YELLOW PINE ENERGY COMPANY, LLC
PSD PERMIT APPLICATION 17700 (9/28/07)
RESPONSE TO DNR-EPD AIR PROTECTION BRANCH LETTER OF JUNE 17, 2008

1. Comment Regarding Timeframe.

Yellow Pine and its shareholders are alarmed at the timing indicated in our June 4th meeting for a draft permit in five months (November 2008), which would imply a final permit could not be received until January 2009. Previously, we understood from DNR's staff that our permit work was being progressed to achieve the draft permit by mid-July. The draft BACT table we were provided in May, even if "unofficial" represented progress, which now seems to be slipping away. In hind-sight, the issues raised in DNR's June 17th letter could have been addressed months ago in our three previous submittals (November 30, 2007, January 10, 2008 and April 16, 2008) and Yellow Pine hopes that this correspondence will satisfy all remaining information needs.

As noted several times in our discussions with DNR staff, Yellow Pine's contracts to supply electricity are at risk of termination for lack of an air permit by a date certain and have very substantial monetary damages for delay. These contracts are key to the success of the project. The air permit is on the "critical path" and therefore, affects Yellow Pine's ability to adhere to a schedule. While the Air Protection Branch staff may have received permission from Ms. Abrams to put aside Yellow Pine's permit work in favor of other applications, that was not communicated to us prior to our June 4th meeting. We are now faced with trying to get relief from said damages and/or the loss of these contracts, which represents years of work and substantial investment by Yellow Pine.

Summit Energy represents shareholders, who were encouraged to invest in Georgia by the State's renewable energy incentive programs, including the Governor's February 28, 2006 Executive Order to expedite permitting of renewable energy projects. Yet in the case of Yellow Pine's permit, it has been put aside, key personnel assigned to Yellow Pine's permit (Ms. Keith) was let go and we learned in the June 4th meeting that evaluation of our air model had not even begun, now 10 months after submittal of the application! Months before the submittal, we briefed DNR's staff, including the air modeling personnel. As discussed below, a way forward is to finalize the realm of outcomes proscribed by regulation, which are consistent with the project's scope. Without a doubt, the application is complete. Yellow Pine asks to receive the benefit of the Governor's Executive Order so that this renewable energy plant's permit is expedited. Please advise as to your expected timing once you have had a chance to review this letter.

2. B&W BFB References.

Babcock and Wilcox ("B&W") is cited in the June 17th letter in respect of certain representations about BFBs. These representations are not valid for Yellow Pine as discussed below.

B&W declined to submit a proposal into Yellow Pine's solicitation for boilers conducted earlier this year. The reasons given were that they did not manufacture a wood-fired BFB unit of the size Yellow Pine needed, and they could not meet the emission limits indicated in Yellow Pine's permit application, without the use of catalysts, which B&W said would not be economic for the project. In short, they did not offer Yellow Pine a BFB boiler (nor vendor data). B&W may be applicable for a smaller unit, but it is not useful for Yellow Pine. Given the foregoing, it does not make sense for Yellow Pine to base its permit on their technology.

B&W's references arise in the June 17th comments about supplemental fuels and "dusty" catalyst systems. Yellow Pine feels the use of supplemental fuels is "Good Utility Practices" given the far larger size of Yellow Pine's BFB (see discussion below). The State of Georgia is not guaranteeing that Yellow Pine will never have a safety issue if supplemental fuels are not used. Yellow Pine understands the disadvantages of using supplemental fuels, but it is not prudent to eliminate them.

In respect of "dusty" catalyst systems, Yellow Pine documented another BFB manufacturer (Metso Power), that its experience with a biomass BFB "dusty" SCR was unsuccessful (see copy of e-mail in Appendix A), and reverted to a SNCR. Yellow Pine cannot be turned into a catalyst R&D project. B&W declined to submit a proposal to Yellow Pine, and therefore, one cannot substantiate their "marketing brochure" statements. Note that Plant Carl isn't placing its proposed oxidation catalyst in the "dusty" section of it pollution control train. There is no further documentation the Yellow Pine can offer. Therefore, it is reasonable for Yellow Pine to conclude that "dusty" catalyst systems are not technically feasible.

3. Catalyst Systems Clarification.

To be clear, at no time did Yellow Pine state it was not concerned about plugging of an catalyst system, contrary to your statement in the first paragraph of page 7 of the June 17th letter. At DNR's request, Yellow Pine previously investigated a SCR catalyst system at the "back-end" (i.e after the bag house) to avoid plugging/fouling/non-performance. As demonstrated in the BACT analysis for this configuration, the cost of reheating the flue gas to allow a catalyst system to function was cost prohibitive. Yellow Pine is in agreement with DNR on this finding. Yellow Pine also agrees that such a design also has adverse energy and environmental impacts (see YP's April 18, 2008 correspondence); this was neither a new issue nor a new position on catalyst systems.

4. "Back-end" Oxidation Catalyst Systems, Other Configurations.

The June 17th letter cites Plant Carl as having shown a "back-end" oxidation catalyst system is technically feasible. Yellow Pine's additional research discussed below reconfirms that such a system is not technically feasible and casts doubt on if Plant Carl's system will work based on vendor data from a major oxidation catalyst company, Johnson Matthey Inc.

Plant Carl's decision to propose a "back-end" oxidation catalyst appears not to have been driven by BACT or MACT analysis, but by their decision not to file for a PSD permit, and thereafter, the realization that they may not be able to stay under the PSD limit for CO. Based on our investigation, the temperature of Yellow Pine's flue gas (306 degrees F – Metso Power vendor data) is too low relative to the temperature required for reaction (500 to 700 degrees F – Johnson Matthey vendor data). The project owner did not return our phone calls; their environmental consultant said he was following the project manager's direction and said he did not independently verify that an oxidation catalyst would work.

The oxidation catalyst vendor Summit Energy contacted on behalf of Yellow Pine, Johnson Matthey Inc., confirmed that a dust-free environment is needed and stated that the catalyst would be poisoned by the elements in biomass flue gas, thereby deactivating it (see copy of e-mail attached in Appendix A). The Johnson Matthey web site documents extensive oxidation catalyst experience in gas-fired power generation, refinery gas clean-up and automotive applications, but none in biomass power generation. Therefore, it is reasonable for Yellow Pine to reconfirm that an oxidation catalyst is not technically feasible.

Putting aside the lack of technical feasibility for the moment, based on the earlier work on the "back-end" SCR, reheating of the flue gas is not economic in a BACT assessment and also has adverse energy (fossil fuel use) and environmental (additional emissions) impacts. Therefore, it is reasonable to conclude that such "back-end" systems would not be viable under BACT in any event.

The Metso Power's vendor data shows that there is no "hot side" of the flue gas exiting a BFB because the exit temperature is only 306 degrees F and the flue gas temperature is reduced further as it goes through the scrubber and bag house. We are not aware of any BFB manufacturer who has an ESP in the hot zone between the superheater and the economizer/air heaters. Therefore, there is no prospect for a "hot side" ESP. To summarize, the "back-end" oxidation catalyst and other possible configurations are not technically feasible. Even if they were, the BACT analysis shows they are not viable economically and have additional adverse consequences. Therefore, it is reasonable to conclude that Yellow Pine's emissions of CO (and as a proxy for VOC and organic HAPs) can best be controlled by good combustion controls. Please see the discussion below and in Appendix B (Boiler MACT) on CO, VOC and organic HAPs as to permit levels.

5. Commercially Available Fuels.

The June 17th letter requests consideration of biofuel/non-fossil fuel, as the only supplemental and start-up fuels to be used by Yellow Pine. It is a worthy goal of a renewable energy company to use renewable resources. However, it is not reasonable for Yellow Pine to base its permit on fuels, which are not commercially available in the Fort Gaines area in the quantities Yellow Pine needs. BACT considerations should not cause fundamental changes in the project scope, which are not commercially supported. The following discusses what fuels are available and proffers revised specifications for supplemental fuels.

At present, Biodiesel is not commercially available in the Fort Gaines, Georgia area. Summit Energy's investigation of fuel oil dealers, GEFA and suppliers indicate that Yellow Pine would have to special order such fuel at a premium price and hope its order could get filled, given its projected use. One vendor in nearby Cuthbert, Georgia (Whatley Oil) commented that it had tried to market biodiesel on a small volume of 5% of Yellow Pine's annual need. However, the vendor discontinued its effort and is not offering the product because the biodiesel separated in his storage tank, fouling it, and was priced at a premium of about 25% to regular diesel and customers refused this pricing. Therefore, it is reasonable for Yellow Pine to conclude that biodiesel is not sufficiently available at reasonable cost to base it permit on only this fuel for its boiler start-up and engines.

