BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of the Proposed Operating
Permit for the Cash Creek Generation Station
in Henderson County, Kentucky.

Source I.D. No. 21-101-00134

Permit No. V-07-017

Proposed by the Kentucky Environmental
Protection Cabinet Department for
Environmental Protection Division for Air
Quality on November 30, 2007.

PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF THE PROPOSED TITLE V OPERATING PERMIT FOR THE CASH CREEK GENERATION STATION IN HENDERSON COUNTY, KENTUCKY.

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Date: January 31, 2008

Pursuant to Clean Air Act § 505(b)(2) and 40 CFR § 70.8(d), the Sierra Club hereby petitions the Administrator ("the Administrator") of the United States Environmental Protection Agency ("U.S. EPA") to object to proposed Title V Operating Permit for the Cash Creek Generation Station, Henderson County, Kentucky ("Permit" or "Proposed Permit"). A copy of the Permit is attached as Exhibit A. The Permit was proposed to U.S. EPA by the Kentucky Department for Environmental Protection Division for Air Quality (hereinafter "KDAQ") more than 45 days ago. Sierra Club provided comments to the KDAQ on the draft permit. A true and accurate copy of Sierra Club's written comments is attached at Exhibit B. DAQ responded to comments; a copy of KDAQ's response to comments is attached as Exhibit C.

This petition is filed within sixty days following the end of U.S. EPA's 45-day review period, as required by Clean Air Act ("CAA") § 505(b)(2). The Administrator must grant or deny this petition within sixty days after it is filed. If the U.S. EPA Administrator determines that the Permit does not comply with the requirements of the CAA, or any "applicable requirement," he must object to issuance of the permit. 42 U.S.C. § 7661b(b); 40 C.F.R. § 70.8(c)(1) ("The [U.S. EPA] Administrator will object to the issuance of any permit determined by the Administrator not to be in compliance with applicable requirements or requirements of this part."). "Applicable requirements" include, *inter alia*, any provision of the Kentucky State Implementation Plan ("SIP"), including Prevention of Significant Deterioration ("PSD") requirements, any term or condition of any preconstruction permit, any standard or requirement under Clean Air Act sections 111, 112, 114(a)(3), or 504, acid rain program requirements. 40 C.F.R. § 70.2. "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 Electric Generating Plant*, Petition No. 6-99-2 at p. 2 (EPA Adm'r 1999). Therefore, the Administrator must look at whether an emission unit has gone through

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Here, the Administrator must object to the Proposed Permit for the Cash Creek plant because the Permit fails to comply with all applicable requirements, including SIP requirements and PSD permitting requirements. 42 U.S.C. § 7661d(b); 40 C.F.R. § 70.8(d); *New York Public Interest Research Group v. Whitman*, 321 F.3d 316, 333 n.11 (2nd Cir. 2002).

I. THE CLEAN AIR ACT REQUIRES THAT BACT LIMITS BE ESTABLISHED BASED ON CLEANER NATURAL GAS FUEL.

Congress specifically defined BACT to require consideration of less-polluting fuels as a way to reduce emissions. 42 U.S.C. § 7479(3) (defining BACT as the "maximum degree of reduction achievable... through... clean fuels..."). The applicable Kentucky SIP also defines BACT as requiring consideration of less-polluting fuels. 401 KAR 51:001, § 1(25). The legislative history of the Clean Air Act confirms that Congress intended to create a preference for lower polluting fuels. The 1990 Clean Air Act Amendments revised section 169(3) to expressly require "clean fuels" as a pollution control option that must be considered when determining BACT. Pub. L. No. 549 § 403(d), 104 Stat. 2399, 2631-32. EPA's contemporaneous interpretation of this amendment was that the "clean fuels" requirement in the definition of BACT codifies the policy "that clean fuels are an available means of reducing emissions to be considered along with other approaches in identifying BACT level controls." Letter from William Rosenberg, U.S. EPA Assistant Adm'r for Air and Radiation, to Henry A.

Waxman, Chair, Subcommittee on Health and Environment (Oct. 17, 1990), reprinted in 136 Cong. Rec. at S16916-17.

If there were any doubts as to what Congress intended when it required a permitting agency to consider clean fuels when establishing BACT limits, EPA put them to rest:

> The phrase 'clean fuels' was added to the definition of BACT in the 1990 Clean Air Act amendments. EPA described the amendment to add 'clean fuels' to the definition of BACT at the time the Act passed, 'as * * * codifying its present practice, which holds that <u>clean fuels are an available means of reducing emissions to be considered along with other approaches to identifying BACT level controls</u>.' EPA policy with regard to BACT has for a long time required that the permit writer examine the inherent cleanliness of the fuel.

Inter-Power of New York, 5 E.A.D. 130, 134 (EAB 1994) (emphasis added, internal citations omitted); *see also In re Knauf Fiberglass, GmbH*, 8 E.A.D. 121, 136 (EAB 1999); *Old Dominion Electric Cooperative*, 3 E.A.D. at 779, 794 n. 39 (1992) ("BACT analysis should include consideration of cleaner forms of the fuel proposed by the source."); *Hibbing Taconite*, 2 E.A.D. 838, 842-843 (EPA Adm'r 1989) (remanding a permit because the permitting agency failed to consider burning natural gas as a viable pollution control strategy); *In re East Kentucky Power Coop. Inc.*, Order Objecting to State Issued Permit V-06-007 at p. 30 (EPA Adm'r. Aug. 30, 2007) (objecting to Title V permit issued by Kentucky for failure to demonstrate that cleaner fuel, low sulfur coal, was not achievable and should not be used to establish BACT); U.S. EPA Region 4, Air Permits Section, Comments on Draft PSD Permit for Duke Energy Carolinas, LLC, Cliffside

Steam Station, Unit 6 Project at 4 (Oct. 3, 2007) (because the proposed unit can burn either subbituminous or bituminous coal, the fuel type is not fundamental to the project and BACT must be established based on the cleaner PRB coal) (attached as Exhibit D). "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, 655 (7th Cir. 2007). The United States Court of Appeals for the Ninth Circuit similarly held, in *Hawaiian Elec. Co., Inc. v. EPA*, that low sulfur fuel could be selected as BACT for a facility proposing to burn high sulfur fuel. 723 F.2d 1440, 1442 (9th Cir. 1984).

The proposed Cash Creek plant will be capable of burning either synthetic gas made from coal or natural gas. *See e.g.*, Proposed Permit § B, Emission Units 01 & 02, 1.a. In fact, the applicant acknowledges that it does not intend to burn synthetic gas in the combustion turbines for the first 6 to 12 months of operation and, instead, intends to operate the combustion turbines solely on natural gas. *See* Response to Comments at p. 3 ("This change is requested because the combined cycle power block is expected to commence operational testing with natural gas fuel approximately six (6) to twelve (12) months prior to the introduction of synthesis gas from the gasifiers.")

Despite being able to burn clean natural gas, the Permit does not establish BACT limits based on cleaner natural gas—but instead provides two limits, depending on which fuel is used—lower limits for clean natural gas and higher limits for dirtier synthetic gas. These limits are set forth in the following table.

	Synthetic Gas Limit	Natural Gas Limit
NOx	0.0331 lb/MMBtu	0.0246 lb/MMBtu
CO	0.0485 lb/MMBtu	0.0449 lb/MMBtu
PM- filterable	0.0085 lb/MMBtu	N/a
PM-condensable	0.0217 lb/MMBtu	0.0063 lb/MMBtu
SO2	0.0158 lb/MMBtu	0.0006 lb/MMBtu
H2SO4	0.0035 lb/MMBtu	0.0001 lb/MMBtu

Proposed Permit § B, Emission Units 01 & 02 pp. 3-4. In other words, KDAQ expressly recognized that when the combustion turbines are fired on natural gas, the facility will achieve lower emission rates than when it fires synthesis gas. Nevertheless, KDAQ failed to establish the BACT limit based on the clean fuel, as required by the plain meaning of BACT. 42 U.S.C. § 7479(3); 401 KAR 51:001, sec. 1(25).

The use of a clean fuel in this plant does not impermissibly require the redesign of a facility. The facility's preference to use dirtier synthetic fuel is not a fundamental design that is immune from consideration in a BACT determination. The Seventh Circuit held that an applicant cannot dictate the specific fuel to be used in a BACT determination because such an interpretation would eviscerate the statute's clear requirement to consider clean fuels other than the fuel proposed by the applicant. Discussing a change from high sulfur to low sulfur coal in that case, the Seventh Circuit held that an applicant cannot escape some changes to its preferred design when necessary to allow Congress' intent to establish BACT limits based on clean fuel.

> Some adjustment in the design of the plant would be necessary in order to change the fuel source from high-sulfur to low-sulfur coal, but if it were no more than would be necessary whenever a plant switched from a dirtier to a cleaner fuel the change would be the adoption of a "control

> technology." Otherwise "clean fuels" would be read out of the definition of such technology.

