

BEFORE THE ADMINISTRATOR
U.S. ENVIRONMENTAL PROTECTION AGENCY

In the Matter of the Title V Air Operating Permit
and Prevention of Significant Deterioration Permit
for Little Gypsy Unit 3
Solid Fuel Repowering Project
Montz, La.

Activity Nos.: PER20020006; PER20060003
Permit Nos: 2520-00009-V1; PSD-LA-720
LDEQ Agency Interest No.: 687

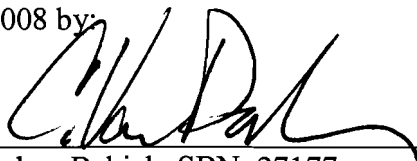
Issued to Entergy Louisiana, LLC
By the Louisiana Department of
Environmental Quality on November
30, 2007.

**PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT
TO THE TITLE V OPERATING AND PREVENTION OF SIGNIFICANT
DETERIORATION PERMITS ISSUED TO ENTERGY, LOUISIANA, LLC FOR THE
LITTLE GYPSY UNIT 3 SOLID FUEL REPOWERING PROJECT IN MONTZ, LA.**

Prepared by:

Emon Mahony, Law Student,
TULANE ENVIRONMENTAL
LAW CLINIC

Respectfully submitted this 9th day of January,
2008 by:



Adam Babich, SBN: 27177
Corinne Van Dalen, SBN: 21175
TULANE ENVIRONMENTAL LAW CLINIC
6329 Freret Street
New Orleans, Louisiana 70118
Phone (504) 865-8814
Fax (504) 862-8721
ababich@tulane.edu; cvandale@tulane.edu
*Counsel for Sierra Club, Louisiana
Environmental Action Network, Gulf Restoration
Network, Alliance for Affordable Energy, and Sal
Giardina, Jr.*

INTRODUCTION

Pursuant to section 505(b) of the Clean Air Act, 42 U.S.C. § 7661d(b)(2) and 40 C.F.R. § 70.8(d), the Sierra Club, Louisiana Environmental Action Network, Gulf Restoration Network, Alliance for Affordable Energy, and Sal Giardina, Jr. (“Petitioners”) petition the Administrator of the U.S. Environmental Protection Agency to object to the Title V Air Operating/Major Modification Permit (no. 2520-00009-V1) and Prevention of Significant Deterioration Permit (no. PSD-LA-720) (collectively, “the Permits”) issued on November 30, 2007 by the Louisiana Department of Environmental Quality to Entergy Louisiana, LLC for Little Gypsy Unit 3 Solid Fuel Repowering Project in Montz, Louisiana. Petitioners ask the Administrator to object to the Permits because they fail to comply with the “applicable requirements” of the Clean Air Act including: Louisiana’s State Implementation Plan (“SIP”), New Source Review and Prevention of Significant Deterioration (“PSD”) permitting requirements, and sections 111, 112 of the Act. *See* 40 C.F.R. § 70.2 (defining “applicable requirement” as used in the Clean Air Act).

Specifically, the Permits violate the Clean Air Act and the “applicable requirements” because: 1. the sulfur dioxide SO₂ emission limits in the PSD Permit for the circulating fluidized bed (“CFB”) boilers do not reflect best available control technology (“BACT”); 2. the Title V Permit improperly allows blanket exemptions from emissions limits during periods of startups, shutdowns, and malfunctions (“SSM”); and 3. the PSD Permit emission limits are based on outdated modeling. Because the Permits fail to comply with applicable requirements of the Clean Air Act, the Administrator must object to the Permits. 42 U.S.C. § 7661d(b); 40 C.F.R. § 70.8(c)(1) (“The Administrator will object to the issuance of any permit determined by the Administrator not to be in compliance with applicable requirements or requirements of [the

CAA].”); 40 C.F.R. § 70.8(d); *N.Y. Pub. Interest Group v. Whitman*, 321 F.3d 316, 333 n.11 (2d Cir. 2002).

LEGAL FRAMEWORK

“The Title V operating permits program is a vehicle for ensuring that existing air quality control requirements are appropriately applied to facility emission units in a single document....Such applicable requirements include the requirement to obtain preconstruction permits that comply with applicable new source review requirements.” *In re Monroe Elec. Generating Plant*, Petition No. 6-99-2 at 2 (EPA Adm’r 1999). Therefore the Administrator must look at whether an emission unit has gone through the proper New Source Review or PSD permitting process, complies with the Louisiana State Implementation Plan (“SIP”), and whether the Title V permit contains accurate “applicable requirements,” including best available control technology (“BACT”) limits. 40 C.F.R. § 70.2; *In re Chevron Prod. Co., Richmond, Cal.*, Petition No. IX-2004-08 at 11-12 n.13 (EPA Adm’r 2005). If the Administrator objects to the Permits, “the Administrator *shall modify, terminate, or revoke*” the Permits. 42 U.S.C. § 7661d(b)(3).

