseous fuels that EPA has deemed "Gas-2." The additional cost for new COG-fired boilers equipped with the controls that EPA identifies for meeting these numeric Gas-2 emission limits is estimated at over $7 million in capital cost with an annualized cost, including operation, maintenance and monitoring costs, of over $3 million per year. Vendors have been unwilling to guarantee that their recommended control devices can achieve these limits consistently. By contrast, the existing boilers burning natural gas face no control costs. Boiler MACT assigns natural gas-fired units a work practice, instead of numeric emission limits, that requires a periodic tune-up to ensure efficient fuel combustion. Boiler MACT makes moving flared coke oven gas to a boiler more expensive than buying natural gas for the boiler and flaring the process gas. Even if the cost of natural gas increases significantly in the future, this source has no guarantee that the control equipment investment necessary to burn coke oven gas will consistently achieve the Boiler MACT limits.

The harm associated with killing this project is not just economic; there is immediate environmental harm as well. Moving flared gas to an existing boiler or furnace improves the environment in three ways:

1. The COG displaces the natural gas that is currently fueling the boilers, which reduces tens of thousands of tons of NOx, Greenhouse Gases, and other emissions associated with natural gas combustion. Since the COG is already burned at a flare, moving it to the boiler does not add any new emissions.

2. In fact, moving the flared COG to an enclosed boiler significantly improves organic compound destruction efficiency. EPA's compilation of emission factors

(AP-42) assigns flares a 98% control efficiency for the destruction of organic compounds. By contrast, EPA considers boilers 99.9% efficient at combusting organic compounds, suggesting that this COG-fired boiler project will significantly reduce organic compound emissions.

3. Finally, generating electricity with this process gas also reduces offsite fossil fuel consumption by reducing the demand for purchased electricity. The majority of baseload electricity is generated with coal, which means this project would also reduce the SO2, NOx, PM, Hg, and GHG emissions associated with the fuel that would otherwise be burned to generate the electricity no longer needed due to the phase two electricity generation proposed for this project.

In partial response to presentation of this issue during the comment period, EPA added new clean fuel specifications to the final rule. These fuel specifications were not in the proposed rule. As such, industry did not have a chance to comment on these specifications and how they might be adjusted to provide relief for COG-fired boilers. EPA's "Notice of Reconsideration of Final Rules," 76 Fed. Reg. 15,266 (March 21, 2011) acknowledges that establishing the fuel specification is one of the issues "for which we believe reconsideration and additional opportunity for public review and comment should be obtained." A stay of the Boiler MACT rule until the reconsideration issue is resolved would help preserve the viability of the project while EPA considers comments on the fuel specification and other related provisions.

**4. Municipal Solid Fuel-Fired Utility Boilers**

Municipal utilities, and many other small public entities, will experience significant and immediate harm if the Boiler rule is not stayed pending the outcome of the reconsideration process. The final Boiler rule requires that existing sources comply with the final emission standards within three years after the date the final rule was promulgated. Municipal utilities will need every minute of this time period and more to comply with the Boiler MACT rule.

EPA has indicated it will reconsider a number of issues relevant to the compliance obligations and options available for municipal utilities and other public entities. Additional public comment and Agency evaluation is expected to result in changes to the final rule. This uncertainty leaves municipal utilities in an untenable situation - move forward and risk wasting limited municipal resources planning for a rule that will change after reconsideration; or wait for final decisions on reconsideration and miss compliance deadlines. Municipal utilities need a stay of the rule until the Agency completes the reconsideration process. This will help ensure that scarce municipal dollars are not wasted.

To illustrate the dilemma faced by municipal utilities, one municipal utility developed the following detailed schedule for complying with the Boiler MACT rule. As indicated by the schedule, municipal decisions move more slowly than private sector decisions. Each significant issue requires consideration by the Utility Committee that recommends a solution to the Utility Board that, in turn, recommends a solution to City Council. The

City Council procedure ensures that Council Members have time with experts on the project to answer the elected officials' questions. The Council is required to convene multiple public meetings with notice and opportunities for public input before making each significant final decision required for the project. The attached schedule anticipates this City Council approval process for three decisions in the first 15 months: (1) preliminary project design, (2) 2012 cost appropriations, and (3) the project financing. The schedule does not include time for significant objections, adverse public reactions to new rates, or other obstacles that may arise in any political decision-making process. These decisions must proceed sequentially, because the project financing cannot be considered until the project design is approved. Similarly, the project manufacturing and installation must occur after the project engineering has defined the equipment or process changes in sufficient detail, to allow determinations on what permits must be secured prior to project construction.

Once the project has been approved, the schedule must allow time for the unique public process for bidding procedures and contract requirements required by statute. The schedule below includes the time necessary to comply with Ohio Revised Code Chapter 155, which sets forth the specific bid procedures and contract requirements for municipal utilities in Ohio. Once a significant project expenditure is approved by Council, it must then be advertised in a newspaper of general circulation for two to four weeks, the bids must be publicly opened, and a contract entered (or rejected) within 60 days with the lowest and best bidder. The attached schedule does not include potential delays arising from the rushed preparation of bid documents or if the bids received exceed acceptable project costs.

| **Date** | **Time** | **Description of Project Milestone** |
|---|---|---|
| **March 21, 2011** | | **MACT Rule published in the *Federal Register*** |
| Mar.-May 2011 | 12 wks | Preliminary engineering feasibility study |
| May 2011 | | Submit 2012 Budget (continues preliminary feasibility costs for 2012) |
| May-June 2011 | | Utility Board committee meetings to consider study and recommend to full Utility Board for consideration |
| June-July 2011 | 2-4 wks | Utility Board & City Council workshops on preliminary study |
| Sept.-Oct. 2011 | | Utility Board approves preliminary concept and identifies information needed for final project consideration |
| Oct. 2011 | | Utility Board receives final preliminary engineering report and approves project with recommendation to City Council |

| Date | Time | Description of Project Milestone |
|---|---|---|
| Nov. 2011 | 2 wks | Project Design - City Council 1st reading (notice agenda prior to meeting) |
| Dec. 2011 | 4 wks | Project Design - Utility Board, City Council, & public workshops |
| Jan. 2012 | 2 wks | Project Design - City Council 2nd reading (notice agenda prior to meeting) |
| Feb. 2012 | 2 wks | Project Design - City Council 3rd reading (notice agenda prior to meeting) |
| Mar. 2012 | 30 days | 30-day waiting period for proceeding with project after City Council approval |
| Mar. 2012 | | Final appropriation process for 2012 project costs |
| Apr.-June 2012 | 12 wks | Conduct rate study in support of project financing and feasibility analysis |
| May 2012 | | Submit 2013 Budget (with projected 2013 project costs) |
| July-Sept. 2012 | | Appropriation Amendment to fund 2012 project costs: City Council meetings (1st reading, public workshops, 2nd reading, and 3rd reading) [Excludes August when Council is not in session] |
| Oct. 2012-Jan. 2013 | 12-16 wks | Financing option discussions with Utility Board with bond rating process as necessary to determine credit worthiness for bond financing of project |
| Feb. 2013 | | Utility Board consideration and approval of project financing recommendation to City Council |
| Feb.-Mar. 2013 | | Financing - City Council 1st reading, public workshops, 2nd reading, 3rd reading |
| Mar. 2013 | | Final appropriation process for 2013 project costs |
| Apr. 2013 | | 30-day waiting period for City Council's financing approval |
| May 2013 | | Budget for 2014 project costs |
| May-Oct. 2013 | 24 wks | Project engineering |
| Oct. 2013-Mar. | | Air permitting evaluation, prepare and submit application (if |

| Date | Time | Description of Project Milestone |
|---|---|---|
| 2014 | | needed), procure final permit as needed |
| Mar. 2014 | | Final appropriation process for 2014 project costs |
| Apr.-Aug. 2014 | 20 wks | Bid out major equipment and award contracts; prepare bid documents, publish bid request; collect and evaluate bids; approve winning bid |
| Sept. 2014-Aug. 2015 (or May 2016) | 12-22 mos. | Manufacture of equipment and preparation of installation plans and specs; install and startup |
| **May 20, 2014** | | **MACT Rule compliance** |
| **May 20, 2015** | | **MACT Rule compliance - with 1-year extension for installation of controls (discretionary)** |
| **May 20, 2016** | | **MACT Rule compliance – with additional extension pursuant to Presidential Exemption (CAA 112(i)(4)) (discretionary)** |

This Boiler MACT implementation schedule is conservative. It assumes an orderly process without upsets or delays. It assumes that contractors will be available to engineer, manufacture, and install this equipment within the timeframes allotted, which may not be the case given the demand on these resources from this and other rules mandating additional emission controls on combustion units. It also does not account for the extended public process (five regularly scheduled City Council meetings) required by City Charter to accommodate objections to rate increases recommended by the Utility Board. Even under this conservative schedule, however, this municipal utility will need two discretionary extensions under Clean Air Act Section 112(i) to give the City any chance of meeting the Boiler MACT compliance deadline.