It may be that other parties have submitted permit applications to manufacture such fuel, or that Plant Carl says it will use this fuel if it in fact breaks ground, but that does not cross over the fact that biodiesel is not commercially available today in the Fort Gaines area and Yellow Pine has no assurances that it will be commercially available, in sufficient quantity and on economic terms in the future. The State of Georgia is not guaranteeing to make this fuel commercially available in the Fort Gaines region. Therefore, it is not viable for Yellow Pine to base its permit on only biodiesel for boiler start-up, auxiliary boiler and diesel engine fuel.

There is a wide range of coals commercially available from mines in Alabama and elsewhere. In Yellow Pine's application, the maximum sulfur specification for bituminous coal was 5% by weight regardless of source; perhaps this was misunderstood. Two varieties of petroleum coke are commercially available which vary by sulfur specification: U.S. Gulf Coast (4.5% sulfur) and Caribbean (6% sulfur).

Presently, the type of TDF commercially available in the region is a chopped tire, which still includes the wire. This type of TDF can be used in stoker (traveling grate) boilers as the wire falls onto the grate, but is not suitable for BFBs, because the wire will fall to the bed floor and block the fluidizing air nozzles, causing an outage prematurely. Although Yellow Pine hopes vendors will modify their product to supply the 95% metal-free TDF variety, no assurances can be given that this refined type of TDF will be commercially available on economic terms and in volumes needed by Yellow Pine in the future. Hence, Yellow Pine's project scope includes three boiler supplemental fuels. While it is a worthy goal to avoid fossil fuels, and perhaps TDF may emerge as the best supplemental fuel over the project's life, Yellow Pine should not be asked to commit to non-commercial requirements for BACT under this permit.

Plant Washington proposed to use 3.12% sulfur Illinois coal (6.14 lb SOx/MMBTU). The Longleaf permit uses different emission limits for a range of coal sulfur contents. A BFB and dry scrubber offer better control efficiency than a scrubber alone, which should give rise to consideration of a wider range of sulfur specification. Additionally, the maximum design input of the supplemental fuels is 15% by hourly BTU input to the boiler (229 MMBTU/hr maximum), which when co-fired with 85% biomass, results in low SOx emissions. Based on the foregoing, Yellow Pine does not agree with the suggestion in the "unofficial" BACT table to use only low sulfur compliance coal, especially when the same standard isn't being applied to others. It is reasonable to allow a range of sulfur contents and fuel types and set emission limits accordingly (see SOx table).

Yellow Pine is in a large forestry district and therefore, most of its biomass fuel will come from timber harvesting residuals. Depending on the time of year and species, the time the waste material laid on wet ground, rainfall during transport and other factors, the moisture content of wood waste will vary. Timber harvesting firms do not dry the wood waste; it is prepared and delivered in "as is" condition. Drying biomass prior to firing is inefficient with no assurance that CO emissions would improve. Metso Power advised that CO emissions are best managed by boiler combustion controls. We are not aware of any FB boiler manufacturer who requires or recommends pre-drying biomass for CO, VOC or Organic HAP emission control. Therefore, it is not reasonable to limit the specification of biomass to 40% moisture content as was indicated in the "unofficial" BACT table and Yellow Pine submits that no biomass moisture content specification is needed. Note that the CO emissions proposed by Yellow Pine are consistent with the proposed Plant Carl emission factors, even though Plant Carl's design fuel HHV is significantly higher (5,500 BTU/lb HHV) than Yellow Pine's (4,350 BTU/lb HHV).

5. BACT – Clean Fuels for BFB.

(i) Size and Scale-up Factors. Specifically to Yellow Pine, it will incorporate one of the largest wood waste-fired BFB boiler(s) in the world. It is an issue of scale-up and large size which gives rise to including supplemental fuels in Yellow Pine's scope. In order to operate within the design parameters, there must be sufficient net energy (net of vaporizing water in the fuel) to maintain a steady start-up and continuous operation across the large cross section of the bed. It is the combination of reaction of gasifying the wood waste, vaporization of water to steam and the bottom air feed, which provides the uplift to suspend the bed material. Above the bed, the now gasified fuel combusts in a minimal oxygen environment, which provides maximum conversion efficiency and minimal emissions, especially thermal NOx.

In a BFB, this is a delicate balance in order to maintain the bed in the proper zone of the boiler and to obtain good combustion control. The use of a supplemental solid fuel can immediately provide a calorific injection to counteract inadequate gasification energy. Increasing the air flow may lift the bed, but at a cost of consuming more energy from the bed, and if taken too far, will push through an area of the bed, blow material out of the bed and cause a forced outage. Adding more biomass will further tax the gasification energy requirement. Dry biomass, if available, would only constitute 45% to 74% of the energy input capability of the supplemental fuels and does not offer the localized heat intensity. The safety issue arises in that an unstable bed may no longer uniformly fluidize, become too dense, trapping a steam pocket, and then erupt. Loss of control of a boiler's combustion poses a significant risk to the plant's operators, contrary to "Good Utility Practice" and the only solution is to shut down, with resulting sizable monetary penalties under Yellow Pine's power sales contracts for unscheduled outage. Yellow Pine does not wish to become an experimental proving ground on the safe operation of a large-scale biomass BFB by eliminating the supplemental fuels.

It would be highly irregular for an air permitting authority to dictate an unsafe operation of the applicant's plant. Yellow Pine understands that supplemental fuels are more costly to use than biomass, and their use can have minor negative consequences on environmental impacts, which is why Yellow Pine plans to use these fuels sparingly. Yet it is imprudent to prohibit the use of supplemental fuels if that is what the applicant feels is necessary for safety.

(ii) Plant Carl. See comment above; plant Carl would have a boiler cross section less than one fourth of Yellow Pine and has a higher calorific fuel (chicken litter, which is dry wood) as a norm.

(iii) B&W. See comments in item 2 above. Ideally during normal operations, supplemental fuels would not be used.

(iv) Non-fossil supplemental fuels. TDF is a non-fossil solid supplemental fuel requested in the application; please refer to EPA documentation, which confirms that TDF is not a fossil fuel. As noted in item 5 above, the type of TDF required for a FB is not presently commercially available to Yellow Pine, as a result, Yellow Pine selected three supplemental fuels; please see additional discussion on this topic under item 13 (Applicability of 40 CFR 60 Da).

Note that the Clay County zoning approval prohibits the use of chicken feces/litter or renderings, so those higher calorific fuels cannot be used. Yellow Pine is not zoned to process tires into TDF to make this type of fuel itself. See item 5 above regarding biodiesel for start-up fuel. Diesel and propane are used only during boiler start-up, prior to the synchronization of the generator to the grid, i.e. before any electricity is generated (see vendor diagram in Appendix A).

(v) Handling/Storage of Biomass. See item 5 above; handling/storage of wood waste to protect the biomass from rainfall is already contemplated (see the fugitive dust emission section of the permit for covered storage areas), but would not achieve the same effectiveness as the supplemental fuels for boiler control. Note that the Georgia Forestry Commission advised that there is no appreciable amount of dry lumber scraps in the area as the sawmills and pulp mills consume all of their wood waste. Therefore, a reliable dry wood resource is not within the project's fuel supply scope.

(vi) TDF – Sulfur Content. Summit Energy re-checked the specification for 95% metal-free TDF with the vendor, who is a supplier in New York State (Innovative Waste Recovery, Inc.); this vendor provided its laboratory testing result of 1.82% sulfur and 16,110 BTU/lb (as received), 1.84% S and 16,310 BTU/lb (dry); the lab test report is attached in Appendix A. Also, the EPA website reported samples "prepared by WRI" (party not identified), which reported 1.23% S (as received), 1.24% S (dry). We therefore stand corrected that the sulfur content of 95% metal-free TDF has an expected average sulfur content of 1.5% and a maximum of 2.0% sulfur @ 16,100 BTU/lb (2.485 lb SOx/MMBTU uncontrolled). The SOx emission table below uses this data.