Best Available Control Technology

The CAA forbids the construction of, or modifications to, a major emitting facility unless the facility uses BACT. 42 U.S.C. § 7475(a)(4). The Louisiana SIP specifically requires that major modifications “shall apply best available control technology for each regulated NSR pollutant.” La. Admin. Code tit. 33, § III:509(J)(3).¹ At its core, BACT is an emissions limitation based on an “application of production processes or available methods, systems, and techniques.” La. Admin. Code tit. 33, § III:509(B); *In re Three Mountain Power, LLC*, 10

¹ Louisiana’s EPA approved state implementation plan for PSD is codified at La. Admin. Code tit. 33, § III:509. 40 C.F.R. § 52.986.

E.A.D. 39, 54 (E.A.B. 2001) (“BACT means an emission limitation rather than a particular control technology.”). The goal of a BACT analysis is to reach an emissions limit for each pollutant. The underlying technology or standard is the means to achieve the limits. Only if “the administrative authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible,” may the administrative authority allow a “design, equipment, work practice, operational standard, or combination thereof” to satisfy the BACT requirement instead. *Id.*

EPA’s draft *New Source Review Workshop Manual* (“NSR Manual”) explains the process for determining BACT using the top-down approach. (EPA, Oct. 1990). Although EPA’s NSR Manual is not a binding regulation, the Environmental Appeals Board considers the NSR Manual to be an accurate statement of EPA’s approach to PSD issues. *In re Newmont Nev. Energy Inv. L.L.C. TS Power Plant*, PSD Appeal No. 05-04, 2005 WL 3626598 (E.A.B. 2005). Indeed, the Ninth Circuit has considered the top down approach the expected way to determine BACT. *See Citizens for Clean Air v. EPA*, 959 F.2d 839, 845 (1992). Entergy used the top-down approach as a template for analyzing BACT for its permit application.

The top-down approach consists of five steps: 1. Identify all control technologies; 2. Eliminate technically infeasible options; 3. Rank remaining control technologies by control effectiveness; 4. Evaluate most effective controls and document results; and 5. Select BACT. *See In re Prairie State Generating Co.*, 13 E.A.D. [], PSD Appeal No. 05-05, slip op. at 14-18 (EAB Aug. 24, 2006 (summarizing and describing steps in the top-down BACT analysis); *NSR Manual* at B.6. The CAA only recognizes energy, environmental, and economic impacts as acceptable grounds for rejecting the most stringent technically feasible control alternative. 42 U.S.C. §

7479(3). These impacts are evaluated in Step 4 of the top-down analysis. If the applicant rejects the most stringent alternative, the burden is on the applicant to justify the rejection. *NSR Manual* at B.26-29.² The NSR Manual further clarifies the control alternative rejection process as involving “a demonstration that circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously, or that argue against the transfer of technology or application of new technology.” *Id.* at B.29.

PROCEDURAL FACTS

Entergy submitted a revised permit application on September 5, 2006, replacing its application submitted on August 22, 2002, for a Title V air operating permit and PSD permit for Little Gypsy Unit 3. LDEQ published draft Title V and PSD permits in early May 2007 and invited public comments on the proposed permits through June 18, 2007.³ During the public comment period, EPA Region 6 and U.S. Fish and Wildlife Service Branch of Air Quality submitted comments on the proposed permits to LDEQ.⁴ *See* U.S. F&WLS comments attached as Exh. A. LDEQ responded to EPA’s public comments on November 30, 2007. Also on November 30, 2007, LDEQ issued the final Title V and PSD permits to Entergy. Entergy’s application, EPA Region 6 and U.S. Fish and Wildlife’s comments submitted during the public

² “The applicant is responsible for presenting an evaluation of each impact along with appropriate supporting information....Step 4 validates the suitability of the top control option in the listing for selection as BACT, or provides clear justification why the top candidate is inappropriate as BACT....In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding needs to be fully documented for the public record.” *Id.*

³ The proposed Title V and PSD permits and Entergy’s application materials are available on the LDEQ website at <http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=3759&SearchText=gypsy&startDate=1/1/2005&endDate=12/10/2007&category=>. Entergy supplemented its application on 9-20-07 after the public comment period expired. This addendum, which is attached as Exh. B, changed the annual NOx emission rate for the project.

⁴ In addition, EPA Region 6 submitted supplemental comments to LDEQ on the proposed Title V and PSD permits on 10-12-07.

comment period, LDEQ's responses to those comments, and the Permits form the basis of this Petition.

This Petition is timely since Petitioners are filing it within 60 days following the end of EPA's 45-day review period as required by CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2). *Id.* EPA received LDEQ's proposed Title V and PSD permits on September 26, 2007. *See* <http://yosemite.epa.gov/r6/Apermit.nsf/AirLA?OpenView&Start=1&Count=4000&Expand=1#1>. EPA's 45-day comment period expired on November 10, 2007. The Administrator has 60 days to grant or deny this Petition after Petitioners file it. *Id.* "The Administrator shall issue an objection within [the 60-day] period if the petitioner demonstrates to the Administrator that the permit is not in compliance with the requirements of [the CAA]." 42 U.S.C. § 7661d(b)(2).