EPA has indicated that it will engage in reconsidering the Boiler MACT rule to allow public review and comment on a number of key issues that were not adequately presented in the notice of proposed rulemaking. For instance, EPA has stated that it will grant reconsideration for the limited use major source boiler subcategory, which offers compliance options for municipal utility boilers that must keep backup capacity available on demand to support a reliable electricity supply grid. If, after reconsideration, EPA decides to treat these limited use units differently, the scope of the Boiler MACT compliance project will change significantly. Similarly, EPA has indicated that it will grant reconsideration on the proposed subcategories in the final rule designed to encourage fuel switching from coal to biomass or other fuels. If those subcategories change after reconsideration, municipal utility compliance options will change as well. Small municipalities cannot afford to waste tens of thousands of dollars on preliminary

engineering costs chasing a rule that EPA will be reconsidering over the course of the next several months. EPA should not push municipalities to make hard decisions on allocating limited resources until the Agency completes the Boiler MACT rule, including the reconsideration process. An administrative stay until the end of reconsideration is necessary to avert significant harm for municipal utilities.

**5. Operators of Coke Oven Gas-Fired Boilers**

Producers of metallurgical coke in byproduct coke plants, both independent producers and integrated steel producers with cokemaking capacity, recover coke oven gas that is used as a fuel for boilers and other heating requirements within those establishments. Coke oven gas has approximately half of the heating value of natural gas, and its use conserves natural gas or other fuels for which it substitutes. Moreover, if coke oven gas cannot be used for these purposes, it must be flared and the environment is adversely impacted. Coke oven gas is not unlike blast furnace gas or waste heat, both of which are exempted under the rule, in terms of how it is a process gas recovered and utilized as a fuel in the iron and steelmaking process, with attendant benefits of energy efficiency and environmental benefits.

The final Boiler MACT Rule is not clear as to how coke oven gas-fired boilers or process heaters are to be regulated. By various interpretations of the provisions of the rule, these units may be considered to be exempt altogether under the definition of waste heat, exempt by virtue of coverage under other coke-related MACT rules, subject to Gas 1 requirements, or subject to Gas 2 requirements. The potential harm to the industry is highly variable depending on these interpretations, and cannot be accurately determined without clarifications of the rule through a reconsideration process.

As stated in the industry's comments on the proposed rule, in the worst case interpretation - applicability of Gas 2 requirements - the emission limits could not be met, even with estimated industry-wide annualized cost for all boilers firing coke oven gas of approximately $600 million or more for emission control equipment. In that case, to ensure compliance, companies would likely opt to replace the coke oven gas with natural gas at an estimated cost of approximately $300 million per year. However, until questions of applicability are resolved, companies will need to consider parallel paths of testing, engineering, design, procurement, construction, and compliance demonstrations to be in position to make the necessary business decisions. A stay of the rule will allow time to provide sufficient resolution of these uncertainties and avoid needless costs that would be necessary to pursue alternative regulatory compliance paths.

**6. Biomass Power Producers**

The Boiler rule as proposed would affect 200,000 boilers nationwide and would result in an undue burden on the biomass power industry. Coupled with the CISWI and NHSM rules, the Boiler rule could result in the closure of certain wood-fired and other biomass power plants. The perverse impact of this final rule would result in lost fuel sources

making their way into landfills, the loss of jobs and local economies resulting from the closure of existing, viable facilities, and the loss of renewable energy resources and their environmental benefits.

For instance, in Michigan alone, the wood-fired power industry provides $68 million annually for local, mostly rural economies and supports 1200 well-paying jobs. The power they generate – approximately 1 million megawatt hours annually – would have to be replaced by other energy sources, in all likelihood fossil fuels such as coal and natural gas. Were it not for these facilities, forest residues would be left on forest floors, creating significantly more Greenhouse Gas emissions and inhibiting maintenance of healthy forests. In addition, "urban wood," such as clean construction waste and broken crates and pallets would end up in landfills, where they would generate additional Greenhouse Gases and result in the need for more and bigger landfills.

For new and existing major sources, the Boiler MACT establishes numeric emissions limits for five pollutants, including carbon monoxide and dioxins/furans. However, the regulatory uncertainty surrounding these limits would inevitably force certain fuel types to stop being used. For instance, compliance with the dioxin/furan limit is uncertain for many facilities. One small facility would be forced to spend $50,000 just to test for current levels of these substances and determine if compliance would even be feasible for the rules as promulgated. The practical impact of this cost would essentially be that plants like this would have no choice but to drop fuels that EPA would now consider a solid waste. In another instance, compliance with carbon monoxide emission limits could force certain plants to close when those plants are required to comply with overlapping NOx limits.

EPA's rules would, therefore, result in fewer biomass fuels being converted into natural, sustainable energy. Implementation of these rules would cause the U.S. to increasingly rely on traditional fossil fuels and hinder the growth of the biomass alternative to these sources of energy.

## II. HARM TO SPECIFIC COMPANIES

### 1. Multi-State Paper Company

This company is a pulp, paper, and corrugated packaging company that has manufacturing facilities regulated by the Boiler MACT, CISWI and NHSM rules in five states. Compliance with these rules is of utmost importance to the company and will require a substantial capital investment by the company in addition to capital investments already made at affected facilities during 2004-2007 for compliance with the first Boiler MACT rule. Given the long lead time necessary to make the changes necessary to achieve compliance, the company will have to waste money on working toward compliance with the rule as promulgated, at the same time that EPA is reconsidering the rule.

EPA has identified substantial technical, legal, and regulatory requirements that must be re-evaluated during the reconsideration process. It is unclear what the full timeline for the reconsideration process will be. However, given the complex technical issues involving many different pollutants, technologies and diverse industry groups affected, it likely will take several months. EPA itself had requested a 15-month extension of the Boiler MACT issuance deadline from the courts in December 2010 in order to address the issues now up for reconsideration. The company cannot effectively plan for compliance during the pendency of the reconsideration action because it will not know what will be required under the rule until the proceeding is complete. If the rules remain effective during this reconsideration period, the company will not have time after the reconsideration action is complete to take the steps needed to comply with the rule.

It is imperative that the company be provided with certainty in regards to the regulatory applicability of emission units subject to the standards. Regulatory certainty means that companies must have all of the regulatory requirements of each of these rules in their final promulgated form; and must have sufficient time to develop an integrated and efficient implementation and compliance demonstration plan. Without regulatory applicability information in final form, company representatives cannot develop an efficient compliance demonstration strategy for each facility and for the company as a whole.

With promulgation of final rules on March 21, 2011, there remain a number of critical issues that must be addressed during the reconsideration process and that will have a very significant impact on company compliance strategy and capital allocation decisions, including decisions about which boilers will be modified or shut down, which fuels will fail to meet NHSM rules and can no longer be used as fuels in company boilers, whether certain boilers will be modified to comply with CISWI requirements, whether CO and D/F limits can be achieved, which control equipment is necessary for particulate and metal HAP control, and whether non-condensable gases (NCGs) produced in pulping and evaporation process areas (now considered "contained gases") can be burned in company power boilers as currently required by Subpart S NESHAPS. Each of these determinations must be finalized by EPA and the implications on mill operations, fuel contracts, compliance design projects, etc., completely understood prior to commencement of the 36-month compliance timeline.

Critical data elements that must be available to company engineers, regulatory managers and senior management – and which will not be available in "final form" for the pendency of the reconsideration action – include:

- Final compliance limits, averaging times and compliance demonstration methods for each regulated pollutant under each regulatory program (Boiler MACT or CISWI);

- Comprehensive information on available materials that meet NHSM requirements as "fuels";

- Comprehensive regulatory language and final determinations regarding materials currently used or anticipated for use that do not meet NHSM requirements and would subject boiler emission units to CISWI rules;

- Existing boiler and control equipment capabilities to meet the various emission limits under the Boiler MACT and CISWI MACT rules;

- Vendor guarantees to provide design and equipment to meet Boiler MACT and CISWI rules; and

- Information on fuels/wastes, control technologies and emissions impacts, with enough detail to allow for preparation of emissions inventories, regulatory applicability analyses and corresponding Title V and PSD permit modification application documents.