Sierra Club, 499 F.3d at 656. In fact, both the Environmental Appeals Board and the Seventh Circuit in the Prairie State case noted that it is not the *burning* of an alternative fuel, but the structures to receive a different fuel (coal from a distant mine in that case) that would require a redesign beyond that envisioned by the Act. *Id.* at 657; see also *In re Hibbing Taconite Company*, 2 E.A.D. at 842-43 (Adm'r 1989) (explaining that the "redefining the source" policy only prevents the permitting agency from requiring the applicant to build a different type of facility, not a fuel with different characteristics).

KDAQ's only reaction to Sierra Club's comment about clean fuel was to state that the ICGG will use coal to produce synthesis gas (syngas) as the primary fuel (natural gas is a secondary fuel). Response to Comments at p. 24. This response does not address the comment, however, because a BACT determination is not dependant on an arbitrary assertion of primary vs. secondary fuels. Moreover, KDAQ's response fails to recognize that the plant can burn natural gas as the primary fuel and will do so for six months to a year.

Here, the plant would not require a redesign to burn cleaner natural gas. Indeed, the applicant *intends* to burn natural gas—not only as a backup fuel, but as the primary fuel for the first six months to year of operation. Unless the applicant demonstrates that the use of clean-fuel natural gas is not cost-effective (there is no technological, energy or environmental impacts) the BACT limits must be based on this clean fuel. *Citizens for Clean Air v. EPA*, 959 F.2d 839, 845 (9th Cir. 1992) ("The top-down approach places the burden of proof on the applicant to justify why the proposed source is unable to apply the best technology available."); *see also In re: Spokane Regional Waste-to-Energy Applicant,* PSD Appeal No. 88-12 (EPA June 9, 1989)); *NSR Manual* at B.2; *see also In re: Inter-Power of New York, Inc.* 5 E.A.D. 130, 135 (EAB 1994) ("Under the 'top-down' approach, permit applicants must apply the most stringent control alternative, unless the applicant can demonstrate that the alternative is not technically or economically achievable."); *In re Pennsauken County, New Jersey Resource Recovery Facility,* 2 E.A.D. 667 (Adm'r 1988), available at 1988 EPA App. LEXIS 27, 28 (Nov. 10, 1988) ("Thus, the 'top-down' approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best technology available.").

There is no evidence in the record that burning natural gas is not cost effective. Therefore, it cannot be rejected for that reason. "Before a control option may be rejected on cost-effectiveness grounds, the [agency] must have a reasonably accurate idea what the cost-effectiveness is." *In re Masonite Corp.,* 5 E.A.D. 551, 566 (EAB 1994). Moreover, the fact that the facility will burn natural gas only for six months or more, and that many other facilities burn natural gas in combustion turbines to generate electricity, belies any suggestion that doing so is not cost-effective.

The failure to establish lower BACT limit based on clean natural gas results in limits that do not satisfy the requirement for BACT limits. This results in a deficient permit and requires an objection by the Administrator.

II. THE NSPS STANDARD FOR STATIONARY COMBUSTION TURBINES APPLIES.

The Proposed Permit fails to include applicable requirements for the combustion turbines based on 40 C.F.R. pt. 60, Subpart KKKK. The Statement of Basis for the draft permit indicated that the combustion turbines would fire at least 50% synthetic coal gas. Based on this assumption, KDAQ determined that subpart KKKK would not apply. However, as became apparent in the applicant's comments on the draft permit, the applicant intends to run the combustion turbines on natural gas only for the first 6 to 12 months. *See* Response to Comments, Appx. A at p. 3. Therefore, it is not correct, as KDAQ assumed, that the turbines will burn more than 50% synthetic gas fuel. Instead, the turbines are subject to the NSPS standard in Subpart KKKK. The failure to include those applicable NSPS requirements necessitates an objection by the Administrator.

III. THE PERMIT LACKS A PM2.5 BACT LIMIT.

The KDAQ identified PM2.5 as a pollutant subject to BACT. Revised Statement of Basis at 14 ("The following pollutants are subject to BACT:... PM2.5...") However, the Permit does not include a BACT limit for PM2.5 emissions. Kentucky's PSD program, which is incorporated into the Kentucky SIP, requires a BACT limit "for <u>each</u> regulated NSR pollutant for which the source has the potential to emit in significant amounts." 401 KAR 51:017, sec. 8(2). A "regulated NSR pollutant" includes any "pollutant for which a national ambient air quality standard has been promulgated..." and any other "pollutant that otherwise is subject to regulation under 42 U.S.C. 7401 to 7671q...." 401 KAR 51:001, Section 1(210)(a), (d). As KDAQ admits, PM2.5 is a "regulated NSR pollutant" because EPA established a "national ambient air quality standard" for PM2.5 in 1997. 62 Fed. Reg. 38711; 40 C.F.R. § 50.7.

Sierra Club commented on the lack of a PM2.5 BACT limit. KDAQ responded that:

> While the Division acknowledges that PM2.5 is a regulated pollutant, at this time EPA has not yet implemented NSR regulations for PM2.5 NAAQS. It is well established that EPA has proposed the interim use of PM10 as a surrogate for PM2.5 until NSR rules have been implemented. EPA has represented that:
>
> "In view of the significant technical difficulties that now exist with respect to PM2.5 monitoring, emissions, estimation, and modeling, EPA believes that PM0 may properly be used as a surrogate for PM2.5 in meeting NSR requirements until these difficulties are resolved. When the technical difficulties are resolved, EPA will amend the PSD regulations under 40 C.F.R. § 51.166 and 52.21 to establish a PM2.5 significant emission rate and EPA will also promulgate other appropriate regulatory measures pertinent to PM2.5 and its precursors."
>
> Memorandum from John Seitz, Office of Air Quality Planning and Standards, "Interim Implementation of New Source Review Requirements for PM2.5" (October 2, 1997).
>
> This position was recently reaffirmed in specific guidance to the states:
>
> "Using the surrogate PM2.5 nonattainment major NSR program, States should assume that a major-stationary source's PM0 emissions represent PM2.5 emissions and regulate tese emissions using either Appendix S or the State's SIP-approved nonattainment major NSR program.
>
> Memorandum from Stephen Page, Office Air Quality and Planning and Standards (April 5, 2005).

Response to Comments at 23.

Because PM2.5 is undoubtedly a "regulated NSR pollutant" under 401 KAR 51:001, sec. 1(210), KDAQ cannot duck its obligation to establish a BACT limit. PM2.5 will be emitted from the Cash Creek facility in a "significant" amount because there is no dispute that it will be emitted at "any emission rate." 401 KAR 51:001, sec. 1(221)(b); 401 KAR 51:017, sec. 8(2). KDAQ, and for that matter U.S. EPA, cannot piggyback one regulatory failure on another. The fact that U.S. EPA failed to establish specific implementing regulations for PM2.5 for a decade after PM2.5 because a regulated pollutant does not further excuse states from implementing the plain language requirement to set BACT limits for PM2.5. Nothing in the Kentucky SIP conditions the requirement to establish BACT limits on U.S. EPA first establishing implementation protocols and reference test methods. 401 KAR 51:001, sec. 1(210), (221), and 401 KAR 51:017, sec. 8(2). Instead, the SIP plainly requires a BACT limit. *Id.*

Moreover, as EPA, itself, has acknowledged, the Page and Seitz memos cited by KDAQ are merely guidance and cannot trump the statutory and regulatory requirements of the Clean Air Act.

> [The state] cites EPA policy guidance as saying that "States should use PM10 as a surrogate for PM2.5" until federal PM2.5 NSR implementation regulation rules are promulgated. While this is a reasonable depiction of current EPA policy guidance, please note that EPA has also said (in its April 5, 2005, policy guidance memo) that "statements in this policy guidance do not bind State and local governments and the public as a matter of law."

U.S. EPA Region 4, Air Permits Section, Comments on Draft PSD Permit for Duke Energy Carolinas LLC, Cliffside Steam Station, Unit 6 Project at p. 6 (Oct. 31, 2007); *see* *also* Memorandum from Stephen Page, Implementation of New Source Review Requirements in PM-2.5 Nonattainment Areas, p. 4 ("The statements of [the 1997 Seitz memo] do not bind State and local governments and the public as a matter of law.").

Furthermore, the bases for the Seitz and Page memos no longer exist. The U.S. EPA issued a draft PM2.5 implementation rule on November 1, 2005, in which it stated: "To date, some permitted entities have been using PM10 emissions as a surrogate for PM2.5 emissions. Upon promulgation of this rule, EPA will no longer accept the use of PM10 as a surrogate for PM2.5." 70 Fed.Reg. 66,057 (November 1, 2005). The preamble to the draft rule also reconfirmed that the difficulties in testing, emission estimating and modeling, which were the basis of the original surrogate proposal in the Seitz Memo, no longer existed. *Id.* The final implementation rule, published April 25, 2007, stated as to Title V regulations: "To date, some permitted entities have been using PM10 emissions as a surrogate for PM2.5 emissions. Upon promulgation of this rule, EPA will no longer accept the use of PM10 as a surrogate for PM2.5." 72 Fed. Reg. 20,659 (April 25, 2007). If there were any doubt that PM2.5 must be regulated as a separate pollutant from PM10, EPA stated: "In summary, the purpose of the statements made in the preamble to the proposal was to notify sources that as of the promulgation of this final rule, the EPA will no longer accept the use of PM10 emissions information as a surrogate for PM2.5 emissions information [] given that both pollutants are regulated by a National Ambient Air Quality Standard and therefore are considered regulated air pollutants." *Id.* at 20,660.