SPECIFIC OBJECTIONS

1. LDEQ's BACT Determination for Controlling SO₂ Emissions is Wrong.

The SO₂ emissions from the proposed project will be above PSD significance levels. PSD Permit, Briefing Sheet at 3. Therefore, LDEQ is required to review Entergy's permit application in accordance with PSD regulations and determine whether Entergy's selected emissions control technology for SO₂ qualifies as BACT. Entergy, which analyzed BACT using a "top down" approach, proposed a "circulating fluidized bed technology combined with limestone injection and a flue gas desulfurization scrubber" as BACT for the CFB boilers (EQT 11 and EQT 12), which are the sources of the SO₂ emissions. LDEQ accepted Entergy's BACT proposal and the SO₂ limit of 0.15 lb/MMBtu—a limit reflecting the worst-case sulfur concentration in the fuel source.⁵ PSD-LA-720, Specific Conditions, Max Allowable Emissions Rates for CFB Boilers.

⁵ PSD-LA-720, Specific Conditions, Max Allowable Emissions Rates for CFB Boilers. This permit also has an SO₂ emission rate for the boilers of 0.08 lb/MMBtu when burning "100% Powder River Basin, western bituminous, western subbituminous and international subbituminous coals, or any combination of these coals with less than 1.5 lb/MMBtu (higher heating value) inlet sulfur concentration."

The PSD permit also has an SO₂ emission rate for the boilers of 0.08 lb/MMBtu when burning “100% Powder River Basin (“PRB”), western bituminous, western subbituminous and international subbituminous coals, or any combination of these coals with less than 1.5 lb/MMBtu (higher heating value) inlet sulfur concentration.” *Id.*

The purpose of BACT is not to apply limits lenient enough to cover the worst case scenario. LDEQ is required to apply the most stringent controls unless Entergy demonstrates that it is not technologically feasible or cost effective, or that the control causes unique adverse energy or environmental collateral impacts. NSR Manual at B.24; *Newmont* at 16. Neither LDEQ nor Entergy demonstrates that the lower limits are not feasible for Little Gypsy Unit 3. Therefore, the Administrator must object to the PSD Permit because it contains deficient SO₂ limits for the CFB boilers.

- a. The SO₂ BACT limits of 0.15 lb/MMBtu for petroleum coke and 0.08 lb/MMBtu for PRB coal are not BACT.

There are at least three other CFB boiler permits that contain much lower SO₂ BACT limits. *See e.g.*, Entergy’s Title V/PSD Permit Application at 4-17. BACT is an emission limit based on the maximum degree of reduction that is achievable. Therefore, the SO₂ BACT limit of 0.15 lb/MMBtu for petroleum coke and 0.08 lb/MMBtu for PRB coal are not BACT because lower limits can be achieved at Little Gypsy. The lower SO₂ limits in other CFB permits, AES Puerto Rico, for example, can be achieved at Little Gypsy using either low sulfur fuel and a more efficient scrubber, up to 98% SO₂ control for PRB coal, or using petroleum coke and a more effective SO₂ scrubber, up to 99.9% SO₂ control. The record contains no demonstration that either 0.15 lb/MMBtu or 0.08 lb/MMBtu represent the maximum degree of SO₂ reduction that is achievable, and LDEQ fails to address this fact in its response to EPA Region 6 comments. *See* 11/30/07 LDEQ Ltr, Resp. to Cmmt. 1.

- b. LDEQ Does Not Provide an Adequate Explanation As To Why It Did Not Consider Lower Sulfur Coal and Petroleum Coke Appropriate for Achieving BACT.

“[I]n selecting BACT[, permitting authorities are required] to consider ‘application of production processes and available methods, systems, and techniques, including fuel cleaning, *clean fuels*, or treatment or innovative fuel combustion techniques.’” *In re Spurlock Generating Station*, Permit No. V-06-007, U.S. EPA Pet. No. IV-2006-4 (Aug. 30, 2007) at 37 (“*Spurlock Order*”) (quoting 42 U.S.C. § 7479(3)) (emphasis added). Permitting authorities “must provide a reason for rejecting a specific control technology as BACT based on the applicable criteria in the Clean Air Act and its relevant implementing regulations.” *Spurlock Order* at 30; *Indeck-Elwood, LLC*, 13 E.A.D. [], PSD Appeal No. 03-04, slip op. at 29 (Sept. 27, 2006). “A permit issuer must, therefore, articulate with reasonable clarity the reasons for its conclusions and must adequately document its decision making.” *Id.* Here, LDEQ failed to do this.

Indeed, EPA Region 6 specifically asked LDEQ to justify the 0.15 lb/MMBtu SO₂ as compared to the 0.129 lb/MMBtu SO₂ limit set for the CFB boilers at the Northampton Generating Station (PA DEP Permit No. 48-00021). EPA Region 6 Comments (6/15/07) ¶ 4. In response, LDEQ attributed the higher SO₂ limit in Entergy’s permit to Entergy’s fuel choice (primarily petroleum coke) which has higher sulfur content than the coal waste primarily used at the Northampton plant.⁶ This response is inadequate.

In addition, Entergy argued and LDEQ parroted that limiting the boilers’ ability to burn a variety of fuels to control SO₂ would defeat the purpose of the project, namely to make use of a readily available local fuel supply. The LDEQ cited as authority the *Prairie State* Environmental Appeal Board’s decision. 11/30/07 LDEQ Letter to EPA Region 6 at 3. However, the facility in *Prairie State* is a mine-mouth plant, tethered to an adjacent mine by conveyors. Little Gypsy is

⁶ LDEQ Public Comments Response Summary, Resp. to EPA Comment 4, attached to Title V Permit.

distinguishable as the CFB is not tethered to any particular source of fuel. The record here contains no evidence that there is a common ownership and control issue related to Little Gypsy fuel. Entergy can buy any fuel that allows it to comply with its permit limits, including cleaner petroleum coke and lower sulfur coals. Having offered no valid justification for its decision to eliminate clean fuels based on design, LDEQ must consider clean fuels in the BACT analysis, as plainly stated in the definition of BACT.