Without regulatory certainty at the beginning of the implementation process, the company risks squandering resources including design engineering costs, air permit timeline problems (provided in more detail below), installation of sub-optimum control equipment to meet final requirements, and ultimately, the risk of non-compliance with emission limits and compliance deadlines. Regulatory certainty is a key driver for investment in plant, property and equipment decisions in a capital-intensive industry like the pulp and paper industry. Inefficient project execution, squandering of limited resources, or failure to meet compliance deadlines is not an acceptable outcome and constitutes an irreparable harm to the company.

<u>There Will Not Be Sufficient Time After the Reconsideration Proceeding Is Complete to Comply With the Rules</u>

A critical path timeline is provided below based on information company engineers have obtained in conversations with and proposals from boiler manufacturers, equipment suppliers and vendors.

- Begin 36 month compliance timeline with promulgation of final Boiler MACT, CISWI and NHSM rule language.

- Months 0-3: final rule evaluation, fuels and boiler testing, identify gaps between existing control equipment and final regulatory requirements.

- Months 3-6: begin design engineering, complete air emissions review and begin preparation of Title V air permit modification applications, initiate request for vendor guarantees.

- Months 6-9: obtain vendor design guarantees, complete regulatory analyses, emissions modeling, regulatory NSR/PSD applicability review, BACT/LAER control technology review; address regulatory permitting issues and submit Title V air permit application to state and/or federal permit authorities.

- Months 6-24 (12-18 month average): It will be necessary in many cases to obtain a PSD permit due to increases in NOx emissions or other pollutants caused by fuel switches and the inverse relationship between CO and NOx pollutants. PSD permits are complex and the following steps are routinely necessary to obtain a final permit from state and/or federal air permit authorities, including: application review, "completeness" determination, BACT/LAER and regulatory review, modeling review, Title V permit preparation, negotiation and modification, 30-day public notice, 45-day EPA review, response to comments and permit issuance.

- Months 12-18: once air permit modification has received preliminary agency review and completeness determination, expected at approximately month 12, initiate final detailed design engineering with suppliers and engineering design firms, expected to take six months.

- Months 18-30: once the air permit modification is placed on public notice, initiate placement of order, expected at approximately month 18. Pressure parts, boiler generator tubes, and large fabricated equipment such as electrostatic precipitators and boiler grates have a lead time of 10-14 months from placement of orders (Jansen, B&W), if fabrication shops are available.

- Month 24: receipt of final Title V air permit modification. Beginning of actual construction cannot commence until receipt of final signed permit.

- Months 24-30: on-site construction (preparatory) work begins to include: receipt of ordered equipment, site preparation and foundation work, scheduling of manpower and detailed construction engineering plans to coincide with a major mill outage. Outage must occur prior to compliance deadline and must coincide with available customer, vendor and manpower availability. Furthermore, seasonal cold temperatures preclude shutdowns during certain time periods at various locations.

- Months 30-36: receipt of all equipment on site, mill outage scheduled, project construction completed prior to 36 month compliance deadline.

- Additional time needs: for new equipment demonstration and completion of preliminary emissions engineering tests, an additional 60-90 days is needed after the final construction and startup, prior to the 36-month compliance deadline.

Critical path timeline risks are significant for these projects and may include, but are not limited to delays caused by: permit authority staff availability, design engineering resource availability, control equipment and fabricators supply equipment and/or manpower availability, and delays in PSD permit review/approval at the state or regional EPA. As can be seen from the schedule above, the full 36 months from promulgation of final regulations is necessary. Even with the full 36 months, the schedule is still tight and subject to risk. Failure to provide a stay of the March 21, 2011, promulgated Boiler MACT, CISWI and NHSM regulations (60 day effective date) during the full term of

EPA's reconsideration process would produce a compliance deadline of approximately May 20, 2014. Given that all 36 months are essential to successful project implementation, reducing the schedule by any amount would be unacceptable from a project engineering, safety and environmental compliance standpoint, with consequences that would affect the company's compliance status and competitiveness. This is an unacceptable outcome and could cause irreparable harm to the company's operations facilities and the company.

**2. An Eastern Paper Mill**

There is No Plausible Control Strategy for Meeting the D/F Limit.

The extremely low level of the D/F emissions limit makes it impossible to plan on a compliance strategy for the combination boiler. The company cannot reliably measure to the level of the limit or find a contractor who can perform the testing, which means there is no way to reliably demonstrate compliance with the standard. If testing shows that control measures are needed, the company does not know what measures might be effective (if any) and, therefore, cannot determine the cost of compliance.

The Company's Residual Oil Boiler Will Have to Be Shut Down.

The company also operates a 100 mmBtu/hr residual oil-fired package boiler. The company has determined that the only viable compliance strategy is to replace this boiler with a natural gas boiler at a cost of $6.45 million. When this boiler is replaced with a new natural gas-fired package boiler, the company will effectively be limited to a single fuel because the new standards are so restrictive on oil combustion. The company anticipates that oil can only be permitted as a back-up during periods of gas curtailment, because boiler manufacturers are not willing to guarantee CO performance for new sources burning oil and the company is not independently able to determine that a well-designed and well-controlled boiler can reasonably be expected to meet those standards. The net result is the creation of a monopoly for the natural gas supplier, which will prevent the company from taking advantage of market conditions and maximizing the efficient use of limited resources by fuel switching. Thus, the rule creates substantial harm to the company by requiring the expenditure of additional significant resources to replace this boiler and limiting the operational flexibility of the replacement boiler.

Compliance with the Hg, and HCl Limits Will be Impractical.

This mill operates a 550 mmBtu/hr combination coal and biomass (wood) fired boiler. This "combination" boiler currently operates in compliance with a state-issued Title V Permit that includes CAA Section 112(j) provisions for the boiler. Under the terms of the final Boiler MACT rule, this boiler would have to be significantly modified at great expense. The boiler would have to be equipped with either more efficient scrubbers, a new baghouse with a new spray dryer, or a wet ESP to meet mercury and HCl limits. The amount of money required to retrofit this boiler to meet these requirements has been estimated to be $18 million. Investing this amount of capital with no return to the

company further limits the company's resources available for real economic growth and business development in its economically-depressed community.

**3. Paper Company in the Midwest**

Some Boilers Have No Viable Means of Compliance.

One of the company's mills has a boiler with a stack configuration that, under the current rule, makes it impossible to meet the rule's requirements. There are a series of investment scenarios envisaged at this time, and none of them can guarantee compliance at all times under the current final rule. Thus, there is no viable means of ensuring compliance for this boiler under the rule as it stands.

Applicability Is Uncertain and Necessary Control Measures Are Unavailable.

Under EPA's new interpretation of the term "contained gases," the company faces the possibility of having nine (9) of the company's 30 affected boilers considered as CISWI units, along with another twelve (12) units that are already covered under the Pulp and Paper MACT rules. The company currently has inadequate data to determination if the boilers can comply with the CISWI rule and it has not identified control measures—especially on lime kilns and chemical recovery boilers—that would ensure compliance with the rule and cannot reasonably determine that these issues can be resolved prior to the compliance deadlines.

The Carbon Monoxide Limits Are Not Achievable.

The current CO limits were established using stack test data and do not take into consideration operational variability, especially with biomass-fired boilers, where fuel quality variability (moisture, BTU value, etc) is highly variable. As a result, the ability to achieve continuous compliance with these limits has not been determined. In addition, the CO limits for liquid-fired boilers are simply unachievable with any new or retrofitted technologies. Also, the impact of low CO operations on NOx formation, and the potential PSD issues this might bring about, were not considered by EPA and may have significant compliance ramifications that extend beyond the MACT standard itself. Lastly, the company is concerned with the potentially conflicting data resulting from the mills' current obligation to operate a CO CEMS under Title V and other state permits and Boiler MACT's requirement to monitor CO continuous compliance using $O_2$ sensors.

There Is No Plausible Control Strategy for Meeting the D/F Limit.

Simply put, the current limits are, in some cases, below method detection limits. Thus, there is no viable way to reliably measure to the level of the standards. In addition, if it is determined that emissions of D/F must be reduced to meet the standard, the company has identified no current technologies that can be retrofitted to existing boilers to control this parameter. Even in cases where boilers are operated in optimum conditions, there are no guarantees that the D/F limits can actually be met, as no vendors will guarantee compliance with such low standards.