Thus, the final implementation rule clarifies that PM2.5 data must be used for NSR permitting: "Circumstances necessitating the quantification of PM2.5 emissions and the submittal of this information include: (1) Determining all of the pollutants for which a source is major; (2) determining whether an applicable requirement or program applies, e.g., determining the applicability of a SIP requirement or a PSD or nonattainment NSR program, etc; or (3) determining what fees a source owes a permitting authority as a result of considering PM2.5 emissions." 72 Fed. Reg. at 20,659. There is simply no remaining doubt that PM2.5 must be addressed as PM2.5 and not as PM10 for PSD permitting.

Furthermore, the premise for U.S. EPA establishing NAAQS for PM2.5 was that the PM10 standards were not sufficient. In establishing the PM2.5 standard, EPA recognized that "The characteristics, sources and potential health effects of larger or 'coarse' fraction particles (from 2.5 to 10 microns in diameter) and smaller for 'fine' particles (smaller than 2.5 microns in diameter) are very different." National Ambient Air Quality Standards for Fine Particles: Guidance for Designating Areas: Fact Sheet, U.S. EPA (July 17, 1997) available at http://www.epa.gov/ttn/oarpg/t1/fact_sheets/pmfact.pdf; *see also* Proposed Rule to Implement the Fine Particle National Ambient Air Quality Standards, 71 Fed. Reg. 65,984, 65,992 (November 1, 2005) (stating that PM10 and PM2.5 "are generally associated with distinctly different source types and formation processes"); 72 Fed. Reg. 20,586, 20599 (April 25, 2007) (noting that PM2.5 and PM10 are different "in terms of atmospheric dispersion characteristics, chemical composition, and contribution from regional transport"); *id.* at 589 (stating that "[i]n contrast to PM[10], EPA anticipates that achieving the NAAQS for PM[2.5] will generally require States to evaluate different sources for controls, to consider controls of one or more precursors [to PM2.5] in addition to direct PM emissions, and to adopt different control strategies."). In light of that finding, reverting to compliance with PM10 standards as a surrogate for PM2.5 standards is inadequate. The Administrator must object to the Permit and KDAQ must include a BACT limit for PM2.5.

IV. THE PERMIT LACKS A BACT LIMIT FOR CO2.

The Clean Air Act prohibits the construction of a new major stationary source of air pollutants except in accordance with a prevention of significant deterioration (PSD) construction permit. 42 U.S.C. § 7475(a); 40 C.F.R. §52.21(a)(2)(iii); 401 KAR 51:107. As noted above for PM2.5, a significant increase in emissions of any pollutant subject to regulation under the Clean Air Act is subject to the PSD program. Because Carbon Dioxide (CO2) has been regulated under the Clean Air Act since 1993, and will be emitted in a "significant" amount[1] from the Cash Creek plant, the Title V permit for the facility must include a CO2 BACT limit.

Section 821(a) of the Act provides:

> Monitoring. - The Administrator of the Environmental Protection Agency **shall promulgate regulations** within 18 months after the enactment of the Clean Air Act Amendments

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[1] 401 KAR 51:001, Section 1(222) (significant for any "regulated NSR pollutant that is not listed in [401 KAR 51:001(222)(a)] <u>any</u> emissions rate" (emphasis added)). There is no dispute that there will be an increase in CO2 of "any" amount.

> of 1990 **to require that all affected sources subject to the Title V of the Clean Air Act shall also monitor carbon dioxide emissions** according to the same timetable as in Sections 511(b) and (c). **The regulations shall require that such data shall be reported to the Administrator.** The provisions of Section 511(e) of Title V of the Clean Air Act shall apply for purposes of this section in the same manner and to the same extent as such provision applies to the monitoring and data referred to in Section 511.

42 U.S.C. 7651k note; Pub.L. 101-549; 104 Stat. 2699 (emphasis added). In other words, Congress specifically ordered EPA "to promulgate regulations" requiring that facilities covered by Title IV of the Act monitor and report their CO_2 emissions in § 821. EPA's §821 regulations, promulgated under the authority in the Clean Air Act, and therefore constitution regulations "under the Act," were finalized on January 11, 1993 and require CO_2 emissions monitoring. 40 CFR §§75.1(b), 75.10(a)(3), 75.33, 75.57, 75.60 – 75.64. These requirements, including the requirement to monitor CO2, are also included in various state implementation plans, including Wisconsin's. *See* Wis. Admin. Code §§ NR 438.03(1)(a) (requiring reporting of pollutants listed in Table I, including CO2), adopted under the Act at 40 C.F.R. § 52.2570(c)(70)(i); NR 439.095(1)(f) (Phase I and phase II acid rain units… shall be monitored for… carbon dioxide…"), adopted under the Act at 40 C.F.R. § 52.2570(c)(73)(i)(I). Compliance is mandated by 40 CFR §75.5, which prohibits operation in violation of the CO2 monitoring and reporting requirements and provides that a violation of any Part 75 requirement is a violation of the Act.

While these regulations require monitoring and reporting, rather than establishing a cap on CO2 emissions, that distinction is irrelevant. The plain language meaning of "regulation" includes monitoring and reporting. The most basic canon of statutory interpretation is that words should be given their plain meaning, and Webster's defines "regulation" as "an authoritative rule dealing with details or procedure; (b) a rule or order issued by an executive authority or regulatory agency of a government and having the force of law." Section 821, as well as the implementing regulations in Part 75 and various SIPs, are enforceable CO2 rules, constituting "regulation under the Act." Indeed, the Supreme Court has long held that information gathering, record keeping, and data publication rules are indisputably within the conventional understanding of "regulation." *Buckley v. Valeo*, 424 U.S. 1, 66-67 (1976) (record keeping and reporting requirements are regulation of political speech). Moreover, as the Court in *Alabama Power Co. v. Costle*, 636 F.2d 323, 403 (D.C. Cir. 1979), held, PSD applies to pollutants in addition to those for which air quality standards or other limits have been promulgated:

> The only administrative task apparently reserved to the Agency . . . is to identify those . . . pollutants subject to regulation under the Act which are thereby comprehended by the statute. The language of the Act does not limit the applicability of PSD only to one or several of the pollutants regulated under the Act,
>
> ... the plain language of section 165... in a litany of repetition, provides without qualification that each of its major substantive provisions shall be effective after 7 August 1977 with regard to each pollutant subject to regulation under the Act, or with regard to any

> "applicable emission standard or standard of performance under" the Act. As if to make the point even more clear, the definition of BACT itself in section 169 applies to each such pollutant. The statutory language leaves no room for limiting the phrase "each pollutant subject to regulation."
>
> ....

On April 2, 2007, the Supreme Court reconfirmed that that carbon dioxide and other greenhouse gases are "pollutants" under the Clean Air Act—clarifying that they are, indeed, "*subject to* regulation." *Massachusetts v. EPA*, 127 S.Ct. 1438, 1460 (2007).

KDAQ rejected Sierra Club's comments on the lack of a CO2 BACT limit by merely stating:

> The definition of Best Available Control Technology found at 401 KAR 51:001, Section (25) is clear that BACT is required for "each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification..." Major stationary source and major modification are also clearly defined according to emissions of regulated NSR pollutants for which a NAAQS has been promulgated, pollutants subject to NSPS under Section 111 of the CAA, Class I and II substances subject to a standard under Section 602 of the CAA, and pollutants otherwise subject to regulations under the CAA. 401 KAR Section 51:001 Section 1(210).
>
> No NAAQS or NSPS has been established for carbon dioxide (CO2), CO2 is not a Class I or II substance nor is it otherwise regulated under any provision of the CAA at this time. Therefore, no BACT analysis is required for CO2 in this permit application and approval. Kentucky is required by statute to implement a PSD program that is no more stringent than federal requirements. KRS 224.10-100(26). Where there are no federal regulations establishing requirements for CO2 at stationary sources, Kentucky is prohibited from imposing any such requirements.

Response to Comments at 42.

KDAQ is incorrect that BACT only applies to pollutants subject to a NAAQS or NSPS standard or that is a Class I or Class II substance under Clean Air Act section 602. Both the Act and the Kentucky SIP require BACT "for each pollutant subject to regulation under" the Clean Air Act—or "Regulated NSR Pollutant." 42 U.S.C. § 7475(a)(4); 401 KAR 51:017, § 8. The Kentucky SIP (and 40 C.F.R. pts. 51 and 52) define a "Regulated NSR Pollutant" as one of four categories:

1) a pollutant for which a NAAQS has been promulgated;
2) a pollutant subject to an NSPS standard;
3) a class I or class II substance (42 U.S.C. §§ 7671-7671q); or
4) "A pollutant that is otherwise subject to regulation under 42 U.S.C. 7401 to 767q, except that any hazardous air pollutant (HAP) listed in 42 U.S.C. 742(b)(2)..."