The EPA, in fact, remanded a Title V permit to the state agency to show that lower sulfur coal was not an achievable option to limit SO₂ from coal fired CFB boilers. *Spurlock* Order at 29 (granting petition to object in part based on permitting agency's failure to provide adequate explanation for determining that design basis fuel is BACT).⁷ The EPA said: "While permitting authorities have discretion in making the case-by-case technical assessments necessary to determine BACT for a specific source, in exercising that discretion, they must provide a reason for rejecting a specific control technology as BACT based on the applicable criteria in the Clean Air Act and its relevant implementing regulations. *Id.* at 30.

c. Requiring Low Sulfur Fuel Does Not Require a Change in Little Gypsy's Project Design or Purpose.

The amount of sulfur contained in the fuel dictates, to a degree, the amount of SO₂ that the fuel will emit when burned, as Entergy itself noted. Entergy Title V/PSD Permit Application at 4-24. Appropriately, Entergy identified the use of lower sulfur fuel as a control option in its BACT analysis. Entergy, then, summarily dismissed the lower sulfur fuel option from further BACT analysis asserting that limiting the CFB boilers' ability to burn a variety of fuels would

⁷ "In particular, EPA finds that KYDAQ and EKPC have failed to provide a complete justification for excluding low sulfur eastern bituminous coal as BACT for limiting SO₂ emissions from this project. Accordingly, the Administrator grants the petition on the narrow issue of the selection of SO₂ BACT, limits and directs KYDAQ and EKPC to provide a complete analysis to support the selection of the design coal as BACT." *Id.*

“defeat the purpose of this project.” *Id.* at 4-20. Entergy further said that it “is making use of a readily available local fuel supply (petroleum coke) as the primary fuel source” and wants the flexibility to “burn various types of coal as opportunities present themselves.” *Id.*

LDEQ supported Entergy’s conclusion stating “exclusive consideration of lower sulfur fuels as a control technology is not in accord with the project design.” LDEQ Resp. to EPA Region 6 Comments, Nov. 30, 2007 at 3. LDEQ asserted that Entergy’s conclusion is consistent with the Environmental Appeals Board’s decision in *Prairie State* where the EAB found *Prairie State* did not have to consider low-sulfur coal because that would necessarily mean receiving coal from a distant mine not co-located with the plant. *Prairie State* Opinion at 20-23. As discussed above, however, the situation in *Prairie State* is distinct and does not serve as precedent here. In *Prairie State*, the proposed facility is a “mine-mouth” plant co-located at a coal supply (also owned by *Prairie State*) which contains enough coal to supply the plant’s fuel needs—directly by conveyor belt from the mine—for 30 years. The EAB concluded that to “require evaluation of an alternative coal supply ... would constitute a fundamental change to the project.” *Prairie State* Opinion at 20-21. Alternative coal supplies would be “beyond the scope of the project, [which is] a power plant fueled from coal delivered by a conveyor belt from an adjacent dedicated mine.” *Id.* at 23.

Unlike *Prairie State*, Little Gypsy is not intrinsically tied to a specific and dedicated co-located fuel reserve that will fully power the plant for 30 years. Instead of a facility designed *for* a dedicated co-located fuel reserve as in *Prairie State*, Little Gypsy Unit 3’s design is just the opposite. Entergy designed the Little Gypsy project to burn fuel from a variety of sources. PSD Permit, Prelim. Determination Summary at 17-18. It is designed to accommodate fuels from just about anywhere. On October, 19, 2007, during the hearing before the Louisiana Public Service

Commission, Jeffery Heidingsfelder, Entergy's Director of Engineering and Construction-Fossil testified:

[P]etroleum coke has a lot of variability in the industry. We are in an excellent location to receive petroleum coke for various refineries up and down the Mississippi River and the intracostal waterway, as well as from overseas. We have a good location for overseas shipping of fuels into the site. So the variety opens up to the world, basically within the sulfur contents and other constituents in a range that we designed this facility to burn.⁸

Entergy's preference to use high sulfur petroleum coke from unidentified "local sources" does not dictate the project design. If a permittee's preference for high sulfur fuel—or for the flexibility to burn less-expensive fuel—were a valid exception to Congress' definition of BACT to include use of clean fuels, this exception would swallow the rule. In other words, LDEQ's deference to Entergy's choice of fuel unlawfully allows a preference for dirty fuels to trump CAA § 169(3)'s requirement that BACT take into account techniques that include use of "clean fuels." 42 U.S.C. § 7479(3).