**4. Upper Midwest Paper Mill**

A paper mill in the upper Midwest relies on a 249 mmBTU/hr boiler fired mainly with wood to supply 70% of the paper mill's steam demand. Approximately 10% of the BTU load currently comes from coal. This 1980-vintage boiler has a multi-cyclone and a venturi scrubber. The current particulate matter limit is 0.08 lb/mmBTU while firing with wood and 0.10 lb/mmBTU while firing 100% coal. The existing source MACT standards for particulate matter of 0.039 lb/mmBTU and for D/F of 0.005 ng/dscm toxic equivalents (TEQ) at 7% $O_2$ present substantial difficulties. While additional or upgraded pollution control might be possible for particulate matter, the mill owners believe the limit may be unachievable. As for D/F, extensive testing that has already been performed shows that D/F is present when burning coal. The mill owners cannot currently stop burning coal and are not aware of control measures that will ensure continuous compliance with the limit. Inability to run this boiler will lead to a mill shut down.

Another problem is with wood oil fuel that is obtained from a nearby company. Since this company produces more of this material than they can use during the production of other products, the paper mill uses this material as a fuel to offset some natural gas usage. This material is currently burned in just one of the mill's boilers; however, it is permitted to be used in another – both of which are different than the wood/coal boiler noted above. A call made to the EPA questioning whether combustion of this fuel would be subject to the new rules has gone unanswered. Therefore, applicability of the industrial boiler MACT to the combustion of this fuel remains an open question. If the rule applies, it is possible that the mill would switch back to just burning natural gas; however, this is contrary to the company's goal of becoming a fossil-fuel-free manufacturer.

**5. Northwestern Lumber Mill**

The cost of complying with the final Boiler rule likely will have a material economic impact on the company, significantly impacting its competitiveness**.** The company has a 64 mmBtu/hr wood waste boiler that produces steam for use at two of its drying kilns. The boiler fires only wood residuals consisting mainly of green sawdust from the sawmill and hogged bark from the debarker. The boiler also fires small amounts of planer mill shavings, hogged scrap green lumber from the sawmill and hogged finished lumber from the planer mill.

Even assuming the company can meet the standards with applicable control equipment, the national economy has been causing the wood products industry, including this company, a very tough time. In fact, the industry may have been one of the first industries to feel the crunch.

During this difficult time, the company continues to try to innovate and create better service, better quality products, etc., to differentiate itself from the crowd, but due to increasing competitive pressure from both domestic and international producers, a major key to survival continues to be the ability to be the low-cost producer.

As such, as a relatively small player in this industry, the company must scrutinize capital expenditures very carefully, not only to ensure it can meet all of its business obligations, but also to help ensure its expense structure will allow it to compete with bigger domestic and international players that can sometimes better utilize economies of scale.

**6. Multi-mill Paper Company**

In light of the announced plan for reconsideration of the solid fuel subcategory, this company is unable to decide whether additional controls will be required for additional units. If the sub-categorization mechanisms are changed during reconsideration, then it is likely that the emission limits would also change. This could result in wasted capital should the standards become less stringent. However, the worse case is in the event that the standards are made more stringent due to actions taken during reconsideration. Without a stay of the effective date of the rule, the company will be faced with irreparable harm due to insufficient time to engineer and implement control strategies for units that presently would not require additional control. In essence without a stay to the rule, these units would not be allotted the full three years to comply as all other units regulated by Boiler MACT would have.

**7. A Chemical Manufacturing Plant**

<u>The Prospect That the Liquid Fuel Standards Will Apply Likely Will Force the Company to Replace a Clean-Burning Liquid Fuel With Natural Gas</u>.

The plant is a major HAP source and last year burned 731,000 gallons per year of comparable (clean) liquid fuels (primarily alcohols) in a boiler that also burns 25.5% hydrogen and 43.9% natural gas. This liquid fuel was considered a hazardous waste prior to 1997 (i.e., before EPA promulgated the comparable fuel rule).

The company believes that burning clean fuels will put this boiler into the liquid fuel category because liquids supply 30.6% of the total annual Btu input. As a result, to continue burning the liquid fuel, it would have to spend thousands of dollars to install an access platform, monorail, and sampling ports to determine if it can meet the new Boiler MACT CO limit (10 ppm). Aside from the costs of control measures needed to ensure compliance with the standards, the annual stack test will also impose substantial costs ($30,000 - $40,000 per year).

If the company replaced the clean liquid fuel with natural gas it may be able to opt-in to the gas 1 subcategory (assuming that opt-in provision is not changed through agency reconsideration). In doing so, it would avoid the costs of meeting the liquid-fuel standards and it would send the clean liquid fuels off-site for incineration. However, replacing the clean liquid fuels with natural gas overall would increase GHG and NOx emissions.

**8. A Multi-State Forest Products Company**

<u>There is no plausible way to ensure compliance with the Boiler MACT D/F standard.</u> The Boiler MACT D/F standard is not achievable for many company facilities due to

uncertainty concerning dioxin generation and dioxin-specific pollution control techniques. Absent a stay of the rule pending reconsideration, the company will be required to ensure compliance with the new dioxin limit without any demonstrated mechanism of achieving such compliance. This challenge will cause irreparable harm to the company in two primary ways:

- Expenditure of significant capital costs for new pollution control technology that may not work; and

- shuting down facilities if, after exhausting all known dioxin control strategies, it is unable to demonstrate compliance with the Boiler MACT's dioxin emission limit .

The company has completed dioxin emission testing of most of its large boilers to determine if compliance can be achieved at those sources. Ten boilers reported levels of dioxin emissions that exceed the Boiler MACT's dioxin emission limit. Additionally, the variability in the data suggests that the company could not assure compliance in one additional boiler. In total, the company's dioxin emission testing suggests that at least 11 boilers cannot presently ensure compliance with the Boiler MACT dioxin emission limit.

Based on recent research completed by the National Council for Air and Stream Improvement (NCASI), it is unclear what, if any, pollution control strategy the company could employ to bring these boilers into compliance and ensure continuous compliance thereafter with the Boiler MACT's dioxin emission limit. NCASI's recent research attempted to identify the variables associated with dioxin generation within industrial boilers. The results of this research suggest that dioxin generation cannot be predicted, and therefore the company does not know what process variables can be manipulated to demonstrate compliance with the Boiler MACT's dioxin limit. Although EPA has identified Activated Carbon Injection (ACI) as a dioxin control technology, the company has not been able to locate any data that would demonstrate that ACI is capable of reducing dioxin emissions to the very low levels required to meet the Boiler MACT's dioxin emission limit. Nevertheless, as the Boiler MACT dioxin emission limit currently stands; the company would be compelled to expend significant resources to install ACI at those units for which compliance cannot be ensured.

In sum, if allowed to stand in its present form, the Boiler MACT's dioxin emission limit would impose a requirement that many company facilities presently cannot meet, and for which there is currently no demonstrated practice or technology that can be implemented to ensure compliance. Under these circumstances, the company will suffer irreparable harm not only in spending significant resources on the chase for a compliance solution that may not exist, but also having to shut down facilities for which it is unable to ensure continuous compliance with the Boiler MACT's dioxin emission limit.

**9. Multi-State Forest Products Company**

Meeting the final emissions standards will be inordinately costly and, in some cases, no method of ensuring compliance has been identified. The company operates affected industrial boilers at three facilities. Information on these boilers is summarized below:

**Facility 1. Boiler MACT Applicable Sources**

| | | |
|---|---|---|
| **Boiler** | Power Boiler | Power Boiler |
| **Type** | Stoker | -- |
| **Fuel** | Biomass/Sludge | Natural Gas/No. 2 Distillate Oil |
| **Maximum Firing Rate (MMBtu/hr)** | 595 | 250 |
| **Current Control** | Over-fired Air/Dust Collector/ESP | None |
| **Purpose** | Provide Steam to Turbine for Power Generation and to Kraft Mill | Provide Steam to Kraft Mill |

**Facility 2. Boiler MACT Applicable Sources**

| | | |
|---|---|---|
| **Boiler** | Hog Fuel Boiler | Natural Gas Boiler |
| **Type** | Fuel Cell (Wellons system) | -- |
| **Fuel** | Biomass (hog fuel) | Natural Gas |
| **Maximum Firing Rate (MMBtu/hr)** | 200 Mlb/hr of steam | 31.2 |
| **Current Control** | Multiclone, ESP | None |
| **Purpose** | Provide Steam to Lumber Drying Kilns | -- |

**Facility 3. Boiler MACT Applicable Sources**

| | | |
|---|---|---|
| **Boiler** | Wastewood Boiler | Gasification Boiler |

| | | |
|---|---|---|
| **Type** | Stoker | Stoker |
| **Fuel** | Biomass (bark) | Biomass (bark) |
| **Maximum Firing Rate (MMBtu/hr)** | 63.7 | 28.7 |
| **Current Control** | Multiclone, ESP | Dust Collector |
| **Purpose** | Provide Steam to Lumber Drying Kilns | |

Summary of Applicable Requirements: The following tables list emission standards applicable to these boilers. The table indicates whether the emission limit is for a pollutant not currently regulated for that boiler (no emission limit in the current permit). For the pollutants that are currently regulated, the table shows the reduction over the current emission limits.