401 KAR 51:001, Section 1(211). KDAQ's interpretation would limit "Regulated NSR Pollutant" to the first three categories, rendering the fourth category mere surplusage, contrary to the applicable cannons of interpretation that prohibit such interpretation. *Babbitt v. Sweet Home Chapter of Cmtys. for a Great Or.*, 515 U.S. 687, 698 (1995) (applying the cannon of interpretation disfavoring an interpretation that renders statutory language surplusage). Put another way, for the fourth subcategory to have any meaning, it must include pollutants other than those for which a NAAQS has been established, those controlled by an NSPS standard, or those Class I and Class II ozone depleting substances covered by the first, second and third subcategories in the

definition of "Regulated NSR Pollutant." Moreover, if only those pollutants that are subject to a NAAQS, NSPS or ozone depleting substance provision were regulated pollutants for purposes of a BACT limit, there would have been no purpose to expressly exclude pollutants regulated under CAA § 112, as the fourth category of Regulated NSR Pollutants does.

In short, there plain language of the Clean Air Act does not support KDAQ's attempt to artificially limit BACT to pollutants subject to NAAQS, NSPS or CAA § 602. CO2 is clearly a pollutant subject to regulation under the Act and, therefore, subject to a BACT limit. The permit lacks the mandatory CO2 BACT limit and the Administrator must, therefore, object.

V. KDAQ UNLAWFULLY TRUNCATED ITS ANALYSIS OF ALTERNATIVES AND THE PUBLIC INPUT TO ALTERNATIVES UNDER THE CLEAN AIR ACT BASED ON AN INAPPLICABLE STATE STATUTE.

Sierra Club commented to KDAQ that Clean Air Act section 165(a)(2) provides the public an opportunity to comment on the proposed source, including "alternatives thereto" and "other appropriate considerations." 42 U.S.C. § 7475(a)(2). Sierra Club further commented that CO2 must be considered as part of this process and noted a number of methods to reduce the CO2 impact from the Cash Creek plant.

KDAQ ignored these comments, despite the fact that they are expressly provided for in section 165(a)(2), based on KDAQ's apparent belief: (1) that the comments were based on the Kyoto Protocol; and (2) that state law can trump the Clean Air Act. *See* Response to Comments at 33 ("The Division is expressly prohibited from promulgating administrative regulations or imposing permit conditions on the emission of carbon dioxide or other green house gases pursuant to the Kyoto Protocol for the purpose of reducing global warming until authorized by the General Assembly or by federal statute. KRS 224.20-125.") KDAQ fails to understand that Sierra Club's comments specifically referenced, and are provided for, under CAA section 165. The comments were not referencing the "Kyoto Protocol." Moreover, even if the comments somehow implicated the Kyoto Protocol, the fact that CAA § 165 requires KDAQ to consider global warming aspects of permitting a new plant when raised by the public means that KRS 224.20-125 is not implicated. *See* KRS 224.20-125 (providing that the statute does not control when consideration of CO2 is provided for by federal statute).

KDAQ's refusal to consider Sierra Club's comments pursuant to CAA § 165(a)(2) is unlawful. Section 165 is an "applicable requirement" for a new major source construction under the Act, as is the parallel requirement in the Kentucky SIP. 401 KAR 51:017, Section 15; 40 C.F.R. § 51.166(q)(2)(v). KDAQ's failure to comply requires an objection by the Administrator. 42 U.S.C. § 7661d(b).

VI. KDAQ ERRONEOUSLY FAILED TO CONSIDER LOWER SAM BACT LIMITS BASED ON THE FALSE BELIEF THAT THE ELM ROAD PERMIT LIMITS WERE FOR A CFB BOILER.

The Proposed Permit contains a BACT limit for sulfuric acid mist (SAM) of 0.0035 lb/MMBtu. Proposed Permit p. 4 ¶ h. Sierra Club commented that the KDAQ must consider previously permitted BACT limits in a top-down BACT process and that the Elm Road IGCC unit has a permitted SAM BACT limit of 0.0005 lb/MMBtu. *See* Response to Comments at p. 55. This represents a limit 85% lower than the limit in the Proposed Permit. However, KDAQ utterly refused to consider the lower Elm Road BACT limit based on KDAQ's false belief that "the Elm Road facility is a CFB, not a gasifier, and is not an appropriate 'like facility' for consideration of appropriate emissions from Cash Creek." *Id.* KDAQ is wrong. The Elm Road facility is not a CFB. It was permitted for two supercritical pulverized coal boilers and one IGCC unit. The SAM BACT limit referenced in Sierra Club's comments is for the IGCC unit. *See* Wisconsin Air Pollution Control Construction Permit 03-RV-166 § I.II.11.1. ("The [SAM] emissions may not exceed 0.0005 pound per million Btu, (BACT).") (Attached as Exhibit E). A 0.0005 lb/MMBtu limit, based on the permitted limit for the Elm Road IGCC unit, is presumed to be BACT for the Cash Creek units because the applicant has not demonstrated that it is not technologically feasible, not cost effective, or that it would cause unique adverse energy or environmental collateral impacts. *NSR Manual* at B.24; *Newmont Nevada Energy Investments, LLC, TS Power Plant,* PSD Appeal No. 05-04, Slip Opinion at 16 (EAB Dec. 21, 2005). In short, neither the applicant nor KDAQ offers evidence refuting that the Cash Creek units can achieve this lower BACT limit for SAM. Therefore, the Administrator must object to the Permit as containing an erroneous SAM BACT limit.

VII. KDAQ FAILED TO RESPOND TO COMMENTS REGARDING THE CORRECT EMISSION RATE TO USE FOR MODELING MATERIAL HANDLING AND STORAGE PROCESS EMISSIONS.

Sierra Club's comments to the KDAQ stated that: "If the modeling did not use the maximum theoretical emission rate for each source, the agency must reject the modeling demonstration and require the applicant to resubmit proper modeling. *See NSR Manual* at C.45-46." Letter from Meleah Geertsma to James Morse, KDAQ, at p. 13 (June 29, 2007) (Exhibit B). Sierra Club's comments pointed out that modeling conducted to determine compliance with air standards and increment limits in support of a permit must be done at maximum allowable emission rates. *NSR Manual* at C.42-C.46. Unless there is an enforceable short-term limit on emissions, modeling for short-term standards (like 24 hour PM) must be done assuming maximum theoretical throughput for coal handling and maximum emissions for coal pile wind erosion. *See NSR Manual* C.45 ("For both NAAQS and PSD increment compliance demonstrations, the emission rate for the proposed new source or modification must reflect the maximum allowable operating conditions as expressed by the federally enforceable *emissions limit, operating level* and *operating factor* for each applicable pollutant and averaging time." (emphasis original)). This was not done for the Cash Creek permit. Rather, the annual presumed throughput and annual average coal pile erosion emissions were used for determining compliance with 24-hour PM standards. *See e.g.,* Permit Application at p. 5-23 (mean annual wind speed of 7 mph used, rather than maximum 24-hour mean wind speed). This is a material error in the permit requiring an objection. Moreover, KDAQ's failure to respond to Sierra Club's comment on this point is also an error that requires an objection by the Administrator. *See e.g., In re Midwest Generation, LLC, Waukegan Generating Station,* Order Responding to Petition to Object at p. 4 (Adm'r September 22, 2005) (objecting to proposed permit and holding that where a petitioner raises an issue in the public comment period, the permitting agency is required to respond) (*citing Home Box Office v. FCC,* 567 F.2d 9, 35 (D.C. Cir. 1977).

Dated this 31st day of January, 2008.

Attorneys for Sierra Club
GARVEY MCNEIL & MCGILLIVRAY, S.C.
David C. Bender

SIERRA CLUB
Bruce E. Nilles

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of the Proposed Operating Permit for the Cash Creek Generation Station in Henderson County, Kentucky.	Source I.D. No. 21-101-00134 Permit No. V-07-017
Proposed by the Kentucky Environmental Protection Cabinet Department for Environmental Protection Division for Air Quality on November 30, 2007.	

CERTIFICATE OF SERVICE

STATE OF WISCONSIN)
) ss
COUNTY OF DANE)

I make this statement under oath and based on personal knowledge. On this day I caused to be served upon the following persons a copy of Sierra Club's Petition to the United States Environmental Protection Agency In the Matter of the Proposed Operating Permit for the Cash Creek Generation, LLC, Cash Creek Generating Station in Henderson, Kentucky, via Certified Mail, Return Receipt Requested:

Stephen L. Johnson
US EPA Administrator
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Environment and Public Protection Cabinet
Department for Environmental Protection
Division of Air Quality
803 Shenkel Lane
Frankfurt, KY 40601

Cash Creek Generation LLC
Cash Creek Generation Station
4350 Brownsboro Road, Suite 110
Louisville, KY 40207

Dated : January 31, 2008

Laura Boyd
Laura Boyd

Signed and sworn to before me
This 31st day of January, 2008.