Indeed, when reviewing the EAB's decision in *Prairie State*, the Seventh Circuit Court of Appeals said: "The Act is explicit that "clean fuels" is one of the control methods that EPA has to consider." *Sierra Club v. EPA*, 499 F.3d 653, 654 (7th Cir. 2007).⁹ The Seventh Circuit noted that *Prairie State* presents "a borderline case" as to where to draw the line between requiring available control technology and forcing a redesign of the proposed facility. Little Gypsy, on the other hand, is not "a borderline case." It would not be reasonable for EPA to defer to LDEQ's desire to allow Entergy's preference for an unspecified "local" (and comparatively

⁸ In re: Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility, LPSC Docket No. U-30192, 10-19-7, Cross Examination J. Heidingsfelder, 139; 140:1-5, excerpt attached as Exh. C.

⁹ The statutory definition of BACT, found in section 169 of the CAA, requires consideration of clean fuels. 42 U.S.C. § 7479(3) (defining best available control technology). "In deciding what constitutes BACT, the Agency must consider both the cleanliness of the fuel and the use of add-on pollution control devices." *In re: Inter-Power of N.Y.*, 5 E.A.B. 130, 134 (E.A.B. 1994).

dirty) fuel supply to determine BACT. Indeed, the U.S. Constitution's Commerce Clause policy against state restrictions on interstate commerce militates against EPA acceptance of a desire to discriminate against non-local fuel sources as a justification for relaxed emission standards. *Cf. Oregon Waste Systems, Inc. v. Department of Environmental Quality of State of Or.*, 511 U.S. 93, 98 (1994) (“[The Commerce] Clause has long been understood to have a ‘negative’ aspect that denies the States the power unjustifiably to discriminate against or burden the interstate flow of articles of commerce.”).

In short, Little Gypsy is a project designed to burn a variety of solid fuels from a variety of sources. In fact, Entergy chose the Little Gypsy site for its project in part because of “its accessibility to the sources of fuel ... from the Midwestern United States, Gulf Coast, and international suppliers via the Intracoastal Waterway and the Gulf of Mexico.” LDEQ Basis of Decision at 9. As such, Entergy is required to consider low sulfur petroleum coke and coal in this project. Given that the CFB boilers are designed to burn a wide variety of fuels and sulfur content as low as 0.5 %, ¹⁰ it would be inappropriate to eliminate sulfur coals and petroleum coke as technically infeasible in step 2 of the BACT analysis. Had Entergy completed its BACT analysis properly, it would have necessarily evaluated lower sulfur fuels with other pollution control devices and processes that are more protective than its chosen BACT limit.

Significantly, the five lowest SO₂ limits on Entergy's initial list of control alternatives called for use of a combination of some kind of technological control such as dry lime scrubbers, and a fuel

¹⁰ Entergy's Director of Engineering and Construction-Fossil testified that “CFB boilers represent a proven technology that can burn virtually any carbon-based solid fuel efficiently, including all grades of coal, high-ash waste coals, petroleum coke, and bio-mass. The CFB can also accommodate a broad range of sulfur contents, from 0.5 to 8%.” In re: Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility, LPSC Docket No. U-30192, 7-11-7 Direct Test. of Jeffery Heidingsfelder, 11:3-6, excerpt attached as Exh. D.

restriction, such as coal with a maximum fuel sulfur content of 1%. Entergy's Title V/PSD Permit App. at 4-18.

- d. LDEQ's Cost Analysis Is Wrong: Corrected Analysis Shows Low Sulfur Coal is Cost Effective and LDEQ Cannot Eliminate it on Economic Grounds.

LDEQ further argues that even if lower sulfur fuels were considered as a potential BACT control technology, this option is not economically feasible. 11/30/07 LDEQ Ltr to EPA Region 6 at 3. Entergy calculated cost effectiveness in dollars per ton of SO₂ removed (“\$/ton”) using 2006 as-delivered fuel-cost data, adjusted for differences in the amount of limestone that would be required to control SO₂ emissions from each fuel. *Id.* at 4. LDEQ calculated the ratio of the difference in adjusted fuel costs in dollars per million Btus (“\$/MMBtu”) as such:

[Adjusted Fuel Cost for Fuel #1 – Adjusted Fuel Cost for Petroleum Coke] (1)

to the difference in outlet SO₂ emission rates in pounds per million Btus (“lb/MMBtu”)

[Outlet SO₂ Emissions for Petroleum Coke – Outlet SO₂ Emissions for Fuel #1] (2)

According to the LDEQ table, this ratio yields cost effectiveness in dollar per pound SO₂ removed. This value was then converted to dollars per ton by multiplying by 2000 pounds in a ton. A sample calculation of cost effectiveness for switching from petroleum coke to Powder River Basin coal using the Entergy method:

Cost effectiveness = [1.62 – 1.31]/[0.15-0.08] x 2000 = \$8,857/ton (3)

The results of calculations based on Equations (1) and (2) above are reported as “cost-effectiveness (\$/ton SO₂ removed)” in the first inset table on page 4 of LDEQ's 11/30/07 letter responding to EPA Region 6's comments. LDEQ then goes on to argue that these cost effectiveness values, ranging from \$8,855 to \$117,526/ton, are higher than costs being borne by other similar sources, based on SO₂ cost effectiveness values for other similar facilities. *Id.* at 4-5. This argument is not correct.