(vii) Coal and Pet.Coke Sulfur Specification. As noted in item 5 above, the maximum coal sulfur specification in the application was 5% @ 10,500 BTU/lb (or 9.52 lb SO2/MMBTU uncontrolled emissions). Coal with this sulfur content is available from Alabama, Central and Northern Appalachian and the Illinois basins. Yellow Pine does not expect to use Powder River Basin coals as its requirement is to small to support unit train shipments and Yellow Pine's site is not accessible by rail in any event. The maximum sulfur Pet.Coke is the Caribbean variety of 6.5% and 14,100 BTU/lb (or 9.22 lb SO2/MMBTU uncontrolled). Both of these specifications were consistent with JEA's Northside CFB project, which taps the same fuel markets as Yellow Pine.

These are maximum specifications, and no doubt, lesser sulfur content varieties are commercially available at higher cost, generally doubling in cost ($/MMBTU) between the highest and lowest quality fuel. On a delivered basis, the spread between 1% sulfur and 3.7 % sulfur coal is approximately $2.30/MMBTU (delivered). Based on a combined BFB-scrubber control efficiency of 91%, the difference in emissions is 0.45 lb SOx/MMBTU (7 lbs SOx/MMBTU – 2 lbs SOx/MMBTU x (1 – 91%) = 0.45 lb SOx/MMBTU). Dividing the cost differential by the SOx impact yields $10,222/ton cost ($2.30/.45 x 2000 lb/ton = $10,222/ton of SOx). This metric indicates that use of compliance coal is cost prohibitive. Further, coal prices have increased very substantially (i.e. greater than 50%) during 2008 indicating that this cost may increase by the time the plant goes into operation.

From a BACT perspective, it is not just a matter of technical feasibility, but a reasonable range for fuel specifications within the project's scope and taking into account costs and control efficiency. In the Longleaf permit, a range of fuel sulfur specifications were permitted with related emission levels, rather than only the lowest sulfur content coal. Based on the foregoing BACT assessments, project scope and commercial availability, Yellow Pine proposes the following revised specifications for supplemental fuels:

> Yellow Pine proposes to limit the maximum sulfur content of coal to 7.0 lbs SO2/MMBTU (uncontrolled), to use the U.S. Gulf Coast variety of Petroleum Coke (4.5% S or 6.38 lbs SO2/MMBTU uncontrolled) and 95% metal-free TDF with a maximum of 2% sulfur or (6.4 lbs SO2/MMBTU uncontrolled), with a maximum design and permit limit of 15% of the hourly BTU input to the boiler (229.35 MMBTU/hr) made up of such supplemental fuels.

Please see the following section incorporating this data, which provides an engineering assessment of these revised supplemental fuel specifications.

6. BACT - SO2 (and Sulfuric Acid Mist) from BFB – Revised for Fuel Specifications.

The formula below is used to transform uncontrolled emissions into controlled emissions for SO2:

Uncontrolled

(% sulfur/lb fuel) x (2 lbmole SO2/lbmole sulfur) x (1 lb fuel/BTU content)x1 MM = lb SO2/MMBTU

Uncontrolled Biomass: 0.002 x 2 / 4,350 x 1 MM = 0.920 lb SO2/MMBTU

Uncontrolled Coal: 0.0368 x 2 / 10,500 x 1 MM = 7.00 lb SO2/MMBTU

Uncontrolled Pet.Coke: 0.0450 x 2 / 14,100 x 1 MM = 6.38 lb SO2/MMBTU

Uncontrolled TDF: 0.0200 x 2 / 16,100 x 1 MM = 2.48 lb SO2/MMBTU

85/15 Bio/Coal: .85 x .92 + .15 x 7.00 = 1.832 lb SO2/MMBTU

85/15 Bio/Pet.Coke: .85 x .92 + .15 x 6.38 = 1.739 lb SO2/MMBTU

85/15 Bio/TDF: .85 x .92 + .15 x 2.48 = 1.154 lb SO2/MMBTU

100% Biomass: 1.00 x .092 = 0.920 lb SO2/MMBTU

Controlled

Uncontrolled lb SO2/MMBTU x (1 - % BFB efficiency) x (1 - % scrubber removal efficiency)

Note that when firing on 100% biomass, a sand bed is used because the calcium carbonate in wood ash adsorbs sulfur. For the fuel mixes, limestone is added to the bed as a function of the fuel mix's sulfur content and the scrubber provides additional sulfur removal. The table below shows the control efficiencies for each of the four scenarios (85/15 Bio/Supplemental and 100% biomass) using the revised supplemental fuel specifications at steady state operation (i.e. 30-day average):

Fuel Mix	Uncontrolled Lb SO2/MMBTU	BFB Efficiency	Scrubber Efficiency	Combined Efficiency	Controlled Lb SO2/MMBTU	Proposed BACT Limit Lb SO2/MMBTU
Bio/Coal	1.832	30%	91%	93.70%	0.1154	0.115
Bio/PetCoke	1.739	30%	91%	93.70%	0.1096	0.110
Bio/TDF	1.154	30%	91%	93.70%	0.0727	0.074
Biomass	0.920	30%	91%	93.70%	0.0579	0.060

The biomass sulfur content is the maximum combined sulfur content (0.02% or 0.092 lb SOx/MMBTU uncontrolled) for a wide variety of tree species (NCASI[1] – less than 0.02% sulfur), bark (NCASI – 0.01% to 0.134%, EPA – 0.05% to 0.75%), stumps/roots, peanut hulls, cotton stalks, switchgrass (0.16% sulfur) and pecan shells all of which are present in southwest Georgia, with timber harvesting residuals being the largest component. A data sheet was previously provided for other biomass types. The NCASI study cautions: "The properties of wood residues and bark fuels can vary so greatly that a standard specification is not possible. The differences should be recognized and accounted for in the engineering and operation of wood-fueled [boiler] systems." Accordingly, it is reasonable for Yellow Pine to use 0.092 lb/MMBTU SO2 (uncontrolled) as the basis for its biomass fuel specification and to request a limit with a small margin for variances (3.5%) or 0.060 lb SO2/MMBTU versus the engineering calculation of 0.579.

[1] National Council of the Paper Industry for Air and Stream Improvement, Technical Bulletin No. 96, "Information on the Sulfur Content of Bark and Its Contribution to SO2 Emissions when burned as Fuel", August 1978.

Yellow Pine requests a short-term limit of 0.19 lb SOx/MMBTU – 3 hour average, for variation in control efficiency, which may occur when supplemental fuels are suddenly charged into the boiler as discussed above. Such a change in fuel input will require an adjustment to the stoichiometric ratio of calcium carbonate to sulfur, which will require the plant operators to monitor the fuel inputs, the boiler operation, scrubber operation and the CEMS data to react. This higher short-term limit is logical in support of this operation practice.

The source data for BFB efficiency and scrubber efficiency are from Metso Power (combined SOx control efficiency). The scrubber efficiency is comparable to published data for dry scrubbers on a variety of solid fuels. Yellow Pine confirms that the above vendor data, engineering calculations and fuel specifications support the BACT limits shown in the above table based on BFB combustion controls, limestone use during the bio/supplemental mix firing and dry scrubber.

Yellow Pine does not agree with DNR's suggestion in the "unofficial" BACT table indicating 97% [combined] control efficiency, as that level is not technically feasible for a BFB-scrubber system. The coal-fired plants noted in the June 17th letter are using CFB technology, which has a significantly higher boiler control efficiency, which impacts the combined control efficiency. This is the case in the Deseret project, where a 50% boiler control efficiency and a 90% scrubber control efficiency would predict a reduction of 1.1 lb SO/MMBTU to 0.055 lb/MMBTU (95% combined control efficiency). JEA's Northside CFB and ADM's CFB have somewhat lower combined control efficiencies indicated in their permits. A CFB achieves much greater mixing due to its higher air flow rate, recirculation through the cyclone and reaction time for sulfur capture by calcium carbonate, and therefore, better control efficiency. A BFB is a much more static bed with no cyclone recycle, resulting in less boiler mixing/reaction time and significantly lower control efficiency (30%).

The above limits can be translated from lb/MMBTU to lb/MWHr by a factor of 1,529 MMBUT/hr over 125 MWs (gross generator electrical output) (e.g. 0.115 lb/MMBTU x 1,529/125 = 1.4 lb SO2/MWHr). Yellow Pine requests adopting the above noted fuel specifications and limits corresponding to the uncontrolled and controlled levels (30-day average) shown in the above table as BACT based on BFB combustion controls, limestone injection for the when firing bio/supplemental fuel mixes and dry scrubber controls and a short-term (3-hour average) limit of 0.19 lb SO2/MMBTU as monitored fuel testing and CEMS and operating in accordance with Good Utility Practice.