Notary Public, State of Wisconsin
My commission is permanent.

Commonwealth of Kentucky
Environmental and Public Protection Cabinet
Department for Environmental Protection
Division for Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601
(502) 573-3382

Final

AIR QUALITY PERMIT
Issued under 401 KAR 52:020

Permittee Name:	**Cash Creek Generation, L.L.C.**
Mailing Address:	**4350 Brownsboro Road, Suite 110, Louisville, Ky 40207**
Source Name:	**Cash Creek Generation Station**
Mailing Address:	**4350 Brownsboro Road, Suite 110, Louisville, Ky 40207**
Source Location:	**Kentucky State Highway 1078 in Henderson County**
Permit Number:	**V-07-017**
Source A. I. #:	**40285**
Activity #:	**APE20060001**
Review Type:	**Title V/PSD NSR, NSPS**
Source ID #:	**21-101-00134**
ORIS Code:	**56107**
Regional Office:	**Owensboro** **3032 Alvey Park Drive W., Suite 700** **Owensboro, KY 42303-2191** **(270) 687-7304**
County:	**Henderson**
Application Complete Date:	**March 29, 2007**
Issuance Date:	**January 17, 2008**
Revision Date:	
Expiration Date:	**January 17, 2013**

John S. Lyons, Director
Division for Air Quality

EXHIBIT A

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SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

p) Pursuant to 40 CFR 60.13(h), for the continuous monitoring systems the owner(s) or operator(s) shall reduce all data to one-hour averages. The one-hour averages shall be computed from four or more data points equally spaced over each one-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent oxygen). All excess emissions shall be converted into units of the applicable standard using the applicable conversion procedures specified. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used to specify the applicable emission standard.

q) Pursuant to 401 KAR 52:020, Section 26, the permittee shall monitor the hours of operation and fuel consumption of each emission unit on a daily basis.

r) Pursuant to 401 KAR 52:020, Section 26, for the particulate and PM_{10} monitoring the permittee shall develop emission factors during the performance test. The permittee shall record the synthesis gas heating value and the consumption of each fuel burned. On a daily basis, the permittee shall calculate the emission rate for particulate/particulate/matter$_{-10}$ using the fuel consumption, heating value of fuel, and emission factor developed during the most recent performance test.

s) The permittee shall use Nitrogen Oxides (NO_x) Continuous Emissions Monitors (CEMs) as continuous compliance determination methods consistent with 40 CFR 64.4(d) (CAM) for those specific parameters, and to demonstrate compliance with Best Available Control Technology (BACT) limits contained in this permit, as applicable.

5. **Specific Record Keeping Requirements:**

a) Pursuant to 401 KAR 59:005, Section 3(4), the permittee of the source shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

b) Pursuant to 401 KAR 59:005, Section 3(2), the permittee of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility, any malfunction of the air pollution control equipment; or any period during which a continuous monitoring system or monitoring device is inoperative. The record shall also include the type and quantity of fuel fired and the estimated emissions during each episode.

c) Records, including those documenting the results of each compliance test and all other records and reports required by this permit, shall be maintained for five (5) years pursuant to 401 KAR 52:020.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

j) Pursuant to 40 CFR 60.49Da (l) and (m), the permittee of an affected facility demonstrating compliance with an output-based standard under 40 CFR 60.42Da, 40 CFR 60.43Da, 40 CFR 60.44Da, or 40 CFR 60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B and procedure 1 of appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

k) Pursuant to 40 CFR 60.49Da (p) the permittee of an affected facility demonstrating compliance with an Mercury limit in 40 CFR 60.45Da shall install and operate a continuous emission monitoring system (CEMS) to measure and record the concentration of Mercury in the exhaust gases from each stack according to the requirements in 40 CFR 60.45Da, paragraphs (p)(1) through (p)(3) of 40 CFR 60 Subpart Da. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the permittee may install, certify, maintain, operate and quality-assure the data from a Mercury CEMS according to 40 CFR 75.10 of this chapter and appendices A and B to 40 CFR part 75 , in lieu of following the procedures in 40 CFR 40 CFR 60.45Da, paragraphs (p)(1) through (p)(3) of 40 CFR 60 Subpart Da, and mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of 40 CFR 60 Subpart Da.

l) Pursuant to 40 CFR 60.49Da (s) the permittee shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The permittee shall comply with the requirements in the plan. The plan must address the requirements in paragraphs (s)(1) through (6) of that section.

m) Pursuant to 40 CFR 60.13(d)(1), the owner(s) and operator(s) of all continuous monitoring systems shall perform appropriate calibration checks and zero and span adjustments in accordance with a written procedure at least once daily, in accordance with requirements specified in 40 CFR 60.13(d)(1).

n) Pursuant to 40 CFR 60.13(e), except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements which involves one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen (15) minute period.

o) Pursuant to 40 CFR 60.13(f), all continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the emissions unit are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of 40 CFR 60 Appendix B shall be used.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to 40 CFR 60.49Da (c) 1, the permittee shall install, calibrate, maintain, and operate a nitrogen oxides continuous emissions monitor (CEM) system or, if the permittee has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of 40 CFR Part 75 and is continuing to meet the ongoing requirements of 40 CFR Part 75, that CEMS shall be used to meet the requirements of this permit, except that the permittee shall also meet the requirements of 40 CFR 60.51Da. Data reported to meet the requirements of 40 CFR 60.51Da shall not include data substituted using the missing data procedures in subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75.

d) Pursuant to 40 CFR 60.49Da (d) the permittee of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

e) Pursuant to 40 CFR 60.49Da (e) the continuous monitoring systems under paragraphs (b), (c), and (d) of 40 CFR 60 Subpart Da are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

f) Pursuant to 40 CFR 60.49Da (f) (2) the permittee shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the permittee shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in 40 CFR 60.49Da paragraph (h) of 40 CFR 60 Subpart Da.

g) Pursuant to 40 CFR 60.49Da (h), when it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in 40 CFR 60.49Da paragraph (f) of 40 CFR 60 Subpart Da, the permittee shall use the reference methods and procedures as specified in 40 CFR 60.49Da paragraph (h). Acceptable alternative methods and procedures are given in 40 CFR 60.49Da paragraph (j) of 40 CFR 60 Subpart Da.

h) Pursuant to 40 CFR 60.49Da (i), the permittee shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d). Acceptable alternative methods and procedures are given in paragraph 40 CFR 60.49Da (j) of 40 CFR 60 Subpart Da.

i) Pursuant to 40 CFR 60.49Da (j), the permittee may use the following alternatives of 40 CFR 60.49Da (j) (1),(2),(3) & (4) as alternatives to the reference methods and procedures specified in 40 CFR 60 Subpart Da.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. **Testing Requirements:**

a) Pursuant to 401 KAR 59:005, Section 2 the permittee shall demonstrate compliance for each turbine while firing natural gas with the applicable emission standards within sixty (60) days after achieving the rated capacity at which each turbine will be operated, but not later than 180 days after initial startup of each turbine, in accordance with the requirements in 401 KAR 50:045

b) Pursuant to 401 KAR 59:005, Section 2 the permittee shall demonstrate compliance for each turbine while firing synthesis gas with the applicable emission standards within sixty (60) days after achieving the rated capacity of each gasifier, but not later than 180 days after initial startup of gasifiers, in accordance with the requirements in 401 KAR 50:045

c) The permittee shall determine the opacity of emissions from the stack by U.S. EPA Reference Method 9 weekly, or more frequently if requested by the Division.

d) If no additional stack tests are performed prior to the third year after demonstrating compliance, the permittee shall conduct performance tests for particulate emissions and H_2SO_4 with the allowable standards while firing synthesis gas. See Section D for further requirements.