**Facility 1. Applicable Standards**

| **Boiler** | **Fuel** | **Source Category** | **Pollutant** | **MACT Standards (in units of lb/mmBtu unless otherwise noted)** | **New Requirement?** |
|---|---|---|---|---|---|
| Power Boiler | NG/ #2 Oil | Existing Liquid Fuel Boiler | PM | 0.0075 | 94% of current limit |
| | | | HCl | 0.00033 | Yes |
| | | | Hg | 0.0000035 | Yes |
| | | | CO | 10 ppm @ 3% O2 | Yes |
| | | | Dioxin | 4 TEQ ng/dscm[1] | Yes |
| Power Boiler | Wood | Existing Biomass Boiler (Stoker) | PM | 0.039 | 61% of current limit |
| | | | HCl | 0.035 | Yes |
| | | | Hg | 0.0000046 | Yes |
| | | | CO | 490 ppm @ 3% O2 | 18% of current limit |

| | | | | | |
|---|---|---|---|---|---|
| | | | D/F | 0.005 TEQ ng/dscm | Yes |

Note: PM = particulate matter, HCl = hydrogen chloride, Hg = mercury, CO = carbon monoxide, D/F = dioxins and furans, ppm = parts per million, ng = nanograms, dscm = dry standard cubic meter

1. Corrected to 7% O2 (dry).

**Facility 2. Applicable Standards**

| **Boiler** | **Fuel** | **Source Category** | **Pollutant** | **MACT Standards (in units of lb/mmBtu unless otherwise noted)** | **New Requirement?** |
|---|---|---|---|---|---|
| Fuel Cell | Wood | Existing Biomass Boiler (Fuel Cell) | PM | 0.039 | 61% of current limit |
| | | | HCl | 0.035 | Yes |
| | | | Hg | 0.0000046 | Yes |
| | | | CO | 690 ppm @ 3% O2 | Yes |
| | | | D/F | 4 TEQ ng/dscm[1] | Yes |

Note: PM = particulate matter, HCl = hydrogen chloride, Hg = mercury, CO = carbon monoxide, D/F = dioxins and furans, ppm = parts per million, ng = nanograms, dscm = dry standard cubic meter

1. Corrected to 7% O2 (dry).

**Facility 3. Applicable Standards**

| **Boiler** | **Fuel** | **Source Category** | **Pollutant** | **MACT Standards (in units of lb/mmBtu unless otherwise noted)** | **New Requirement?** |
|---|---|---|---|---|---|
| Wood | Wood | Existing Biomass Boiler (Stoker) | PM | 0.039 | 94% of current limit |
| | | | HCl | 0.035 | Yes |
| | | | Hg | 0.0000046 | Yes |

| Boiler | Fuel | Source Category | Pollutant | MACT Standards (in units of lb/mmBtu unless otherwise noted) | New Requirement? |
|---|---|---|---|---|---|
| | | | CO | 490 ppm @ 3% O2 | Yes |
| | | | D/F | 0.005 TEQ ng/dscm | Yes |
| Gasify | Wood | Existing Biomass Boiler (Stoker) | PM | 0.039 | 90% of current limit |
| | | | HCl | 0.035 | Yes |
| | | | Hg | 0.0000046 | Yes |
| | | | CO | 490 ppm @ 3% O2 | Yes |
| | | | D/F | 0.005 TEQ ng/dscm | Yes |

Note: PM = particulate matter, HCl = hydrogen chloride, Hg = mercury, CO = carbon monoxide, D/F = dioxins and furans, ppm = parts per million, ng = nanograms, dscm = dry standard cubic meter

1. Corrected to 7% O2 (dry).

Testing and monitoring: In addition to meeting these emission limits, the boilers would also be subject to the testing and monitoring requirements presented in the following tables. Note that these tables only list the new requirements from the Boiler MACT. For example, one power boiler is required to continuously monitor $O_2$ under the Boiler MACT, but $O_2$ is already monitored at this source.

**Facility 1. Additional Compliance Requirements**

| Boiler Name | Source Category | Testing Requirement | Compliance Requirement |
|---|---|---|---|
| Power Boiler | Existing Liquid Fuel Boiler | Initial & annual testing. However, one-time compliance demonstration (testing) for dioxin/furan | (1) Install PM CEMS, (2) Continuous O2 Monitor, (3) If burning multiple fuels, maintain fuel mixture Hg and Cl content at or below the maximum fuel input levels established during initial performance testing, and (4) One-time energy assessment and cost-effective energy conservation measures |

| Boiler Name | Source Category | Testing Requirement | Compliance Requirement |
|---|---|---|---|
| Power Boiler | Existing Biomass Boiler (Stoker) | | (1) Install PM CEMS, (2) If burning multiple fuels, maintain fuel mixture Hg and Cl content at or below the maximum fuel input levels established during initial performance testing, (3) Operate Bag Leak Detection System, (4) Maintain Daily block average opacity <10%, and (5) One-time energy assessment and cost-effective energy conservation measures |

**Facility 2. Additional Compliance Requirements**

| Boiler Name | Source Category | Testing Requirement | Compliance Requirement |
|---|---|---|---|
| Fuel Cell Boiler | Existing Biomass Boiler (Fuel Cell) | Initial & annual testing. However, one-time compliance demonstration (testing) for dioxin/furan | (1) Install PM CEMS, (2) If burning multiple fuels, maintain fuel mixture Hg and Cl content at or below the maximum fuel input levels established during initial performance testing, (3) Maintain Daily block average opacity <10%, and (4) One-time energy assessment and cost-effective energy conservation measures |
| Natural Gas Boiler | Existing Natural Gas Boiler | None | (1) Annual tune-up, (2) performance of an energy assessment, and (3) identify cost-effective energy conservation measures |

**Facility 3. Additional Compliance Requirements**

| Boiler Name | Source Category | Testing Requirement | Compliance Requirement |
|---|---|---|---|
| Wood | Existing Biomass Boiler | Initial & annual testing. However, one-time compliance | (1) Maintain Daily block average opacity <10%, and (2) One-time energy assessment and cost-effective |

| Boiler Name | Source Category | Testing Requirement | Compliance Requirement |
|---|---|---|---|
| | (Stoker) | demonstration (testing) for dioxin/furan | energy conservation measures |
| Gasify | Existing Biomass Boiler (Stoker) | Initial & annual testing. However, one-time compliance demonstration (testing) for dioxin/furan | (1) Operate Bag Leak Detection System or Maintain daily block average opacity <10%, and (2) One-time energy assessment and cost-effective energy conservation measures |

Consequences of Compliance: Current testing has been reviewed for these units to complete a preliminary assessment of the compliance needs. An expert in boiler engineering and combustion reviewed the data and suggested a control strategy for compliance. Note that this was not a detailed engineering analysis, but rather a paper study to get a general idea for the compliance status of each source. The estimated capital and annualized costs were also determined. The following tables summarize the recommendations. A question mark "?" indicates the pollutant has not been tested yet and, therefore, no baseline established. For these pollutants, the suggested control strategy is based on experience with similar boilers. Establishing compliance where no data are available for current units is extremely difficult.