<u>7. Revised Wet Scrubber BACT Estimate.</u>

We hereby revise Yellow Pine's Wet Scrubber BACT Estimate because to implement this option, Yellow Pine would have to construct a larger water treatment plant and wastewater treatment plant to provide for the incremental water use. This infrastructure cost was not in the original calculation. The total installed cost of incremental water plant is estimated to be $5.5 million. Also, the cost of the scrubber plant has risen approximately 10% since the original estimate was prepared, or an increase of $3.9 million. These changes increase the Total Installed Cost by $9.4 million; all other figures and references are unchanged. The revised total annualized cost is therefore $10.99 million, divided by 670 total tons of SOx removed = $16,403/ton.

There are no assurances that the additional water use or waste-water discharge will be approved by DNR, and there are the other negative impacts noted in the permit application. Waste water discharge from a wet scrubber system contains very significant total suspended solids (TSS) and soluble solids. Despite pre-treatment, there are no assurances that DNR would permit higher TSS loading. It is reasonable for Yellow Pine to conclude that a wet scrubber is not justified under BACT (cost prohibitive) and the related adverse impacts on the river may prohibit this approach in any event.

<u>8. BACT – PM10 from BFB.</u>

To clarify, the PM limits in Yellow Pine's application were total PM of 0.033 lb/MMBTU, not the filterable sub-set. The Metso Power vendor data for filterable PM is 0.015 lb/MMBTU on 100% biomass at steady state operation. Yellow Pine does not expect the mix-fuel cases to yield a different result. The filterable amount is in the range of MACT figures provided by DNR. Uncontrolled PM is not easily translated from the MMBTU input. Further, there is a collective effect of the combined controls of good combustion controls, dry scrubber and fabric filter bag house which are difficult to separate.

Public comments made in Pennsylvania in connection with PA-EPA permitting of waste coal-fired CFBs, its CAMR and DOE/NETL's Phase II Mercury Control Technology Field Testing Program, dated May 2007, indicate that there is greater capture of mercury by the presence of chlorine. Biomass is a source of chlorine. As a result, co-firing biomass with supplemental fuels is a MACT operating practice which is related to PM control (See Appendix B (Boiler MACT)) as PM is used as a surrogate for metallic HAPs.

Yellow Pine requests the below limits as BACT based on good combustion controls, dry scrubber and fabric filter bag house, with stack testing for demonstration of control efficiency and opacity monitoring (at steady state):

Filterable PM	0.015 lb/MMBTU
Total PM	0.030 lb/MMBTU

9. BACT – Feasibility of Oxidation Catalyst for CO.

As noted in item 4 above, we were unable to substantiate how Plant Carl will make an oxidation catalyst work. Their permit engineer could not confirm that the oxidation catalyst is technically feasible. Further, a major oxidation catalyst vendor, Johnson Matthey, advised that the flue gas will poison the catalyst (see correspondence attached in Appendix A). This additional research substantiates the statement made in Yellow Pine's application that an oxidation catalyst is not technically feasible. As a result, no further analysis was performed.

Note that if the economics of the "back-end" SCR were used to derive the costs, hypothetically, the CO/VOC/Organic HAPs were somehow isolated from the flue gas and assuming a 50% reduction in CO (670 tons/year), then the cost of removal would be approximately $220,000/ton.

Yellow Pine again submits that good combustion controls for CO are representative of BACT in this application. Further, additional vendor data from Metso Power shows that for 100% biomass, short-term CO emissions (3 hours) may be as high as 0.30 lb CO/MMBTU and long-term average (30 days) shall not exceed 0.149 lb/MMBTU. Yellow Pine therefore requests the following CO emission limits as BACT, based on the use of good combustion controls and a CEMS for CO to monitor compliance.

CO – 3 hour average	0.300 lb/MMBTU
CO – 30-day average	0.149 lb/MMBTU

Related to CO is VOC as a BFB combusts fuel by first gasification and then combustion with minimal air to achieve maximum efficiency. This operating regime gives rise to CO, VOCs and organic HAPs as a result of incomplete combustion of all the fuel. Yellow Pine does not agree with the suggested "unofficial" BACT table of a VOC limit of .003 lb/MMBTU and does not understand how this amount was derived, assuming good combustion control. Metso Power vendor data for VOCs at 100% biomass are shown in the table below:

VOC – 3 hour average – 100% Biomass	0.025 lb/MMBTU
VOC – 30-day average – 100% Biomass	0.020 lb/MMBTU

Yellow pine requests these revised limits as BACT based on the use of good combustion controls. Yellow Pine proposes to use a CO CEMS as a proxy for VOC compliance. The table bellow shows the proposed VOC limits for the 85/15 Bio/Supplemental Fuel mixes:

VOC – 3 hour average – Bio/Supl.	0.023 lb/MMBTU
VOC – 30-day average – Bio/Supl	0.018 lb/MMBTU

10. BACT – Feasibility for SCR for NOx.

Please see the comment in items 2 and 3 above. We agree with DNR that the reheating requirement for a "back-end" catalyst system is cost prohibitive and there are negative consequences for additional fuel consumption and emissions.

No additional scenarios are technically feasible, and therefore, no additional calculations were performed. Note that the cost of diesel fuel used in the earlier analysis is significantly higher today. Regardless of the supervisory labor treatment, one would reasonably draw the same BACT conclusion that a back-end SCR system is cost prohibitive.

11. BACT – NOx for BFB.

There is a fundamental difference between a BFB and CFB in terms of SNCR performance (control efficiency). A CFB uses as cyclone, which is in the high temperature zone and provides additional time and mixing for the ammonia to react. Also, the air velocity through a CFB is approximately twice the rate as in a BFB, which also improves the CFB's performance to about 75% control. A BFB does not have a cyclone and operates at lower air velocity/mixing, and as a result, does not have as good a SNCR control efficiency (56%). Please see the boiler cross section diagrams comparing the two types of FB boilers in Appendix A. The Deseret, Big Cajun, JEA and AMD plants are all CFBs plants. Their BACT NOx limits are based on the better control efficiency afforded by a CFB and their NSPS limits incorporate the significantly higher steam cycle efficiency (BTU/KWHr), given that as coal has only about 10% of the moisture content of biomass. The Metso Power's BFB vendor data is 0.10 lb/MMBTU based on a SNCR and 100% biomass. Metso Power advised that the supplemental fuels contain a greater proportion of fuel-bound nitrogen than biomass and therefore are rated at a higher uncontrolled emission. The table below summarizes the uncontrolled/controlled NOx emissions by fuel type and mix at steady-state conditions.

Fuel or Fuel Mix	Uncontrolled Emission Factor lb NOx/Ton	as lb/MMBTU	BFB SNCR Control Efficiency as %	Controlled NOX Emissions lb/MMBTU	Proposed NOx Emission Limit lb/MMBTU
Biomass	2.00	0.230			
Coal	15.20	0.724			
Pet Coke	21.00	0.745			
TDF	6.00	0.186			
Bio/Coal	3.98	0.304	56.50%	0.132	0.135
Bio/PetCoke	4.85	0.307	56.50%	0.134	0.135
Bio/TDF	2.60	0.223	56.50%	0.097	0.100
100% Bio	2.00	0.230	56.50%	0.100	0.100

The source for uncontrolled emission factors for biomass, coal and pet.coke were from EIIP Document, pages 14- A2 to A3 for a CFB; TDF data was estimated by the ratio of nitrogen in TDF versus biomass (.24/.18 = 1.3, 1.3 x 2.0 lb NOx/ton = 2.6 lb/ton). Yellow Pine used this data because uncontrolled NOx is derived from fuel-bound nitrogen and thermal conversion of nitrogen in the combustion air. Fuel ratios were used to calculate the blended NOx uncontrolled emissions as CFBs and BFBs operate in a similar temperature range. The source data for SNCR control efficiency in a BFB is from Metso Power, based on a 15 ppmv ammonia slip.

Yellow Pine requests the above noted NOx emission limits by fuel mix as BACT based on good combustion controls and a SNCR with a 15 ppmv ammonia slip and as monitored by the fuel mix and its BTU content and NOx CEMS for compliance.