4. **Specific Monitoring Requirements:**

a) Pursuant to 401 KAR 60:005, Section 3(1)(c) incorporating by reference 40 CFR 60 Da; 401 KAR 52:020, Section 26; and 401 KAR 59:005, Section 4, the permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems for measuring the sulfur dioxide emissions, nitrogen oxides emissions, mercury, and either oxygen or carbon dioxide emissions. Additionally, a CEM system shall be installed, calibrated, maintained, and operated for measuring oxygen or carbon dioxide levels of the flue gases at each location where sulfur dioxide or nitrogen emissions are monitored. The permittee shall ensure the continuous emission monitoring systems are in compliance with the requirements of 401 KAR 59:005, Section 4.

b) Pursuant to 40 CFR 60.49Da (b), and 40 CFR 75, to meet the monitoring requirement for sulfur dioxide the permittee shall use a continuous emission monitor (CEM). The sulfur dioxide CEM system shall be used as the indicator of continuous compliance with the sulfur dioxide emission limits. Excluding startup and shutdown periods, if any 3-hour rolling average exceeds the sulfur dioxide emission limitation, the permittee shall initiate an investigation of the cause of the exceedance and complete necessary control device/process/CEM repairs or other corrective actions as soon as practicable.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

f) Pursuant to 40 CFR 60 Subpart Da, and 401 KAR 51:017, filterable particulate/PM_{10} emissions shall not exceed 0.0085 lb/MMBtu during any rolling three-hour average period when firing synthesis gas. Total particulate/PM_{10} emissions shall not exceed 0.0217 lb/MMBtu during any rolling three-hour average period when firing synthesis gas. The lb/MMBtu level of particulate emissions shall be demonstrated by stack test, then calculated based on the emission factor derived during the test, fuel consumption data, fuel heat input, and fuel heat content [see specific monitoring requirements].

g) Pursuant to 40 CFR 60 Subpart Da, and 401 KAR 51:017, Total particulate/PM_{10} emissions shall not exceed 0.0161 lb/MMBtu during any rolling three-hour average period when firing natural gas. filterable particulate/PM_{10} emissions shall not exceed 0.0063 lb/MMBtu during any rolling three-hour average period when firing natural gas The lb/MMBtu level of particulate emissions shall be demonstrated by stack test, then calculated based on the emission factor derived during the test, fuel consumption data, fuel heat input, and fuel heat content [see specific monitoring requirements].

h) Pursuant to 401 KAR 51:017, sulfuric acid mist (H_2SO_4) emissions shall not exceed 0.0035 lb/MMBtu during any rolling three-hour average period when firing synthesis gas. The lb/MMBtu level of sulfuric acid mist emissions shall be demonstrated by stack test, then calculated based on the emission factor derived during the test, fuel consumption data, fuel heat input, and fuel heat content.

i) Pursuant to 401 KAR 51:017, sulfuric acid mist (H_2SO_4) emissions shall not exceed 0.0001 lb/MMBtu when firing natural gas. The lb/MMBtu level of sulfuric acid mist emissions shall be assured by firing pipeline quality natural gas.

j) Pursuant to 40 CFR 60.45Da (b), mercury emissions shall not exceed 20 $\times 10^{-6}$ lb/MWh or 0.020 lb/GWh on an output basis. This Mercury emission limit is based on a 12-month rolling total using the procedures in 40 CFR 60.50Da (g).

k) Pursuant to 40 CFR 60.48Da, the particulate matter emission standards under 40 CFR 60.42Da, the nitrogen oxides emission standards under 40 CFR 60.44Da, and the Mercury emission standards under 40 CFR 60.45Da, apply at all times except during periods of startup, shutdown, or malfunction. Pursuant to 40 CFR 60.48Da, the SO_2 emission standards under 40 CFR 60.43Da, apply at all times except during periods of startup, shutdown, or emergency.

l) Pursuant to 401 KAR 52:020, duration of startup, shutdown and malfunction periods for the gasifier(s) are limited to 48 hours per occurrence with 3 annual occurrences for 2 gasifiers and with 29 annual occurrences for 1 gasifier. The requirement for duration and number of occurrences is waived during the first year after the initial demonstration of compliance. Startup and shutdown shall be performed consistent with the SSM plan submitted on December 4, 2006.

m) Consistent with 40 CFR 60 Subpart Da, BACT emission limits are based upon heat input to the combustion turbines.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) The average heat input to each turbine shall not exceed 2114 MMBtu/hour for natural gas at ISO standard day conditions on a three hour rolling average. [Pursuant to 401 KAR 51:017, Prevention of significant deterioration of air quality].

c) Pursuant to 401 KAR 51:017, the permittee shall install control devices required to meet BACT.

d) Pursuant to 40 CFR 60, Subpart Da, the combined cycle gas turbine shall be designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis.

2. **Emission Limitations:**

a) Pursuant to 40 CFR 60 Subpart Da, and 401 KAR 51:017, nitrogen oxides emission level in the exhaust gas shall not exceed 0.0331 lb/MMBtu during any rolling 24-hour average period (approximately 5 ppmvd @ 15 % oxygen (O_2)) when firing synthesis gas. The nitrogen oxides emission level in the exhaust gas shall not exceed 0.0246 lb/MMBtu during any rolling 24-hour average period when firing natural gas. Additionally, the permittee shall keep records of the quantity of each fuel used and the actual NOx and CO emissions during such periods. The ppm level of nitrogen oxides (at ISO standard conditions) and lb/MMBtu shall be demonstrated by stack test, and measured with use of a continuous emission monitor (CEM).

b) Pursuant to 401 KAR 51:017, the carbon monoxide emission level in the exhaust gas shall not exceed 0.0485 lb/MMBtu during any rolling 24-hour average period when firing syn-gas. The carbon monoxide emission level in the exhaust gas shall not exceed 0.0449 lb/MMBtu during any rolling 24-hour average period when firing natural gas. Additionally, the permittee shall keep records of the quantity of each fuel used and the actual NOx and CO emissions during such periods. The ppm level of carbon monoxide and lb/MMBtu shall be demonstrated by stack test, and measured with use of a continuous emission monitor (CEM).

c) Pursuant to 40 CFR 60 Subpart Da, and 401 KAR 51:017, when firing synthesis gas, the sulfur dioxide emission level in the exhaust gas shall not exceed 0.0158 lb/MMBtu based on any rolling three-hour average period (3.8 ppmvw @ 15% oxygen (O_2)). The level of sulfur dioxide converted to lb/MMBtu shall be demonstrated by stack test, and measured with use of a continuous emission monitor (CEM).

d) Pursuant to 401 KAR 51:017, the sulfur dioxide emission level in the exhaust gas shall not exceed 0.0006 lb/MMBtu when firing natural gas.

e) Pursuant to 40 CFR 60.42Da (b) emissions from this unit shall not exceed twenty (20) percent opacity (6-minute average), except for one 6-minute period per hour of not more than (27) percent opacity.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emissions Units: 01 (01) & 02 (02) – Coal gasifiers and Synthesis/Natural Gas-Fired Combined Cycle Combustion Turbines [Emissions Units: HRSG-1 & HRSG-2]

Description:

2917 MMBtu/hr rated heat input capacity to each gasifier.
2114 MMBtu/hr rated heat input capacity to each combustion turbine.
Approximately 770 MW nominal power capacity with a net output of 630 MW (both turbines and recovery steam generators).
GE 7FB synthesis gas (primary) or natural gas (secondary) fired combined cycle combustion turbine equipped with diluent nitrogen injection.
Control Equipment: equipped with Selective Catalytic Reduction (SCR) for NOx, Nitrogen Dilution
Fuel pretreatment: Acid Gas Scrubber and Carbon Absorption
Construction commenced: estimated - 2008

APPLICABLE REGULATIONS:
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982;

401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Generating Units for which construction is commenced after September 18, 1978.

401 KAR 59:016. New electric utility steam generating units. (State-only requirements)

401 KAR 51:160, NOx requirements for large utility and industrial boilers; 401 KAR 51:210, CAIR NOx annual trading program, and 401 KAR 220 CAIR NOx ozone trading program.

401 KAR 52:060, Acid rain permits, incorporating provisions as codified in 40 CFR Parts 72 to 78

(Proposed, not yet applicable) 401 KAR 60:020. Mercury Budget Trading Program. Promulgated to meet the requirements of 40 CFR 60 Subpart HHHH—Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units

401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances

40 CFR Part 75, Continuous Emission Monitoring;

40 CFR Part 64, Compliance Assurance Monitoring (CAM)

1. **Operating Limitations:**

a) Synthesis gas (mainly consists of carbon monoxide and hydrogen gas), and natural gas shall be the sole fuels fired in the turbines. [Pursuant to 401 KAR 51:017, Prevention of significant deterioration of air quality].

SECTION A - PERMIT AUTHORIZATION

Pursuant to a duly submitted application the Kentucky Division of Air Quality hereby authorizes the operation of the equipment described herein in accordance with the terms and conditions of this permit. This permit has been issued under the provisions of Kentucky Revised Statutes Chapter 224 and regulations promulgated pursuant thereto.

The permittee shall not construct, reconstruct, or modify any affected facilities without first submitting a complete application and receiving a permit for the planned activity from the permitting authority, except as provided in this permit or in 401 KAR 52:020, Title V Permits.

Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by this Cabinet or any other federal, state, or local agency.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

d) Pursuant to 401 KAR 52:020, Section 26, records of the hourly synthesis gas and/or natural gas (million standard cubic feet) combusted shall be maintained. Records shall be maintained to show that synthesis gas and natural gas are the sole fuels burned in the turbine.

e) Pursuant to 401 KAR 52:020, Section 26, the permittee shall maintain a weekly log of all hours of operation of each turbine, for any consecutive twelve (12) month period.

f) Pursuant to 40 CFR 60.52Da the permittee of an affected facility subject to the emissions limitations in 40 CFR 60.45Da shall provide notifications in accordance with 40 CFR 60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of 40 CFR 60.7(f).

g) Pursuant to 401 KAR 52:020, Section 26, the permittee shall maintain a log of all Method 9 opacity readings.