**Facility 1. Summary of Control Scenario for Compliance**

| Boiler | Fuel | Pollutant | Existing Controls | Estimated Additional Control Efficiency Required (%) | Suggested Control Technology (if needed) | Costs ($1,000) (if needed) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Capital | Annual |
| Power Boiler | NG #2 Oil | PM | None | 96 | ESP | 2,100 | 500 |
| | | HCl | | 98 | SDA | 2,540 | 190 |
| | | Hg | | ? | None | -- | -- |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | CO | | 87 | OxCat | 930 | 60 |
| | | D/F | | ? | None | -- | -- |
| Power Boiler | Wood | PM | ESP | 99 | Baghouse | 3,100 | 650[2] |
| | | HCl | None | 58 | SDA | 3,620 | 500 |
| | | Hg | None | None | None | -- | -- |
| | | CO | OFA | None | Tune-ups | -- | 20 |
| | | D/F | None | ? | ACI[1] | 865 | 400 |

Notes: ACI = activated carbon injection, SDA = spray dryer absorber, OFA = overfire air system, OxCat = oxidation catalyst, DSI = dry sorbent injection

1. If deemed necessary following testing.

2. Includes bag replacement and does not include ash disposal.

**Facility 2. Summary of Control Scenario for Compliance**

| **Boiler** | **Fuel** | **Pollutant** | **Existing Controls** | **Estimated Additional Control Efficiency Required (%)** | **Suggested Control Technology (if needed)** | **Costs ($1,000) (if needed)** | |
|---|---|---|---|---|---|---|---|
| | | | | | | **Capital** | **Annual** |
| Fuel Cell | Wood | PM | ESP | None | None | -- | -- |
| | | HCl | None | ? | DSI[1] | 400 | 100 |
| | | Hg | | ? | ACI[1] | 575 | 220 |
| | | CO | | None | Tune-up | -- | 15 |
| | | D/F | | ? | ACI[1] | 0[2] | 0[2] |

Notes: ACI = activated carbon injection, SDA = spray dryer absorber, OFA = overfire air system, OxCat = oxidation catalyst, DSI = dry sorbent injection

1. If deemed necessary following testing.

2. Includes bag replacement and does not include ash disposal.

**Facility 3. Summary of Control Scenario for Compliance**

| Boiler | Fuel | Pollutant | Existing Controls | Estimated Additional Control Efficiency Required (%) | Suggested Control Technology (if needed) | Costs ($1,000) (if needed) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Capital | Annual |
| Wood | Wood | PM | ESP | 99 | Baghouse | 805 | 150[2] |
| | | HCl | None | ? | DSI[1] | 250 | 50 |
| | | Hg | | ? | ACI[1] | 225 | 80 |
| | | CO | | ? | OFA[1] | 300 | 25 |
| | | D/F | | ? | ACI[1] | 0[3] | 0[3] |
| Gasify | Wood | PM | Collector | 82 | Baghouse | 510 | 100[2] |
| | | HCl | None | ? | DSI[1] | 250 | 30 |
| | | Hg | | ? | ACI[1] | 140 | 55 |
| | | CO | | ? | Tune-up | ? | 20 |
| | | D/F | | ? | ACI[1] | 0[3] | 0[3] |

Notes: ACI = activated carbon injection, SDA = spray dryer absorber, OFA = overfire air system, OxCat = oxidation catalyst, DSI = dry sorbent injection

1. If deemed necessary following testing.

2. Includes bag replacement and does not include ash disposal.

3. ACI costs for Dioxin control included with cost of Hg control (if needed).

General Concerns with Feasibility

The company is not aware of any biomass sources using activated carbon for control of dioxins and mercury. The combination of controls that may be necessary on some units (e.g. SDA followed by ACI followed by baghouse) is also unproven to meet the standards for a biomass boiler. There is limited information on whether compliance is achievable and no existing data demonstrating these controls or combination of controls will bring the boiler into compliance. The company is aware of limited cases where SDA has been applied to a biomass boiler; these boilers are between 150 MMBtu and 250 MMBtu whereas the company's biggest power boiler is 595 MMBtu/hr.

Furthermore, SDA and ACI controls have proven effective on controlling emissions from waste incinerators which have a much higher baseline. For comparison, the New Source Performance Standard (NSPS) emission limits for dioxin/furan for solid waste incinerators is 0.13 ng/dscm (new) or 0.41 ng/dscm (existing)[1] as compared to 0.005 ng/dscm for existing biomass stoker boilers. In other words, the best performing existing incinerators have emissions 82 times higher than the best performing existing biomass stoker boilers and emissions are 26 times higher for new incinerators. A control device will generally perform better (higher control efficiency) when the baseline concentrations are high. Installing controls that have not been proven to be able to meet these MACT standards on a biomass boiler is a high risk scenario.

Particular Concerns with Burning Salty Fuel

Although EPA calls Dioxin/Furan "combustion-based pollutants," these emissions are dependent on the chloride content of the fuel, similar to HCl. HCl and Dioxin/Furan emissions are higher for boilers that burn salt-laden wood (wood transported via ocean log booms and wood from coastal forests) because of the relatively high chloride content of the wood. The chloride content of salt-laden wood can be in the range of 0.8%, whereas non-salted wood typically has chloride content less than 0.01%.[2]

Chloride content in the company's biomass is higher than the national average because the biomass contains wood from high alkali soils or coastal forests, and logs transported on salt water. The company also burns waste treatment sludge in its boilers. To reduce fresh water usage, the company uses direct cooling of effluent prior to the activated sludge treatment process. The cooling media is salt water pumped directly from an ocean bay. This adds salt load that ends up in the secondary treatment sludge. This sludge is dewatered and burned in a boiler. Chloride in the company's biomass fuel (mixture) ranges from 35 to 5,630 ppm and has an average chloride content of 1,109 ppm (or 0.11%). The table below shows the chloride concentration of fuel burned by the company and data collected by the National Council for Air Stream Improvement (NCASI).

**Chloride Concentration in Fuel mg/kg (ppm)**

| **Source** | **Minimum** | **Maximum** | **Mean** | **Standard Deviation** |
|---|---|---|---|---|
| NCASI Bark | <40 | 273 | 90 | -- |
| NCASI Stemwood(1) | 50 | 91 | 62.4 | -- |
| Company Fuel Mixture(2) | 35 | 5,630 | 1,109 | 780 |

[1] 40 CFR Subpart CCCC

[2] "Emissions from Wood-Fired Combustion Equipment," British Columbia Ministry of Environment, June 30, 2008.

(1) NCASI Technical Bulletin No 875, Nationwide Evaluation Of Mercury And Chlorine Levels In Bark And Stemwood, April 2004.

(2) From 75 samples tested between March 2005 and December 2006.

As shown in the table above, local chloride concentrations are higher than the national average. The company's chloride concentrations are similar to other local chloride concentrations. Typically, dioxin/furan emissions from facilities burning salt-laden wood residue are considerably higher than those from facilities burning non-salty wood.[3] Average emission factors are 0.56 ng /kg wood for non-salty wood combustion and 13.2 ng /kg wood for salt-laden wood combustion (24 times higher than non-salty wood).[4] Without a separate subcategory for salty and non-salty fuel, the implication for facilities that burn salt-laden fuel is a requirement to install expensive controls that have not been proven to work for the source type (as discussed above) or switch to non-salty fuel in order to comply with the standard. EPA did not consider this for the cost impact analysis of the rule. More specifically, EPA's cost analysis did not include add-on controls for any of the affected sources mentioned here.

Controls of dioxin/furan using ACI are estimated to cost $900,000 for capital investment and $400,000 per year in annual expenses. EPA suggests a combination fabric filter and dry injection (DIFF) system for boilers located at wood products or paper manufacturing facilities. However, the company's preliminary analysis indicates DIFF will not provide enough HCl control to meet the Boiler MACT emission limit (at least 98% control necessary) for its boiler. An SDA system is the only technology of which it is aware that has been proven to provide this level of control. Estimated cost for SDA is $3,600,000 for capital investment and $500,000 per year in annual expenses. Inlet grain loading to the existing ESP will increase with the salts and carbonaceous PM formed by the SDA and ACI. Replacement of the ESP with a baghouse will likely be needed to maintain emissions below the PM limits. Estimated cost for the baghouse is $3,100,000 for capital investment and $650,000 per year in annual expenses (includes bag replacement and does not include ash disposal). Therefore, total cost for HCl and dioxin/furan compliance is estimated at $7,600,000 for capital investment and $1,600,000 per year in annual expenses.

The biomass supplied to the company comes from up to 20 different suppliers, most of which are sawmills or log chippers that remove the bark and grind it up to create the fuel. The company receives building and demolition waste in lesser quantities. The company also uses screenings of the wood chips supplied to the digester for pulp production, called fines. The final source of fuel to the boiler is the waste treatment sludge, both primary and secondary, from the mill waste treatment system. The secondary sludge typically contains over 1,000 mg/kg of chloride and is roughly 50% of the chloride load going to

[3] NCASI summary of PCDD/F emission from wood residue and black liquor combustion. Attachment 2 to comments on EPA's external review draft Estimating Exposures to Dioxin-Like Compounds. January 13, 1995.

[4] EPA/600/P-03/002F, An Inventory of Sources and Environmental Releases of Dioxin-Like Compounds in the United States for the Years 1987, 1995, and 2000. November 2006.

the boiler. Fuel costs would increase if the fuel supplies with high chloride content were eliminated and replaced with low-chloride-content biomass. The cost to replace these suppliers is approximately $1.5 million/year. If the sludge is not burned in the power boiler, it would have to be landfilled. The cost to haul this sludge to landfill instead of burning it would be approximately $1 million per year. There would also be additional cost associated with replacing the sludge with biomass fuel of approximately $700,000 per year. Therefore, the total cost of removing fuel with the highest chloride content is $3.2 million per year.