12. BACT – Mercury from BFB.

The cost of activated carbon injection (ACI) is substantially greater than $10,000/ton, and instead is in the millions of dollars per ton as discussed below and is therefore cost prohibitive for this application. A review of DOE/NETL's Phase II Mercury Control Technology Field Testing Program, dated May 2007, indicates that based on the comparably sized 79 MW Lee Station Unit 1 operating on 100% bituminous coal with a mercury content of 3.35 lb Hg/TBTU, the test result was a 50% Hg reduction at a cost in 2006 dollars of $71,400 per pound Hg removed ($143 million per ton) without byproduct costs and $179,000/lb ($358 million per ton) Hg removed including by-product costs. Based on a 40% escalation in power plant costs since 2006 reported by Cambridge Energy Associates and *The Wall Street Journal*, these figures today would be approximately $99,960 per pound of Hg ($199 million/ton) and $250,600 per pound of Hg removed ($501 million/ton) respectively. Note that this study comments that the cost per pound of Hg removal is so high because of the low uncontrolled mercury content, which is the case for Yellow Pine. Yellow Pine did not find any examples of biomass FB plants using ACI. This report validates Yellow Pine's comment that ACI is cost prohibitive.

An adverse environmental impact of using ACI is that most ACI manufactured in the U.S. is produced from coal, and an increase in ACI use will cause more coal firing to produce ACI and related emissions. R&D papers indicate that perhaps amended silicates will be developed to replace ACI, but at present, this idea is still in research, and therefore, not a BACT alternative (not technically feasible).

In respect to the baseline data for mercury content in fuels, Yellow Pine used AP-42 data (biomass, coal) and California Air Resources Board data for PetCoke and US EPA Office of Research and Development, Air Emissions from Scrap Tire Combustion (EPA-600.R-97-115, October 1997) for TDF; an 85/15 average for the fuel mixes was then derived. The other data sets for biomass did not measure mercury content. Summit Energy obtained a Pet.Coke analysis from another boiler manufacturer, Alstom SA, who reported test data for samples purchased by Florida utilities. The Alstom data reported 3 samples were tested for mercury and showed a range of 0.03 ug/g to 0.05 ug/g (2.1 to 3.5 lb Hg/TBTU), albeit not intended to be a correct statistical study for mercury levels as the other 14 samples were not tested for mercury. This sampling of mercury content in Pet.Coke is much less than the California Air Resources Board data of 44 lb Hg/TBTU. It may be that the California Air Resources Board used Pet.Coke samples from California refineries, and perhaps the crude oil used in these refineries (principally Alaskan crude) has a higher mercury content, which in turn, increases the mercury content. In any event, initial stack testing correlated to fuel analysis, emission tests and temperature readings can resolve the issue. Coal can vary for mercury type within the broad group of central and northern Appalachian coals and Illinois basin coals. As a result, Yellow Pine used the AP-42 emission factors noted in the footnotes of Appendix E of the application. Note that the AP-42 Factor (3.95 lb Hg/TBTU) is similar to the specifications of the Lee Station 1 (3.35 lb Hg/TBTU) in the DOE/NREL Study referenced above. The controlled Hg emission is based on a 90% combined control efficiency of a dry scrubber or Inorganic HAP/acid gasses and 90% fabric filter control efficiency for TSM.

Yellow Pine does not agree with the 99.93% mercury control efficiency noted in DNR's "unofficial" BACT table ($1 - 2.16 \times 10^{-7} / 3.30 \times 10^{-4} = 0.9993$ or 99.93%). Because a portion of the uncontrolled mercury emissions will not condense into particulate, it is not appropriate to use the PM control efficiency of the fabric filter to estimate controlled Hg emissions. Yellow Pine does not understand what DNR's estimate of mercury content in biomass is in order to arrive at 0.216 lb Hg/TBTU versus the AP-42 data times control efficiency, and why the emission level is not tied to fuel input. Yellow Pine requests DNR revisit this area.

Using the AP-42 data and 90% control efficiency, Yellow Pine requests the mercury emission limits as stated on page 6-35 of Yellow Pine's application as BACT, which are based on good combustion controls, co-firing supplemental fuels with biomass (biomass provides chlorine to the flue gas which enhances particulate capture of mercury), dry scrubber and fabric filter baghouse. Please see Appendix B for the MACT assessment.

13. Applicability of 40 CFR 60, Subpart Da.

Yellow Pine requests that DNR reconsider its statement that "Yellow Pine … would be classified as a fossil fuel-fired electric steam generating unit under 40 CFR 60, Subpart Da." Yellow Pine does not meet the thresholds for that categorization. Quoting from that regulation:

> **§ 60.40Da Applicability and designation of affected facility.**
>
> (a) The affected facility to which this subpart applies is each electric utility steam generating unit:
>
> (1) That is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel);

The maximum design input capability of fossil fuel into Yellow Pine's boiler is 229 MMBTU/hour (in this case, fired in combination with biomass), which is less than the threshold limit of 250 MMBTU/hr. Supplemental fuels are 15% of the BTU input and therefore, the associated gross and net plant output would be 18.75 MWs and 16.50 MW respectively (15% of 125 MW gross, 110 MW net plant output), which are less than the 73 MW threshold. Yellow Pine does not meet these thresholds to be classified as a fossil fuel-fired electric generating unit.

Note that the Metso Power data show that no start-up fossil fuel is to be used for electricity generation as the start-up burners shut down prior to the turbine-generator's synchronization to the grid (i.e. prior to generating any electricity – see start-up diagram in Appendix A).

This design limit is a fundamental requirement of Yellow Pine's scope. If too much high calorific supplemental fuel is introduced into the boiler, the enthalpy of reaction per cubic foot of the boiler will increase faster than the boiler is capable of removing the heat via steam flows, leading to a temperature rise and over-pressure of the steam tubes and creating a safety risk for explosion. The boiler design is determined principally to burn biomass in a steam balance with the turbine generator. The design has limited flexibility to increase its ability to remove heat from the boiler into the steam cycle and has only a 5% steam over-pressure allowance. Therefore, the 15% maximum BTU/hr input for supplemental fuels must not be exceeded for safety reasons. Therefore, Yellow Pine asks DNR to reconsider its statement, as this rule does not appear to be applicable. Yellow Pine suggests this design limit be stated in the permit conditions for the avoidance of doubt.

Yellow Pine does not understand the comment in part 5 of this topic in the June 17th letter, which states that "We [DNR] believe you [Yellow Pine] would avoid being subject to NSPS Subpart Da altogether if you [Yellow Pine] committed to burning only non-fossil fuels in the boiler." While this statement is true, the statement does not seem to recognize the 250 MMBTU/hr threshold.

Applicability (or not) of this rule has wide-ranging implications as noted in the other statements made in the June 17th letter, such as the biofuels/TDF only, emission standards and CEMS requirements. Yellow Pine would appreciate if DNR can explain its statements vis-à-vis the above stated thresholds.

14. Acid Rain Permit Application.

Yellow Pine understands DNR's suggestion to file its Acid Rain permit application to be able to consolidate the hearing on the air permit and the acid rain permit into one. Therefore, Yellow Pine will submit its acid rain permit application in coordination with the air permit if one is required following from item 13 above.

15. BACT – Clean Fuels for Auxiliary Boilers and Stationary Engines.

Please see item 5 above.

16. Applicability of 40 CFR 63, Subpart B.

As noted in Yellow Pine's correspondence of November 30, 2007, DNR staff advised that a HAP MACT for the BFB was not required.

Notwithstanding the February 8, 2008 ruling in respect of coal and oil-fired EGUs, which may not be applicable to Yellow Pine as noted in item 13 above, Yellow Pine would at least fall under the Boiler MACT standards for large industrial and commercial steam generating units. Please see Appendix B for a MACT analysis for HAPs.

Appendix A

Data References

A-1 Metso Power e-mail re: failure of "dusty" section SCR.

A-2 Metso Power vendor data for 100% Biomass Case.

A-3 Johnson Matthey Inc. e-mail re: oxidation catalyst, poisoning.

A-4 TDF sample test results provided by Innovative Waste Management / Buffalo Fuels and EPA.

A-5 Pages/Exhibits from DOE/NREL Phase II Mercury Control Technology Field Testing dated May 2007

A-6 CFB and BFB cross-section diagrams, location of SNCR.

A-7 BFB start-up cycle showing shut-off of start-up burners prior to turbine-generator synchronization.

From: Robert Deneault, MetsoPower
Sent: 03/28/2008 05:24 PM EDT
To: mark.sajer@sep-llc.com
Cc: Kerry Flick; Rick Cashatt
Subject: SCR Technology on a CFB

For the Metso Power CFB and BFB product line SNCR is overwhelmingly the NOx control technology of choice. However, we have OEM experience with both SNCR and SCR technology. Since the early 1980's, we have contracted 60 CFB and 160 BFB boilers for the global market. Of those, only one was supplied with SCR technology for NOx control.