First, LDEQ claims that clean **fuels** are not cost effective. This requires that the **fuel** sulfur content be used to calculate cost effectiveness, not the controlled, outlet SO₂ as in the Entergy calculations. The denominator of the cost effectiveness calculation, Eq. (2) above, should be **fuel** sulfur content (called “Sulfur Loading” in the Entergy calculations) rather than “outlet SO₂ Emission Rate,” or

$$[\text{Sulfur Loading for Petroleum Coke} - \text{Sulfur Loading for Fuel \#1}](4)$$

Correcting this single fundamental error, the cost effectiveness of switching from petroleum coke to Powder River Basin coal, the example in Equation (4) above, is:

$$\text{Cost effectiveness} = [1.62 - 1.31]/[9.4 - 0.95] \times 2000 = \$73/\text{ton} (5)$$

Thus, when Entergy’s error is corrected, the cost effectiveness of switching from petroleum coke to Powder River Basin coal tumbles from \$8,857/ton to \$73/ton. Similarly, the cost effectiveness of switching from petroleum coke to Eastern Low Sulfur is \$255/ton; to Washed Warrior Run is \$438/ton; and to Raw Warrior Run is \$409/ton. All of these revised cost effectiveness values are less than the lower end of the range of costs borne by similar sources to control SO₂ (\$527/ton). Thus, fuel switching is cost effective and cannot be eliminated on economic grounds.

Second, the use of outlet SO₂ emission rates is further incorrect because it takes credit for scrubbing but does not reflect the relative costs of BACT scrubbing in the costs. For example, the cost to remove 98% of the SO₂ from petroleum coke would be much higher than the cost to remove 92% of the SO₂ from PRB coal, offsetting some of the economic benefit of using a high sulfur fuel when proper BACT controls are required. This relative cost difference is not considered in the cost calculations.

Third, the cost calculations adjust the delivered fuel cost for changes in the variable O&M (neglecting similar changes in capital costs as noted above), but base the adjustment solely on limestone. Limestone will be used in the fluidized bed and lime will be used in the spray dryer absorber selected to control SO₂ emissions from the boiler. Lime costs were apparently omitted. Lime costs considerably more than limestone. Thus, adjusted fuel costs of all of the alternate fuels would be lower than shown if lime costs were included and cost effectiveness values would be even lower than revised above.

Fourth, LDEQ compares the cost effectiveness of SO₂ control by fuel switching to costs for post combustion controls—various types of dry scrubbers and sorbent injection. 11/30/07 LDEQ Ltr at 4-5. This approach is like comparing apples to oranges. The NSR Manual explains that “where a *control technology* has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if **any**, between the application of the *control technology* on those sources and the particular source under review.” NSR Manual, p. 31 (emphasis added). The comparison, then, must be on a “control technology” basis, not on a pollutant basis, as incorrectly proffered by LDEQ. Thus, to determine cost effectiveness of fuel switching, the applicant must compare the cost of fuel switching borne by other applicants with the cost of fuel switching in this instance, not with the cost of scrubbing and sorbent injection, which are separate SO₂ control technologies. The record contains no comparative cost data for fuel switching alone.

Finally, LDEQ fails to provide *any* analysis of the cost of using lower sulfur petroleum coke. The St. John River Power Park fuel analysis done for EPA in 2005 shows the highest concentration of SO₂ in petroleum coke available nationwide did not exceed 6.28 percent, with

an average sulfur content of 5.13 percent. Nowhere does LDEQ consider use of lower sulfur petroleum coke.

e. The PSD Permit Must Set Separate SO₂ Limits for Each Type of Fuel.

The LDEQ claims that “other permitting authorities have not been *required* to establish separate limits for each potential fuel.” 11/30/07 LDEQ Ltr to EPA Region 6 at 5. This is not true. The EPA has argued in comments across the United States that SO₂ BACT emission limits should be set to assure that the maximum degree of reduction in SO₂ is achieved across the range of fuels that may be burned. Setting limits for the lower (0.08 lb/MMBtu when burning PRB and 0.15 lb/MMBtu when burning petroleum coke) does not assure that the maximum degree of reduction is met when burning a lower sulfur petroleum coke or Warrior Run. A percent reduction must be included in the permit, or, in the alternative, separate SO₂ limits for each fuel.

BACT is an emission limit based on the maximum degree of reduction that is achievable....” La. Admin. Code tit. 33, pt. III, § 509.B. If a limit is set to only achieve the maximum degree of reduction for two fuels – petroleum coke with the highest amount of sulfur and Powder River Basin (“PRB”) coal with lowest sulfur, the facility could use a lower sulfur petroleum coke or PRB coal, or other coals with lower sulfur and operate their SO₂ controls at lower control efficiencies than established as BACT, thus contravening the definition of BACT. For example, the 0.15 lb/MMBtu SO₂ BACT limit is based on 98.7% SO₂ removal from 11.6 lb/MMBtu petroleum coke. 11/30/07 LDEQ Ltr to EPA Region 6 at 4, fn 2. If the facility switches from 11.6 lb/MMBtu petroleum coke to 5 lb/MMBtu petroleum coke, it could meet its SO₂ limit by only removing 94% of the SO₂. This is not the maximum degree of reduction set as BACT for the petroleum coke case. Thus, maximum degree of reduction is not met over the full range of likely fuels, contrary to the definition of BACT, which requires an emission limit based

on the maximum degree of reduction for the full range of operating conditions. NSR Manual, p. B.56.