EPA states in the final rule:

> *Finally, EPA has changed the dioxin/furan testing requirement to a one-time compliance demonstration due to the low dioxin/furan emissions demonstrated by the vast majority of sources that have tested for dioxin/furan.* [15618 Federal Register / Vol. 76, No. 54]

EPA's cost analysis does not estimate any control costs for achieving the dioxin/furan emission limits. If boilers have such relatively low dioxin/furan emissions, EPA should reconsider whether emission limits are necessary at all and reevaluate its cost analysis considering any facilities burning salt-laden fuel will likely need expensive controls to meet the standard. Salt-laden wood is still an important source of fuel for the wood products and paper manufacturing industry. If salt-laden wood becomes prohibitive to combust in the boiler due to the Boiler MACT, other disposal options for this biomass would be needed, such as landfill or transportation off-site for an unknown use. In addition, other sources of fuel such as wood from non-coastal areas or fossil-fuel would be needed to replace the loss of salt-laden wood fuel. This is counterproductive for sustainability and is backwards thinking, considering that the industry has been created for full utilization of the biomass resource.

Non-waste Determination and Applicability to CISWI vs Boiler MACT

The biomass combusted in the company's boilers is a combination of bark, chips, sawdust, shavings, building and demolition waste (in lesser quantities), screenings of the wood chips supplied to the digester for pulp production, and waste treatment sludge from the mill waste treatment system. EPA has not made a decision on whether any of these fuel streams is considered waste and, consequently, subject to 40 CFR Subpart CCCC, NSPS for solid waste incinerators. The company is hesitant to move forward with implementing a compliance strategy until this issue is resolved; however, given the tight timeline for compliance (deadline in three years), quick action is necessary to ensure compliance can be demonstrated in time.

Alternative Compliance Scenario

Alternative to installing controls, the biomass boilers could be converted to natural gas in order to come into compliance. For boilers already capable of burning natural gas, the only cost associated with this conversion would be the difference in fuel cost. Although

this is a cost effective option for compliance with Boiler MACT, it does not support local, state, and national renewable energy initiatives. Biomass combustion for energy (steam for manufacturing or power) is an important renewable energy resource across the country. The company installed a steam turbine generator in 2009 to produce green power from extra capacity on one of its biomass boilers. This green energy is used at the facility and excess power is sold to the grid. When operating in a stand-alone electric generating mode the plant can produce 27 MW, making the facility the largest single combined heat-and-power renewable energy project built in the U.S. in the last 10 years.[5] This would also require disposal options of the biomass such as landfill or transportation for an unknown use. This is counterproductive for sustainability and is backwards thinking, considering that the industry has been created for full utilization of the biomass resource.

Concern of Cost:

The cost in the tables below represents the cost estimated for the controls expected based on the preliminary compliance status evaluation where a baseline emission level has been estimated. These controls will be necessary based on current test data available for each unit. The tables also present the cost associated with an alternative compliance scenario of switching to non-salty wood fuel for relevant boilers. Note this does not include cost for compliance testing and monitoring; additional capital and annual expenses are expected to meet those requirements. Testing and monitoring cost presented in the tables are the maximum of the range of costs estimated by several vendors. Initial testing cost includes a complete test series on all five pollutants. The D/F tests will be required only once if the source is in compliance with the Boiler MACT standard and subsequent tests will be less expensive without D/F. Certain boilers are expected to have D/F emissions below the Boiler MACT standard. However, D/F testing is expected to be required annually. Monitoring cost presented below includes the one-time energy assessment and installation of PM continuous emissions monitoring system (CEMS).

**Facility 1. Anticipated Cost for Achieving Compliance**

| **Expense** | **Boiler** | **Maximum Cost ($1,000)** | |
|---|---|---|---|
| | | **Capital** | **Annual** |
| **Scenario 1: Controls** | | | |
| Controls | Power Boiler | 5,500 | 760 |
| | Power Boiler | 7,600 | 1,620 |

[5] USA Biomass Power Producers Alliance.

| | | | |
|---|---|---|---|
| | Total | 13,100 | 2,380 |
| Testing | All | 80 | 65 |
| Monitoring | All | 180 | 150 |
| **Total** | **All** | **13,360** | **2,595** |
| **Scenario 2: Fuel Changes and Controls** | | | |
| Controls | Power Boiler | 5,500 | 760 |
| Fuel Changes | Power Boiler | 0 | 3,200 |
| Testing | All | 80 | 65 |
| Monitoring | All | 180 | 150 |
| **Total** | **All** | **5,760** | **4,175** |

**Facility 2. Anticipated Cost for Achieving Compliance**

| **Expense** | **Minimum Cost ($1,000)** | | **Maximum Cost ($1,000)** | |
|---|---|---|---|---|
| | **Capital** | **Annual** | **Capital** | **Annual** |
| Controls | 0 | 20 | 1,000 | 320 |
| Testing | 40 | 25 | 40 | 40 |
| Monitoring | 65 | 75 | 90 | 75 |
| **Total** | **105** | **120** | **1,130** | **435** |

**Facility 3. Anticipated Cost for Achieving Compliance**

| **Expense** | **Boiler** | **Minimum Cost ($1,000)** | | **Maximum Cost ($1,000)** | |
|---|---|---|---|---|---|
| | | **Capital** | **Annual** | **Capital** | **Annual** |

| | | | | | |
|---|---|---|---|---|---|
| Controls | Wood | 800 | 200 | 1,600 | 360 |
| | Gasify | 500 | 120 | 900 | 210 |
| | **All** | **1,300** | **320** | **2,500** | **570** |
| Testing | **All** | **80** | **50** | **80** | **80** |
| Monitoring | **All** | **5** | **0** | **5** | **0** |
| **Total** | **All** | **1,385** | **370** | **2,585** | **650** |

Initial research into control technologies leaves doubt to their efficacy in meeting the Boiler MACT standards. This is not an "either/or" solution, but one that will probably require substantial fuel changes along with the control technologies to ensure compliance with the standards. The company believes that certain boilers will have to be decommissioned and the process heat requirements will have to be met by other means. The equipment, installation, and annual costs would significantly increase the capital required to produce process heat at its facilities. Given the real possibility of substantial capital costs for control devices and monitoring devices (and, possibly, boiler replacements), substantial fuel changes and associated cost increases, substantially increased fuel testing requirements and associated costs, along with the very limited capital available in a very competitive business, along with the short time for a relatively small company to generate significant capital before expenditures are required, the viability of the company's facilities is really called into question.

**10. Softwood Lumber Manufacturer**

Boiler MACT Compliance Costs Are Particularly Onerous in Light of the Ongoing Deep Recession.

Softwood lumber mills are experiencing historically low product demand and low product pricing, mostly related to a historic drop-off in domestic housing starts. Four lumber manufacturing mills located in the southern U.S. (and described below) have experienced negative gross margins over the past three years and their ongoing operation was supported by the parent company. The parent company has been spending money to keep these facilities in business. However, these conditions also have led to adjustments in the number of operating facilities to respond to the market demand loss. For example, this softwood lumber business has closed many North American mills, dropping from 32 mills in 2006 to 19 at the end of 2010[6]. Economic forecasts are for these conditions to improve on only a limited basis over the next three years. Because of these economic conditions, the parent company must weigh the overall cost to comply with Boiler MACT

[6] The parent company acknowledges that other considerations also influence decisions on maintaining operations at individual facilities, but the loss of market demand was the overriding factor during this period.

against the funds available and economic outlook for these facilities. As a result, continuing operations at these facilities remain at risk and, unfortunately, so do the jobs of the 587 employees at these mills.

The current state of uncertainty with the Boiler MACT final provisions is especially problematic. Additional characterization of source emissions, engineering, control technology evaluation, capital appropriation, etc., must begin soon to achieve the regulatory compliance date in March 2014. However, until there is final resolution on control parameters and emissions limits, the risk is that funds will be misspent, and the activity and cost may need to be repeated. Due to the home building downturn and resulting poor market conditions, these lumber mill operations cannot withstand misspent funds. Given the losses of the past few years and no recovery on the horizon, capital funding is quite limited.