The lone CFB unit where the SCR was installed for NOx control is located in Sweden at Norrkopping Energi AB (pronounced Noor-shopping). Steaming capacity is 333,000 pph at 1600 psi and 1000F steam temperature. The unit was delivered in 1993 and is designed to fire Bituminous Coal, TDF and wood waste. The SCR is located in the second pass after the economizer, but before the air heater and dust removal equipment. This location in chosen as this is where the gas temperature window is correct to ensure that proper catalytic reactions occur to reduce NOx emissions in the presence of Ammonia. However, with the high maintenance cost associated with the SCR, and the need to have the catalyst washed off-line repeatedly due to flue gas poisoning from the biomass/TDF fuels, the Owner has since elected to remove the SCR from service and now utilizes only SNCR technology for NOx control. The use of the SNCR has produced similar deNox results to the previously employed SCR without the lost downtime and excessive maintenance costs. The poisoning of the catalyst at this plant is believed to be primarily due to the high alkali content from the biomass firing. Should the unit have fired coal alone (based on published data from a DOE Cooperative Agreement on NOx control on CFB and PC units), this may still be an issue due the nature of a CFB to exhibit high flue gas concentrations of $CaSO_4$; another known poisoning mechanism for vanadium pentoxide-based catalyst.

For the Yellow Pine project, firing all wood, we believe the proven technology to be a single BFB with SNCR and it will be the lowest life-cycle cost with NOx guaranteed around 0.10 #/MMBtu (depending on fuel-born nitrogen content).

Regards,

Bob Deneault

GM, Capital Sales
Metso Power

A-2

Metso Power BFB Vendor Data Sheet
For 100% Biomass

Summit Energy Partners, LLC
Yellow Pine Project - Fort Gaines, GA
New Biomass/Fossil Fuel Fired BFB Boiler Project

2E. PREDICTED PERFORMANCE

The predicted performance table below is provided for information only and is **not** considered as part of any overall guarantees.

Load	**% MCR**	**100**
Fuel mixture	**a.r**	**Wood Waste**
Water and Steam		**At Boiler Header**
Feedwater temperature	°F	430
Live steam pressure after boiler	psig	1520
Live steam temperature after boiler	°F	1005
Live steam flow	lb/hr	930,000
Continuous blowdown	lb/hr	13,950
Air and Flue Gas		
SA in (at FGAH inlet)	°F	155
PA in (at FGAH inlet)	°F	155
Flue gas flow	lb/hr (wet)	1,579,500
Flue gas O2 content (dry)	vol-%	3.8
Emissions (7% O2 dry @ 32°F)		
SO_2	lb/MMBtu	0.06
NOx (with SNCR)	lb/MMBtu	0.10
CO	lb/MMBtu	<0.15
HCl	lb/MMBtu	0.022
Particulate (filterable only)	lb/MMBtu	0.015
VOC	lb/MMBtu	0.02
Ammonia Slip	ppmv	15
Boiler exit temperature	°F	306

Print Message

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From: Jeremy Harris <harrisje@jmusa.com>
ate: 2008/07/21 Mon PM 12:34:09 GMT
To: mark.sajer@sep-llc.com
Subject: Re: Re: Oxidation Catalyst for Biomass-fired power plant

Mark,

All of the compounds listed below are catalyst poisons.

Lead: .0035 ug/m3 , .00275 lb/hr
Flourides: .00028 ug/m3
Mercury: .00147 lb/hr
Biomass Ash/Flue Gas: K, Na, Ca, CaO, P, Si, As, Pb, Zinc, Mn
HCL: 6.67 lb/hr

Best regards,
Jeremy Harris
for Johnson Matthey
Phone: 484-320-2122
Cell: 610-636-8318
Fa[illegible] 484-320-2152

>>> <mark.sajer@sep-llc.com> 7/18/2008 1:18 PM >>>
Jeremy,

Would you please identify which compounds are poisionous by highlighting from the specification list - that would tell us what to try and eliminate.
Thank you,

Mark

From: Jeremy Harris <harrisje@jmusa.com>
Date: Thu Jul 17 09:45:49 CDT 2008
To: Mark Sajer <mark.sajer@sep-llc.com>
Cc: Wilson Chu <CHUW@jmusa.com>
Subject: Re: Oxidation Catalyst for Biomass-fired power plant

Mark,

This does not appear to be a good application for catalyst. All of the elements and compounds that y[illegible]ave listed are catalyst poisons. If these elements and compounds come in contact with the

Mr. James A. Capp
Process Industries & Gas Turbines
Johnson Matthey Inc.
400 Lapp Road
Malvern, PA 19355 USA
Contact: Jeremy Harris
Tel: +1 484 320 2122
Fax:+1 484 320 2152
Email: info@jmssec.com

7/11/08

Dear Mr. Harris,

I obtained your contact information from your company's web site. We wish to investigate your company's oxidation catalyst system for reduction of CO, VOCs and organic HAPs from the flue gas of a biomass-fired power plant. The plant may also use up to 15% by BTU input 95% metal-free tire-derived fuel from time to time.

The technical specification of the flue gas are as follows:

Flue Gas Flow Rate: 9,332 cu.ft./sec @ 286 degrees F exiting the scrubber/baghouse
CO emission: 459 lb/hr
VOC emission: 30.58 lb/hr
Organic HAP emission: ammonia (15 ppmvd), benzene, formaldehyde, hexane, etc. 0.03 lb/hr
Lead: .0035 ug/m3 , .00275 lb/hr
Flourides: .00028 ug/m3
Mercury: .00147 lb/hr
Biomass Ash/Flue Gas: K, Na, Ca, CaO, P, Si, As, Pb, Zinc, Mn
HCL: 6.67 lb/hr

From reading information on your web site, we have assumed that the catalyst would need to be placed after the scrubber/baghouse in order to prevent particulates from fouling the catalyst. Is this correct, or can the catalyst be placed into a "dirty" section of the boiler? What flue gas temperature is required for the catalyst to work? Does the heat of oxidation provide the necessary temperature increase, or must there be an external heat source to bring the flue gas up to temperature in order to cause the reaction to occur?
What is the expected minimum abatement of CO, VOC and organic HAPs?
What is the budget estimate for the system?

Below is my contact information.
Thank you,

Mark Sajer
Managing Director

Note – Appendices A-4 to A-7 were not scanned.

Appendix B
Case-by-case MACT Analysis
Yellow Pine Energy Company, LLC

Executive Summary

Under 40 CFR 63, Subpart A, Part 63 National Emission Standard for Hazardous Air Pollutants, case-by-case Maximum Available Control Technology (MACT), Section 112(g)(2)(B) of the Clean Air Act Amendments of 1990, Yellow Pine will be a new source with predicted emissions greater than 10 tons per year of any individual Hazardous Air Pollutant ("HAP") or 25 tons per year of any combination of HAPs. Accordingly, this Case-by-Case MACT Analysis is presented herein.

Yellow Pine undertook a survey of similar fluidized bed, biomass-fired or biomass-supplemental co-fired plants and performed additional evaluation as noted herein. Where noted below, the control and emission level determined under BACT are more stringent. Yellow Pine proposes to comply with the above-noted regulations by (i) co-firing supplemental fuels with biomass (a chlorine source which enhances mercury capture); (ii) good combustion controls; (iii) SNCR, (iv) dry scrubber with limestone injection, (v) fabric filter bag house, (vi) the operating procedure of temperature measurement of fabric filter/stack exit, as a surrogate for TSM/Hg condensibles and (vii) the operating procedure to utilize quality control of waste wood as described herein. The table below summarizes the HAPs and controlled limits proposed for BACT and per this MACT analysis.