6. **Specific Reporting Requirements:**

a) Pursuant to 40 CFR 60.51Da(a) for sulfur dioxide, nitrogen oxides, particulate matter, and mercury emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be submitted to the Frankfort Central Office.

b) Pursuant to 40 CFR 60.51Da(b) for sulfur dioxide and nitrogen oxides the following information shall be reported to the Regional/Central Office for each 24-hour period consistent in accordance with the requirements of 40 CFR 60.51Da (b) items 1 through 9.

c) Pursuant to 40 CFR 60.51Da(c) if the minimum quantity of emission data as required by 40 CFR 60.49Da is not obtained for any 30 successive boiler operating days, the permittee shall submit information consistent with the requirements of 40 CFR 60.51Da (c) items 1 through 5 obtained under the requirements of 40 CFR 60.48Da (h) to the Regional Office for that 30-day period.

d) Pursuant to 40 CFR 60.51Da (d) if any standards under 40 CFR 60.43Da are exceeded during emergency conditions because of control system malfunction, the permittee of the affected facility shall submit a signed statement consistent with the requirements of 40 CFR 60.51Da (d) items 1 through 4.

e) Pursuant to 40 CFR 60.51Da(e) if fuel pretreatment credit toward the sulfur dioxide emission standard under 40 CFR 60.43Da is claimed, the permittee of the affected facility shall submit a signed statement consistent with the requirements of 40 CFR 60.51Da (e) items 1 and 2.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

f) Pursuant to 40 CFR 60.51Da(f) for any periods for which sulfur dioxide or nitrogen oxides emissions data are not available, the permittee of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

g) The permittee shall the report the information required by 40 CFR 60.51Da (g) items 1 through 5 to Regional Office on an annual basis.

h) Pursuant to 40 CFR 60.51Da (h) the permittee of the affected facility shall submit a signed statement as required by 40 CFR 60.51Da (h) items 1 through 4 on an annual basis.

i) Pursuant to 40 CFR 60.51Da(i) for the purposes of the reports required under 40 CFR 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR 60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Regional Office each calendar quarter.

j) Pursuant to 40 CFR 60.51Da (j) the permittee of an affected facility shall submit the written reports required under 40 CFR 60 Subpart Da and 40 CFR 60 Subpart A to the Regional Office semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

k) Pursuant to 40 CFR 60.51Da(k) the permittee of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or mercury in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of 40 CFR 60 Subpart Da. The format of each quarterly electronic report shall be coordinated with the Regional Office. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the permittee shall coordinate with the Regional Office to obtain their agreement to submit reports in this alternative format.

l) Pursuant to 401 KAR 59:005, Section 3, minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

1) The magnitude of the excess emissions computed in accordance with the 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the emissions unit. The nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

3) The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

m) Pursuant to 401 KAR 52:020, Section 26, for nitrogen oxides, excess emissions are defined as any 24 hour period during which the average emissions (arithmetic average) exceed the applicable nitrogen oxides emission standard. These periods of excess emissions shall be reported quarterly.

n) Pursuant to 401 KAR 52:020, Section 26, excess emissions of sulfur dioxide are defined as any 3-hour period during which the average sulfur dioxide emissions as indicated by continuous emission monitoring, or the sulfur content (or as otherwise required in an approved custom fuel sulfur monitoring plan) of the fuel being fired in the gas turbine(s) exceeds the limitations set forth in Subsection 2, Emission Limitations. These periods of excess emissions shall be reported quarterly.

o) Pursuant to 401 KAR 52:020, Section 26, for carbon monoxide, excess emissions are defined as any 24 hour period during which the average emissions (arithmetic average of three contiguous one hour periods) exceed the applicable carbon monoxide emission standard. These periods of excess emissions shall be reported quarterly.

p) Pursuant to 401 KAR 52:020, Section 26, for mercury excess emissions are defined as an annual period during which emissions exceed the applicable mercury emission standard.

q) Pursuant to 401 KAR 52:020, Section 26, for sulfuric acid mist (H_2SO_4) excess emissions are defined as any 3 hour period during which the average emissions exceed the applicable emission standard. These periods of excess emissions shall be reported quarterly.

SECTION B - EMISSION POINTS, EMISSIONS UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. Specific Control Equipment Operating Conditions:

a) The SCR and diluent injection control measure for nitrogen oxides emissions and the acid gas scrubbing system for sulfur dioxide emissions shall be operated in accordance with manufacturer's design specifications and/or good engineering practices. The permittee shall implement good combustion control and use clean, low sulfur/low ash syngas as fuel. Natural gas may be fired at any time, as long as the annual usage does not exceed the operating limits in **Operating Limitations** (c) and (e)

b) See Section E for further requirements.

SECTION B -EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions unit: 03 (03) - Unit 3 Indirect Heat Exchanger (AUXB)

Description:
Natural gas-fired indirect heat exchanger
Maximum continuous rating: 278.8 MMBtu/hr
Control Equipment: low NOx burners
Construction commenced: estimated - 2009

Applicable Regulations:

401 KAR 59:015, New indirect heat exchangers with a capacity greater than 250 MMBtu /hour and commenced after August 17, 1971

401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Db, Standards of Performance for industrial-commercial-institutional steam generating units, applies to each steam generating unit commenced after June 19, 1984 that has a maximum design heat input capacity greater than 100MMBtu/hr.

401 KAR 51:160. NOx requirements for large utility and industrial boilers; including 401 KAR 51:220, CAIR NOx ozone trading program after 2009.

401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982

1. **Operating Limitations:**

   The auxiliary boiler shall only operate during gasifier start-up periods. The auxiliary boiler shall not operate more than 500 hours per twelve (12) consecutive months [401 KAR 51:001, Section 1 (25)].

2. **Emission Limitations:**

   a) Pursuant to 401 KAR 59:015, Section 4(1)(b), 40 CFR 60.43b(h) and 401 KAR 51:017, particulate emissions shall not exceed 0.007 lb/MMBtu based on a three-hour average.

   b) Pursuant to 401 KAR 59:015, Section 4(2) emissions shall not exhibit greater than twenty (20) percent opacity except:

   1) That, for indirect heat exchangers with heat input capacity of 250 MMBtu per hour or more, a maximum of twenty-seven (27) percent opacity shall be permissible for not more than one (1) six (6) minute period in any sixty (60) consecutive minutes.

   2) For emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations

SECTION B -EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to 401 KAR 59:015, Section 5(2), 40 CFR 60.42b(k) and 401 KAR 51:017, sulfur dioxide emissions shall not exceed 0.006 lb/MMBtu based on a twenty four-hour average. Compliance is assured through combustion of natural gas only.

d) Pursuant to 401 KAR 59:015, Section 6(1), 40 CFR 60.44b(a) and 401 KAR 51:017, nitrogen oxides emissions shall not exceed 0.036 lb/MMBtu based on a twenty four-hour average.

3. **Testing Requirements:**

a) Pursuant to 401 KAR 59:005, Section 2 and 401 KAR 59:015, Section 8 the permittee shall conduct performance tests for NOx, CO, and PM/PM_{10} to demonstrate compliance with the applicable emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.

b) See Section D.

4. **Specific Monitoring Requirements:**

a) Pursuant to 401 KAR 52:020, Section 26, the permittee shall monitor the hours of fuel combusted on a daily basis during each twelve (12) consecutive months.

b) Pursuant to 401 KAR 52:020, Section 26, to demonstrate continuing compliance with the BACT determination, monitoring of operations shall consist of fuel supplier certification. The fuel supplier certification shall include the name of the natural gas supplier, a statement of the natural gas heating value, weight percent sulfur and that the natural gas complies with the specifications under the definition for natural gas in 40 CFR 60.40b.

c) Pursuant to 401 KAR 51:160, the permittee shall monitor the total NOx emissions during each NOx control period as specified in 40 C.F.R. 96.70 to 96.76.

5. **Specific Record Keeping Requirements:**

a) Pursuant to 401 KAR 59:005, Section 3(4), the permittee of the indirect heat exchanger shall maintain a file of all measurements and performance testing measurements required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

b) Pursuant to 401 KAR 59:005, Section 3(2), the permittee of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility.

c) The permittee shall maintain the results of all compliance tests.

d) The permittee shall maintain records of hours of operation and natural gas usage during each twelve (12) consecutive months.

e) Pursuant to 401 KAR 59:005, Section 3 (4), the permittee of the indirect heat exchanger shall maintain a file of all measurements, including monthly natural gas usage. The permittee shall maintain a file of the fuel supplier certification; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection. The file shall be retained for at least five (5) years following the date of such measurements, maintenance, reports, and records.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 60:005, Section 3(1)(d), the permittee shall follow the applicable reporting requirements and recordkeeping requirements specified in 40 CFR 60.49b.

b) See Section F for further requirements.

7. Specific Control Equipment Operating Conditions:

None.