The parent company estimates that initial capital for controls and other improvements to comply with Boiler MACT for these four mills total over $22 million. However, at each of the four mills, there is a high level of uncertainty whether the boilers will need specific controls to meet the dioxin/furan limits. This uncertainty arises since accurate measurements of these emissions are unavailable, test results are likely to be uncertain given the emission levels for these types of boilers, and fuels are expected to be at or below the error margins of the test methodology. In addition, initial engineering review has not found any evidence of reliable control technology for achieving emission limits at the low levels required by the final rule. And, with the final rule reconsideration that is pending based on EPA's own notice (and additional petitions for reconsideration and judicial review likely from industry and other stakeholders), it will be difficult to spend funds even for initial additional testing and engineering design when the outcome of the reconsideration on the dioxin/furan limits, – and thus actual need for some of the control technology – remains in question. Similarly, the final outcome for particulate matter (PM) and carbon monoxide (CO) limits for these facilities remains a complicating uncertainty. Therefore, without adequate deferral of the compliance deadlines, decisions on the continued operation of these mills will have to be made with potentially highly inaccurate estimates of capital needs for the control equipment. This is an untenable position for the business decision makers and could result in harm to the facilities, as compliance planning will have to assume worst case on emission limits and control technology needs during the period of time the reconsideration process runs its course. For these reasons a stay of the compliance deadline for the length of the reconsideration process must be provided.

The five boilers at the four mills (outlined below) are all in the same subcategory: spreader stoker design and units designed to burn biomass fuel (i.e., hogged fuel). Three of the five boilers appear unable to meet the current final rule CO limit for the subcategory, and all of the boilers appear unable to meet the current final rule PM and dioxin/furan limits for the subcategory. Each of these limits seems likely to be reconsidered and, therefore, the uncertainty of the ultimate final limits is high for each of these mills.

Case 1 –Softwood lumber mill

- 70 MMBtu/hr, spreader stoker, hog fuel

- Currently appears not able to meet or uncertain whether can do so:

    - 490 ppm @ 3%O2 (eq. to 0.39 lb/MMBtu heat input) limit for Carbon Monoxide

    - 0.005 TEQ ng/dscm @ 7% O2 for Tetrachlorinated Dioxins/Furans

    - 0.039 lb/MMBtu heat input limit for filterable Particulate Matter

- Estimated capital cost of $2.1 million for CO control (either overfire air or CO catalyst, and CEMS for O2); uncertain if additional control for D/F will also be necessary.

- Estimated capital cost of $2.4 million for PM control (addition of ESP and COM)

- This mill was ready to meet the original Boiler MACT health-based compliance alternative for the metal HAPs.

Case 2 – Softwood lumber mill

- 140 MMBtu/hr, spreader stoker, hog fuel

- Currently appears not able to meet or uncertain whether can do so:

    - 490 ppm @ 3%O2 (eq. to 0.39 lb/MMBtu heat input) limit for Carbon Monoxide

    - 0.005 TEQ ng/dscm @ 7% O2 for Tetrachlorinated Dioxins/Furans

    - 0.039 lb/MMBtu heat input limit for filterable Particulate Matter

- Estimated capital cost of $2.1 million for CO control (either overfire air or CO catalyst, and CEMS for O2); uncertain if additional control for D/F will also be necessary.

- Estimated capital cost of $3.6 million for PM control (addition of ESP and COM)

- 29 MMBtu/hr, spreader stoker, hog fuel

- Currently appears not able to meet or uncertain whether can do so:

    - 0.005 TEQ ng/dscm @ 7% O2 for Tetrachlorinated Dioxins/Furans

    - 0.039 lb/MMBtu heat input limit for filterable Particulate Matter

- Highly uncertain estimated capital cost of $1 million for D/F control (either combustion controls or activated carbon injection with high annual operating costs)

- Estimated capital cost of $1.4 million for PM control (addition of ESP and COM)

- This mill was ready to meet the original Boiler MACT health-based compliance alternative for the metal HAPs.

Case 3 – Softwood lumber mill

- 233 MMBtu/hr, spreader stoker, hog fuel

- Currently appears not able to meet or uncertain whether can do so:

    - 0.005 TEQ ng/dscm @ 7% O2 for Tetrachlorinated Dioxins/Furans

    - 0.039 lb/MMBtu heat input limit for filterable Particulate Matter

- Highly uncertain estimated capital cost of $1 million for D/F control (either combustion controls or activated carbon injection with high annual operating costs)

- Estimated capital cost of $3.4 million for PM control (replace existing ESP)

Case 4 –Softwood lumber mill

- 110 MMBtu/hr, spreader stoker, hog fuel

- Currently appears not able to meet or uncertain whether can do so:

    - 490 ppm @ 3%O2 (eq. to 0.39 lb/MMBtu heat input) limit for Carbon Monoxide

    - 0.005 TEQ ng/dscm @ 7% O2 for Tetrachlorinated Dioxins/Furans

    - 0.039 lb/MMBtu heat input limit for filterable Particulate Matter

- Estimated capital cost of $2.1 million for CO control (either overfire air or CO catalyst, and CEMS for O2); uncertain if additional control for D/F will also be necessary.

- Estimated capital cost of $3.1 million for PM control (addition of ESP and Continuous Opacity Monitor (COM))

- This mill was ready to meet the original Boiler MACT health-based compliance alternative for the metal HAPs.

**11. An Eastern Paper Mill**

<u>Uncertainty Over the Ultimate Carbon Monoxide Limits Frustrates Planning</u>.

Two combination coal and wood fired boilers are equipped with over-fired and undergrate air systems for NOx and carbon monoxide control. It is believed that these

units can comply with the carbon monoxide limits for biomass without significant changes to the air systems.

In light of the expected reconsideration and that unit designations is one of the primary topics, the company is unable to decide whether additional controls will be required for these two units. If the unit designations changed under reconsideration, then it is likely that the emission limits also would change. This could result in wasted capital should the standards become less stringent. However, the worse case is in the event that the standards are made more stringent due to actions taken under reconsideration. Without a stay of the effective date of the rule, then the company will be faced with irreparable harm due to insufficient time to engineer and implement control strategies for units that presently would not require significant upgrades. In essence, without a stay to the rule, these units would not be allotted the full three years to comply as all other units regulated by Boiler MACT would have.

**12. Southeastern Wood Furniture Manufacturer**

The Furniture Industry Faces Multiple Layers of Uncertainty.

At its main facility, the company operates multiple boilers rated at greater than 10 million BTU/hr. Like most facilities in the wood furniture industry, the company's boilers are fired with a traditional fuel mix consisting of kiln-dried wood "off fall" that includes wood with resin-based adhesives. The company must first determine whether the fuel is a solid waste under the NHSM rule. Although the company believes that the fuel is not a solid waste, the final outcome and the corresponding timeline for such a determination are uncertain. Until this determination is finalized, it will be difficult for the company to make strategic decisions on how to meet its energy needs. The difficulty faced by the company will be amplified by the uncertainty of EPA's upcoming reconsideration process. In other words, even if the company determines that the fuel mix is not a solid waste (and the company is, therefore, subject to Boiler MACT standards for existing major sources), the company will be unsure of its compliance obligations until EPA completes the reconsideration process.

EPA Should Issue a Stay to Provide Sufficient Time for Compliance and Prevent the Wasteful Expenditure of Resources.

In determining how it will proceed toward compliance within the three-year period prescribed by the Boiler MACT, the company must contact equipment suppliers and determine whether boiler modifications such as the installation of emission control devices will be needed. Because natural gas is not available near the company's main facility, fuel switching is not an option. While the company's strategy must address the full suite of standards in the Boiler MACT rule, the company is particularly concerned that additional emission controls would be needed to comply with the solid fuel emission standard for particulate matter (PM) and, possibly, the dioxins/furans (D/F) standard for biomass boilers. Before an emission control device could be made operational, the following tasks must be completed: the evaluation of control technology options,

engineering design, vendor selection, approval of capital expenditures, construction, and startup testing.

If all of the Boiler MACT requirements were known, boiler upgrades could easily take over two years, without any time included for needed permit changes. Because the final Boiler MACT requirements will remain unknown until EPA completes reconsideration, the lack of a definitive standard will present the company with the impossible task of aiming towards a moving target. In the absence of a stay, the company's attempts to achieve compliance could result in installation of equipment which is not capable of providing the requisite level of control, or it could result in unnecessary expenditures for unneeded controls.

Concerns With Global Competitiveness and Equity Favor The Issuance of a Stay During Reconsideration.

In a business which is trying to provide jobs to American workers and is already struggling to survive under the depressed economy, the company cannot afford to make ill-advised decisions and expenditures. Even before the recent economic downturn, many plants in the casegoods furniture industry were closed due to foreign competition. The boilers in most of these plants are standing idle, thus resulting in large decreases in emissions from the furniture industry. Many other industries have suffered the same consequences. All of these prior reductions should be considered before forcing the company to proceed with compliance with a rule that could change as a result of reconsideration. EPA should issue a stay of the Boiler MACT so that the rule can be finalized before the company must dedicate scarce resources towards compliance.