AP Category	Uncontrolled Emissions (tpy)	Controlled Emissions (tpy)	Proposed BACT / PSD Application	MACT Assessment	Control and Compliance Determination Method
Mercury					Co-firing with biomass, SNCR, dry scrubber, fabric filter / Stack & Temperature testing
100% Biomass	.0234 tpy .0000035 lb/MMBTU		.0023 tpy, .00000035 lb/MMBTU	0.000003 lb/MMBTU	As above
85/15 Bio/Coal	.0239 tpy .00000357 lb/MMBUT		.0024 tpy, .00000036 lb/MMBTU	0.000003 lb/MMBTU	As above
85/15 Bio/PetCoke	.0644 tpy .00000962 lb/MMBTU	.0064 tpy maximum	.0064 tpy, .000000096 lb/MMBTU	0.000003 lb/MMBTU	As above
85/15 Bio/TDF	.0206 tpy .00000308 lb/MMBTU		.0021 tpy, .00000031 lb/MMBTU	0.000003 lb/MMBTU	As above
Non-Mercury Total Selected Metals – as PM	115 tpy	11.5 tpy	0.015 lb PM /MMBTU (filterable) 0.030 PM lb/MMBTU (total)	0.025 lb/MMBTU	As above
Organic HAPs – as CO	91.8 tpy	91.8 tpy	0.149 lb CO/MMBTU	0.149 lb CO/MMBTU	Good combustion controls / fuel wood quality control CO CEMS
Acid Gases – HCL	1,272 tpy	127.2 tpy	n/a	0.019 lb HCl /MMBTU	Dry scrubber / Stack Testing
Total	1,478 tpy	231 tpy			

1. MACT Determination Process.

40 CFR 63.43 sets forth the following two principles to be used in the establishment of MACT emission limitations in a case-by-case MACT determination"

> "The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority."
>
> "Based upon available information, the MACT emission limitation and control technology recommended by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

Yellow Pine undertook a survey of similar fluidized bed, biomass-fired or biomass-supplemental co-fired plants and performed additional evaluation as noted herein. The biomass-fired FB units studied are of older vintage and there are several proposed biomass-fired FB units which were evaluated (Plainfield Renewable Energy, Plant Carl). There are coal with biomass co-firing CFB units in operation (ADM) and proposed (Dominion – Virginia City, Wellington Development – Green Energy Resource Recovery Project).

In February 2002, EPA issued "Guidelines for MACT Determinations under Section 112(j) Requirements". These guidelines offer a step-by-step process for making a MACT determination consistent with the above two principles. The process can be summarized as follows:

> Step 1 – Identify the MACT-affected emissions unit (the Fluidized Bed Boiler)
> Step 2 – Make a MACT floor finding
> Step 3 – List all available/reasonable applicable control technologies
> Step 4 – Eliminate technically infeasible control technologies
> Step 5 – Determine efficiency of applicable control technologies
> Step 6 – Identify the maximum emission reduction control technology
> Step 7 – Conduct an impact analysis
> Step 8 – Establish the MACT emission limitation

This eight-step process is used in this permit application to make a case-by-case MACT determination for the proposed Facility. The only source of HAPs is the Fluidized Bed Boiler(s).

2. Assessment of Comparable Units, MACT Floor.

Mercury emissions related to the fluidized bed boiler(s). Several units were studied and other MACT filings to investigate a MACT floor. There are no operating FB boilers combusting primarily biomass which have add-on controls specifically for mercury. In these cases, HAP/Hg control is achieved through the use of good combustion controls, co-firing with chlorine-containing fuels, and co-controls of scrubbers for SOx and particulate (PM) control. Thus, the MACT floor for biomass is removal based on co-controls, scrubbers and particulate control devices. Two proposed biomass units are Plainfield Renewable Energy and Plant Carl.

Plainfield Renewable Energy's CFB's mercury limit is 3.0 E-6 lb Hg/MMBTU, HCl of 0.00436 lb HCl/MMBTU and a maximum of 10 tons/year mercury or 25 tons/year combined for all HAPs, based on co-controls of a dry scrubber and fabric filter, with compliance determined by CEMs for NOx, SOx and CO and annual performance analysis, either by fuel analysis and/or stack testing. The initial stack test requires fuel testing to compare input concentrations to stack emission rate. The spray dryer is rated at 90% control efficiency for SOx, HCl and metals and the Fabric Filter is rated 99% for PM and 90% for

TSM metals. Although this plant is not a major HAP source and is subject to NSPS 40CFR60 Subpart Db, it is a very recent permit and noteworthy for its operating procedure with respect to fuel wood qualities, to address that plant's sizable expected use of wood waste from C&D materials, being located in Connecticut. Excluded material from wood waste are: treated wood (pesticide/rot treatments and creosote), plastics, plaster, wall board, asbestos and asphalt shingles. This plant is to be located in an area of Connecticut, which more urban/suburban and where the supply of C&D materials is much greater than southwest Georgia. Georgia's Green-e accreditation standard also excludes pesticide/rot/creosote/chromated copper arsenate containing wood wastes other than trace amounts of less than 1% of the total wood fuel utilized. Wood waste quality control noted above is technically feasible an a useful means to protect against unwanted HAP sources; such an "operating rule" is useful under MACT.

Public Service of New Hampshire's Plant Schiller repowering project is a 50 MW CFB fired on biomass and coal. Its mercury limit is 3 E-06 lbs/MMBTU based on 6 lb Hg/TBTU fuel input; the HCl limit is 0.02 lb/MMBTU. The controls are good combustion controls, limestone injection into the bed SNCR and fabric filter (no scrubber). The mercury control is rated at 50%.

Plant Carl proposes a BFB, which will be a major HAP source and a case-by-case MACT was determined and is subject to NSPS 40CFR60 Subpart Db. HAPs will be controlled by good combustion practices, oxidation catalyst, dry scrubber and ESP, where CO emissions (0.149 lb/MMBTU) are the surrogate for organic HAPs and PM is the surrogate for TSM/Hg with a PM limit of 0.025lb/MMBTU and TSM sublimit of 0.0003 lb/MMBTU. Note that there is no reduction stated for VOC or organic HAPs due to the oxidation catalyst and no control stated for acrolein. HCl will be controlled by good combustion practices and the scrubber (0.02 lb/MMBTU) with a combined control efficiency (based on uncontrolled versus controlled tons/year) of approximately 92%. Plant Carl's mercury limit is 0.000003 lb Hg/MMBTU, with an implied 50% reduction between uncontrolled and controlled tons/year. Monitoring will be by CEMS for NOx, SOx and CO and opacity COO and stack testing for Hg, TSM and HCl. The opacity limit is 20% with 27% for one 6-minute period. Each of these limits and compliance measures were based on a case-by-case MACT determination for a new large solid fuel boiler. There are no noted operating procedures. Note that Yellow Pine's investigations into oxidation catalysts concludes that an oxidation catalyst will become poisoned and the flue gas lacks a sufficient temperature for reaction, and therefore, is not technically feasible. The other controls are technically feasible and mirror Plainfield Renewable Energy's controls.

To widen the scope of review, Yellow Pine also reviewed CFBs, which are predominantly fired by coal with some biomass usage and are subject to NSPS rules 40CFR60 Subpart Da. ADM's Columbus 2006 permit for CFBs use coal and up to 20% biomass, PetCoke and TDF. ADM-Columbus's CFB units use a CFB with limestone, SNCR and fabric filter, but no scrubber. There is no permit limit for mercury.

A 300 MW proposed plant by Wellington Development – Green Energy Resource Recovery Project is a CFB which proposes to fire waste coal and about 15% bituminous coal. The unit will use good combustion controls, limestone injection into the bed, SNCR, dry scrubber and fabric filter. Compliance will be monitored by CEMS for NOx, SOx and opacity (COO) and stack testing. This unit is noteworthy as it was subject to extensive mercury investigation as the State of Pennsylvania was deliberating its own CAMR. The unit is also noteworthy for an operating practice to measure the stack exit temperature, on the theory that if the exit temperature is below a certain reading, HAP TSM metals and Hg will condense and be captured by the fabric filter. In other word, by monitioring fabric filter / stack temperature, the reasoning was that it is a surrogate control. Green Energy is subject to MACT standards of 1.1 E-6 lb Hg/MWHr for waste coal and 6.0 lb Hg/MWHr, and based on an 85/15 mix, the result is 1.835 E-6 lb Hg/MWHr based on a maximum Hg content of 0.26 ppm and 90% control efficiency from the fabric filter and stack temperature monitoring. Another similar waste-coal/coal fired CFB plant (River Hill, PA) uses a Hg formula using the same emission factors. As indicated in vendor data, Yellow Pine's flue gas temperature entering the scrubber/fabric filter system is expected to be 306 degrees F, which is about the temperature point at which condensation of Hg/TSMs will occur. Temperature monitoring (thermocouple) is technically feasible. Therefore, using temperature measurement is useful under MACT as an operating proceedure; its also indicates good boiler efficiency at steady state. Note that this method is not effective during start-up, shut down or short term variations.