EPA has provided comments to this effect on many other facilities across the U.S. These include permits issued for Springfield, MO (EPA pointed out that BACT cannot assume worst-case PRB coal, especially when such coal is not representative of the PRB coal being burned at power plants in the region);¹¹ Iatan, MO;¹² Longleaf, GA;¹³ Nebraska City Station¹⁴; Holcomb Units 2-4 in Kansas¹⁵ (BACT must assume a typical PRB coal-- not the worst case PRB coal); Hastings Nebraska;¹⁶ Roundup, Montana;¹⁷ and Comanche, Colorado,¹⁸ among others. Therefore, EPA has repeatedly made the same comment—BACT for SO₂ must assume a coal sulfur content and a control efficiency to assure the applicant achieves the maximum degree of reduction over the full range of fuels proposed. This can be accomplished in two ways, first by requiring a control efficiency in the permit and second by setting tiered SO₂ limits that address the full range of fuels.

Permits have been issued addressing these comments. The Longleaf PSD permit, issued by Georgia Department of Environmental Quality, required separate SO₂ limits for two separate

¹¹ Letter from JoAnn Heiman, Acting Chief, Air Permitting and Compliance Branch, U.S. EPA Region 7, to Leann Tippet Mosby, Staff Director, Missouri Department of Natural Resources, June 30, 2004.

¹² Letter from JoAnn Heiman, Chief, Air Permitting and Compliance, U.S. EPA Region 7, to Jim Kavanaugh, Director, Missouri Department of Natural Resources, December 5, 2005

¹³ Letter from Greg M. Worley, Chief, Air Permits Section, Heather Abrams, Chief, Air Protection Branch, Georgia Department of Environmental Protection Division, November 16, 2006.

¹⁴ Letter from JoAnn M. Heiman, U.S. EPA Region 7, to W. Clark Smith, Nebraska Department of Environmental Quality, Re: Nebraska City Station, January 26, 2005.

¹⁵ Letter from JoAnn M. Heiman, U.S. EPA Region 7, to Clark Duffy, Kansas Department of Health & Environment, Re: Holcomb Units 2-4, November 9, 2006.

¹⁶ Letter from JoAnn M. Heiman, Air Permitting and Compliance Branch, U.S. EPA Region 7, to W. Clark Smith, Nebraska Department of Environmental Quality, Re: Hastings, Nebraska, August 4, 2006.

¹⁷ E-mail from Hans Buening, U.S. EPA Region 8, to Sam Portanova, U.S. EPA Region 5, Re: Roundup, October 1, 2004.

¹⁸ Letter from Richard R. Long, U.S. EPA Region 8, to Douglas H. Benevento, Colorado Department of Public Health, May 12, 2005.

fuels, Powder River Basin and Central Appalachian coals, as requested by EPA Region 4. This permit further sets tiered SO₂ limits spanning the range of likely fuel sulfur contents. Elsewhere, the Newmont and White Pine PSD permits, both located in Nevada, contain separate fuel sulfur limits and SO₂ control efficiency to bound the range of likely fuel sulfur contents, and to assure that the facility achieves the maximum degree of reduction. Petitioners urge that separate BACT limits are required for the upper and lower end of the range of the probable future sulfur content.

2. **The Permits Unlawfully Exclude Startup, Shutdown, and Malfunction Periods from Emissions Limits.**

The Permits effectively create an illegal blanket exception to BACT requirements for periods of startup, shutdown, and malfunction. “BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown.” *In re Tallmadge Generating Station*, PSD Appeal No. 12-12, at 24 (E.A.B. 2003). PSD permits “may not contain blanket exemptions allowing emissions in excess of BACT limits during startup and shutdown.” *Id.* at 25. Setting a separate emissions limit during SSM periods requires an on-the-record determination “of the specific reasons for conclusion of infeasibility” of BACT limit compliance. *Id.* at 27. This discussion must include a description of “design, control, methodological, or other changes [that] are appropriate for inclusion in the permit to minimize the authorized excess emissions during startup and shutdown.” *Id.* PSD permits may impose separate emissions requirements during times of SSM, but they may not completely eliminate emissions requirements.

Specific Requirements 136,¹⁹ and 137²⁰ of the Title V Permit exclude times of SSM and emergency operating conditions from calculations that determine compliance with emissions

¹⁹ “Determine compliance with the SO₂ and NO_x emission standards by calculating the arithmetic average of all hourly emission rates for SO₂ and NO_x for the 30 successive boiler days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO₂ only).”

standards. Specific Requirements 131²¹ and 130²² of the Title V permit allow noncompliance with federal particulate matter and NO_x standards during periods of SSM. Specific Requirement 184 establishes an opacity limit, “except during the cleaning of a fire box or building of a new fire, soot blowing or lancing, charging of an incinerator, equipment changes, ash removal or rapping of precipitators.” The effect of excluding these conditions from the compliance calculations is to allow unlimited emissions of NO_x and particulate matter during SSM periods. Without additional limitations during periods of SSM, Specific Requirements 130, 131, 136, 137 and 184 constitute unlawful blanket exemptions to BACT requirements.