A proposed 668 MW CFB plant by Dominion Resources, the Virginia City Hybrid Energy Center, is a large 2 x 334 MW CFB plant using waste coal, coal and biomass. This permit was subject to a case-by-case MACT determination and NSPS 40CFR60 Subpart Da. The controls proposed are good combustion practice, limestone injection into the bed, SNCR, dry scrubber, fabric filter and activated carbon injection ("ACI"). It is presumed that the use of ACI was driven by the large size of the facility (668 MWs) and its high uncontrolled Hg emissions from its coal/waste coal specification. The combined mercury controls are rated at 98% removal based on an average coal mercury content of 0.351 ppmw (29.3 lb Hg/TBTU @ 12,000 BTU/lb coal) and a maximum content of 0.51 ppmw and 49.46 pounds Hg per year. Assuming the scrubber-fabric filter combination yields a 90% Hg control efficiency, then the ACI is designed for 80% additional reduction. Compliance monitoring will be by CEMS for NOx, SOx, CO and Hg and COM (opacity).

Note that Dominion's mercury content specification is 3 to 8 times as great as Yellow Pine's specifications. Also note that according to the DOE/NREL's Phase II Mercury Control Technology Field Testing Program, dated March 2007, that "additional research, development and demonstration activities are required before it [ACI] is considered a commercial technology. Accordingly, Yellow Pine concludes that ACI is not yet technically feasible, and Dominion is saying it will undertake to demonstrate ACI with its plant when it goes into operation. Also note that from a BACT perspective for Dominion's coal mercury specification, ACI has far better BACT economics. The DOE/NREL's Phase II Mercury Control Technology Field Testing Program, table 9 indicates a cost of $13,400/$47,000 per lb Hg removed (without and with byproduct costs) for an 8.23 lb/MMBTU coal mercury content. Using a ratio of 8.23/29.3 to reflect uncontrolled Hg emissions, would indicate a $3,764/$13,200 per lb Hg removal in 2006 dollars.

Based on the foregoing, the MACT floor has been established to be based on good combustion controls, co-firing with chlorine-containing fuels, and co-controls of scrubbers for SOx and particulate (PM) control. Yellow Pine evaluates the operating rules and ACI below.

3. Potential Control Options.

Potential control strategies and technologies were evaluated for the following HAP subcategories:

a. Inorganic HAPs, including acid gases (HCl) – wet or dry scrubbers

b. Metal HAPs (TSM) – particulate control devices – fabric filter or ESP and waste wood wood specifications prohibiting pesticide/rot/creosote/arsenated copper chromate less than 1% by weight of the total fuel input to the Fluidized Bed Boiler(s).

c. Mercury (Hg) – combination of scrubber, particulate control (fabric filter), an evaluation of ACI, bag house/stack exit temperature monitoring

d. Organic HAP – good combustion controls and CO monitoring.

Note that an oxidation catalyst for Organic HAPs was not included due to Yellow Pine's investigation showing that such technology is not technically feasible.

The operating procedure regarding wood waste to exclude certain contaminants is viable. Therefore, it is feasible to limit wood contaminants to less than 1% by weight per year.

The operating procedure regarding exit gas temperature monitoring is viable, and acts as a surrogate for CEMS for mercury. Yellow Pine's BACT analysis shows very low mercury emissions due to the fuel specifications of low mercury content and co-controls achieving 90% mercury reduction. Because Yellow Pine's fossil fuel input is limited to 229 MMBTU/hr (versus the 40CFR60 Subpart Da threshold of 250 MMBTU/hr fossil fuels), a mercury CEMS is not required. Therefore, initial stack testing to correlate fuel mercury content to emissions and stack exit temperature monitoring are a viable means to enhance mercury emission co-control.

4. Technology Evaluation, Impact Analysis.

Good combustion control and the co-controls of a dry scrubber and fabric filter are feasible and economic. According to the DOE/NREL report, ACI is not yet technically feasible for mercury and has cost and adverse environmental considerations, which are further evaluated below.

Yellow Pine's uncontrolled emissions for mercury are 1/10th those of the proposed Dominion CFB units and less than Plant Schiller and the proposed Plants Carl and Plainfield. Yellow Pine's controlled emissions based on BACT co-controls are 1/10th of the vacated Boiler MACT. Yellow Pine's proposed BACT-based emissions equal or are less than the vacated Boiler MACT limits:

Boiler MACT	Yellow Pine BACT
PM / TSM : 0.025 lb/MMBTU PM, 0.0003 lb/MMBTU TSM	0.015 lb/MMBTU – filterable PM,
HCl – 0.02 lb/MMBTU	0.019 lb/MMBTU (90% dry scrubber control efficiency)
Hg – 3.0 E-06 lb/MMBTU	3.57 E-07 lb/MMBTU
CO – 0.149 lb/MMBTU	0.149 lb/MMBTU

The very low concentrations of mercury result in very high removal costs, estimated to be $199 million/ton without byproduct costs and $501 million/ton including byproduct costs based on cost determined in the DOE/NREL Phase II Mercury Control Technology Field Testing Program, based on the evaluation of ACI on a low-mercury coal and a 50% reduction in mercury.

An adverse environmental impact of using ACI is that most ACI manufactured in the U.S. is produced from coal, and an increase in ACI use will cause more coal firing to produce ACI and related emissions. R&D papers indicate that perhaps amended silicates will be developed to replace ACI, but at present, this idea is still in research, and therefore, not a MACT alternative (not technically feasible).

Based on its proposed controls, Yellow Pine achieves a greater mercury control efficiency than Plainfield or Plant Carl (90% for Yellow Pine, 50% for Plant Carl, 50% for Plant Schiller), an emission limit about half that of Dominion's Virginia City Plant (0.00000357 lb/MMBTU for Yellow Pine versus 0.00000965 lb/MMBTU for Virginia City). Yellow Pine's annual limit of 4.7 lb Hg/year is less than 10 percent (10%) of Virginia City's annual limit (49.46 lb Hg /year).

Therefore, Yellow Pine's emission limit for mercury is a more stringent result using good combustion practices, co-firing biomass with supplemental fuels when used, dry scrubber, fabric filter and an exit temperature (at steady state) less than 300 degrees F than the emission limit achieved by Virginia City's co-controls with ACI. As a result, the use of ACI for mercury control is not considered to be viable as an add-on control for MACT for Yellow Pine.

For TSM, co-controls of a scrubber-fabric filter at a 90% control efficiency, with compliance via PM monitoring as a surrogate and stack testing to initially correlate fuel input to stack testing and temperature control, are selected for MACT. This finding is consistent with the above-noted plants with the addition of the temperature monitoring operating procedure.

For Organic HAPs, good combustion controls, with compliance by CO emissions and CO CEMS monitoring is selected for MACT. This finding is consistent with the above-noted plants with the addition of the wood waste quality control operating proceedure.

For Inorganic HAPs (acid gases), good combustion controls and dry scrubber, with 90% control efficiency, monitored by stack testing is selected for MACT. This finding is consistent with the above-noted plants.

The Case-by-Case MACT for HAP analysis is summarized below page along with the proposed BACT limits. The resulting controls reduce total HAPs from 1,478 tons/year to 231 tons/year.

5. MACT Emission Limitations.

The table below summarizes the proposed MACT limits by HAP subcategory:

AP Category	Uncontrolled Emissions (tpy)	Controlled Emissions (tpy)	Proposed BACT / PSD Application	MACT Assessment	Control and Compliance Determination Method
Mercury					Co-firing with biomass, SNCR, dry scrubber, fabric filter / Stack & temperature testing
100% Biomass	.0234 tpy .0000035 lb/MMBTU		.0023 tpy, .00000035 lb/MMBTU	0.000003 lb/MMBTU	As above
85/15 Bio/Coal	.0239 tpy .00000357 lb/MMBUT		.0024 tpy, .00000036 lb/MMBTU	0.000003 lb/MMBTU	As above
85/15 Bio/PetCoke	.0644 tpy .00000962 lb/MMBTU	.0064 tpy	.0064 tpy, .000000096 lb/MMBTU	0.000003 lb/MMBTU	As above
85/15 Bio/TDF	.0206 tpy .00000308 lb/MMBTU		.0021 tpy, .00000031 lb/MMBTU	0.000003 lb/MMBTU	As above
Non-Mercury Total Selected Metals – as PM	115 tpy	11.5 tpy	0.015 lb/MMBTU (filterable) 0.030 lb/MMBTU (total)	0.025 lb/MMBTU	As above
Organic HAPs – as CO	91.8 tpy	91.8 tpy	0.149 lb CO/MMBTU	0.149 lb/MMBTU	Good combustion controls, wood waste quality control / CO CEMS
Acid Gases – HCL	1,272 tpy	127.2 tpy	n/a	0.019 lb/MMBTU	Dry scrubber / Stack Testing
Total	1,478 tpy	231 tpy			