3. PSD Analysis Fails to Consider Effect of SO₂ Emissions on Breton National Wildlife Refuge.

The regulations state that the “owner or operator shall provide an analysis of the air quality impact projected for the area.” *Id.* § III:509(O)(2). No pollutant concentration may exceed the lesser of the primary and secondary national ambient air quality standards (“NAAQS”) for the period of exposure. *Id.* § III:509(D). Entergy used CALPUFF modeling to determine the impact of its SO₂ emissions on the Class I Breton National Wildlife Refuge, using assumed SO₂ emissions of 424.2 lb/hr for each of the boilers, or 848.4 lb/hr for both boilers. *Permit Application PSD Class I Modeling Analysis Report at 2-5.* However, the PSD Permit allows a maximum of 2279 lb/hr of SO₂ for each boiler during startup and shutdown conditions, allowing a total of 4558.24 lb/hr for both boilers during a startup or shutdown. PSD Permit, Specific Conditions, Max Allowable Emissions Rates. The maximum limit in the PSD Permit is

²⁰ “Determine compliance with particulate matter emission limitations by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.”

²¹ “Comply with the particulate matter emission standards under 40 CFR 60.42Da at all times except during periods of startup, shutdown, or malfunction.”

²² “Comply with the nitrogen oxides emission standards under 40 CFR 60.44Da at all times except during periods of startup, shutdown, or malfunction.”

over five times the amount Entergy modeled. Consequently, the maximum allowable emission rate of 2279.12 lb/hr for each boiler during SSM periods in the PSD permit is not representative of the emissions analyzed by Entergy for the Class I Brenton National Wildlife Refuge. This causes the Class I analysis used to support the PSD Permit to under represent the impacts to air quality at the Brenton Nation Wildlife Refuge. Therefore, for the maximum SO₂ limits in the PSD Permit are invalid. Entergy must be required evaluate the impact of 2279.12 lb/hr of SO₂ per boiler on the ambient air of the Brenton National Wildlife Refuge and show that the SO₂ concentration does not exceed the lesser of the primary and secondary NAAQS for the period of exposure. *Id.* § III:509(D).

Further, Louisiana regulations limit ambient air increases over baseline in Class I areas based on three hour, twenty-four hour, and annual measurements. La. Admin. Code tit. 33, § III:509(C). Specific Requirement 212 of the Title V Permit limits SO₂ emissions on the basis of a thirty-day rolling average, but fails to include limits based on a three-hour averaging time.

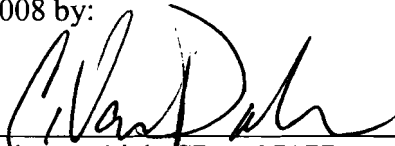
CONCLUSION

For the foregoing reasons, Petitioners ask that the Administrator object to the Title V Air Operating Permit Major Modification (permit no. 2520-00009-V1) and Prevention of Significant Deterioration Permit (PSD-LA-720) issued to Entergy by LDEQ.

Prepared by:

Emon Mahony, Law Student,
TULANE ENVIRONMENTAL
LAW CLINIC

Respectfully submitted this 9th day of January,
2008 by:



Adam Babich, SBN: 27177

Corinne Van Dalen, SBN: 21175

TULANE ENVIRONMENTAL LAW CLINIC

6329 Freret Street

New Orleans, Louisiana 70118

phone (504) 865-8814

fax (504) 862-8721

ababich@tulane.edu; cvandale@tulane.edu

Counsel for Sierra Club, Louisiana

Environmental Action Network, Gulf Restoration,

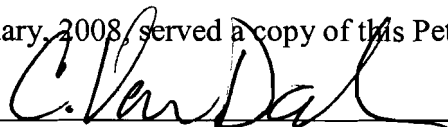
Alliance for Affordable Energy, and Sal

Giardina, Jr. Gulf Restoration, Alliance for

Affordable Energy, and Sal Giardina, Jr.

CERTIFICATE OF SERVICE

I hereby certify that I have this 9th day of January, 2008, served a copy of this Petition to those listed below.



Corinne Van Dalen

Stephen Johnson, Administrator (U.S. certified mail)

U.S. EPA Headquarters

Ariel Rios Bldg.

1200 Penn. Ave., NW

Mail Code 1101A

Washington, D.C. 20460

Mike D. McDaniel, Ph.D. (via U.S. certified mail)

Secretary

Louisiana Department of Environmental Quality

P.O. Box 4301

Baton Rouge, LA 70821-4301

Phone: (225)219-3953

Entergy Louisiana, LLC (via certified U.S. mail)

c/o Registered Agent T Michael Twomey

4809 Jefferson Hwy.

Jefferson, LA 70121

Ms. Cherly S. Nolan
Administrator
LDEQ, Air Permits Division
P.O. Box 4313
Baton Rouge, LA 70821-4313

Mr. Dustin Duhon
Environmental Chemical Specialist
LDEQ, Air Permits Division
P.O. Box 4313
Baton Rouge, LA 70821-4313

Mr. Jeffery Robinson
Chief, Air Permits Section (6PD-R)
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Ms. Shannon Snyder
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Mail Code: 6PDR
Dallas, TX 75202-

Karen H. Freese, Senior Counsel
Entergy Services, Inc.
639 Loyola Ave.
Mail Unit L-ENT-26E
New Orleans, Louisiana 70113