SECTION B -EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 04 (04) - Unit 4 (Flare)

Description:

Three continuous pilots rated at 490 SCF/hr natural gas for pilot flame
Construction commenced: expected 2009

Applicable Regulations:

401 KAR 63:015, Flares

401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982

1. **Operating Limitations:**

   a) Synthesis gas shall only be vented to the flare during periods of startup, shutdown and malfunction of the thermal oxidizer. Emissions from the flare are not eligible for relief with compliance under 401 KAR 50:055, as the normal operation of the flare occurs during periods of startup, shutdown and malfunction of other process units.

   b) Pursuant to 401 KAR 51:017, the permittee shall use good flare design consistent with the requirements established in 40 CFR 63.11.

2. **Emission Limitations:**

   a) Pursuant to 401 KAR 51:017, the flare shall be designed for and operated with no visible emissions, except for periods not exceeding a total of 5 minutes during any 2 consecutive hours.
   b) Pursuant to 401 KAR 63:015, Section 3, the opacity of visible emissions the flare listed above shall not exceed 20% for more than 3 minutes in any one day.

3. **Testing Requirements:**

   The permittee shall perform Method 22 testing for visible emissions during any period of flaring greater than one hour, for the duration of each syngas venting episode. The permittee shall observe and record in a log the following information:

   1. The total duration of visible emission incident;
   2. The cause of the abnormal emissions; and
   3. Any corrective actions taken.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. Specific Monitoring Requirements:

a) Pursuant to 401 KAR 52:020, Section 26, the flare shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

b) See 3. Testing Requirements above.

5. Specific Recordkeeping Requirements:

a) Pursuant to 401 KAR 52:020, Section 26, the permittee shall maintain a log of the dates and times of each Method 22 test and either the results of the test or reasons for not performing a Method 22 test.

b) Pursuant to 401 KAR 52:020, Section 26, the permittee shall maintain a log of each period of flaring, and the quality of synthesis gas being flared, i.e. combustion ready, untreated or partially treated by the sulfur removal units and/or acid gas system.

6. Specific Reporting Requirements:

Pursuant to 401 KAR 52:020, Section 26, duration, amounts and quality of syngas flared shall be reported as required by Section F. of this permit.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 51:017, Prevention of significant deterioration of air quality, the permittee shall comply with best available control technology with use of good flare design.

b) Permittee shall demonstrate good flare design by complying with the requirements of 40 CFR 63.11, or by an alternative demonstration approved by the Division.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 05 (05) Unit 5 (Acid Gas Removal and Thermal Oxidizer)

Description:

Production areas Acid Gas Removal System (AGR) and Tail Gas Treatment Unit will have a thermal oxidizer (TO) as a control device
Thermal Oxidizer - tail gas treatment
Construction commenced: expected 2009

Applicable Regulations:
401 KAR 59:105, New Process Gas Streams commenced after June 6, 1979

401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982

1. **Operating Limitations:**

a) Pursuant to 401 KAR 51:017 and 401 KAR 50:055, Section 2(5), the permittee shall operate the thermal oxidizer at all times the AGR systems is in operation.

b) The average combustion temperature of the Thermal Oxidizer (TO) shall not be operated below 1100 degrees Fahrenheit, based on a one-hour average. Upon completion of a performance test, the thermal oxidizer shall not be operated more than 28 degrees Celsius (50 degrees Fahrenheit) below the average combustion temperature limit established during the most recent performance test.

2. **Emission Limitations:**

a) Pursuant to 401 KAR 59:105 Section 3, no person shall cause, suffer, allow or permit the emission of hydrogen sulfide in a process gas stream to exceed ten (10) grains per 100 dscf (165 ppm by volume) at zero percent oxygen except that sources whose combined process gas stream emission rate totals less than two (2) tons per day of hydrogen sulfide shall either reduce such emissions by eighty-five (85) percent or control such emissions such that hydrogen sulfide in the gas stream emitted into the ambient air does not exceed ten (10) grains per 100 dscf (165 ppm by volume) at zero percent oxygen.

b) Pursuant to 401 KAR 59:105, Section 4, no person shall cause, suffer, allow or permit the emission of sulfur dioxide in a process gas stream to exceed 28.63 grains per 100 dscf (250 ppm by volume) at zero percent oxygen except that sources whose combined process gas stream emission rate totals less than four (4) tons per day of sulfur dioxide shall reduce such emissions by eighty-five (85) percent.

c) Pursuant to 401 KAR 51:017, the emissions of SO_2 from the sulfur recovery unit shall not exceed 100 ppm by volume (dry basis) at 0% oxygen on a three hour basis except during startup, shutdown and malfunction.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. **Testing Requirements:**

a) Pursuant to 401 KAR 59:005, Section 2 the permittee shall conduct performance tests for the inlet and outlet concentrations of H_2S and SO_2 to demonstrate compliance with the BACT emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.

b) The permittee shall use the data collected during the performance test to calculate and record the average combustion temperature. This average combustion temperature minus 28 degrees Celsius (50 degrees Fahrenheit) shall become the minimum operating set point of the thermal oxidizer.

4. **Specific Monitoring Requirements:**

a) In accordance with 401 KAR 52:020, Section 26, the permittee must monitor the temperature in the firebox of the thermal oxidizer or immediately downstream of the firebox before any substantial heat exchange occurs. Compliance shall be demonstrated by monitoring and recording the combustion temperature a minimum of recording the measured value at least once every 15 minutes. The thermocouple shall have an accuracy of the greater of 0.75 percent of the temperature measurement expressed in degrees Celsius or $\pm 2.5^{o}C$.

b) In accordance with 401 KAR 52:020, Section 26, the permittee must perform an electronic calibration semi-annually (on a calendar year basis) of the convertor/temperature readout device. Following the electronic calibration, a thermocouple validation check must be conducted in which the readout device of a second or redundant thermocouple must yield a reading within 30 degrees Fahrenheit of each other.

c) In accordance with 401 KAR 52:020, Section 26, the permittee must conduct an accuracy audit consisting of an electronic calibration of the convertor/temperature readout device and validation of the thermocouple any time the thermocouple exceeds the manufacturer's specified maximum operating temperature range or install a new or lab certified thermal couple.

d) In accordance with 401 KAR 52:020, Section 26, the permittee must at least monthly, inspect components for integrity and electrical connections for continuity, oxidation, and galvanic corrosion.

e) Pursuant to 401 KAR 51:017 and 40 CFR 75, to meet the monitoring requirement for sulfur dioxide the permittee shall use a continuous emission monitor (CEM). The sulfur dioxide CEM system shall be used as the indicator of continuous compliance with the sulfur dioxide emission limits. The CEM may be installed either prior to the thermal oxidizer or on the exhaust stack. Excluding startup and shutdown periods, if any 3-hour rolling average exceeds the sulfur dioxide emission limitation, the permittee shall initiate an investigation of the cause of the exceedance and complete necessary process/CEM repairs or other corrective actions as soon as practicable.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

f) In accordance with 401 KAR 52:020, Section 26, the permittee shall perform a qualitative visual observation of the opacity of emissions from the thermal oxidizer on a weekly basis and maintain a log of the observations. If visible emissions from the thermal oxidizer are seen, the permittee shall determine the opacity of emissions by Reference Method 9 and initiate an inspection of the thermal oxidizer and the entire process making any necessary repairs.

5. **Specific Recordkeeping Requirements:**

a) In accordance with 401 KAR 52:020, Section 26, the permittee shall maintain records of the following information for the thermal oxidizer:

i. The design and/or manufacturer's specifications or equivalent document.
ii. The operational procedures and preventive maintenance records.
iii. The calibration records, thermocouple validation checks, and any subsequent accuracy audits.
iv. Maintain a record (electronically or by strip chart) of the average combustion chamber temperature limit established during the most recent performance test and all relevant supporting data.
v. All periods (during periods of operations) during which the combustion chamber temperature of the thermal oxidizer is more than 28 degrees Celsius (50 degrees Fahrenheit) below the average combustion chamber temperature of the thermal oxidizer during the most recent performance test which demonstrated compliance. Each occurrence shall be considered a deviation from permit requirements.
vi. During all periods of operation(one hour rolling average) of the thermal oxidizer in which the combustion chamber temperature of the thermal oxidizer is more than 28 degrees Celsius (50 degrees Fahrenheit) below the average combustion chamber temperature of the thermal oxidizer during the most recent performance test which demonstrated compliance, or other malfunction of the thermal oxidizer, a daily log of the following information shall be kept:
  a. Whether any air emissions were visible from the facilities associated with the thermal oxidizer.
  b. Whether visible emissions were normal for the process.
  c. The cause of the visible emissions.
  d. Corrective action(s) taken shall be recorded.

vii. For the purpose of calculation excess emissions, a control efficiency of 0% shall be assumed for all periods the thermal oxidizer is receiving emissions during which the combustion chamber temperature of the thermal oxidizer is more than 28 degrees Celsius (50 degrees Fahrenheit) below the average combustion chamber temperature of the thermal oxidizer during the most recent performance test.

b) In accordance with 401 KAR 52:020, Section 26, all records shall be retained at the source for a period of five years.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 59:005, Section 3(2), the permittee of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility.

b) In accordance with 401 KAR 52:020, Section 26, the permittee shall maintain the results of all compliance tests.

c) In accordance with 401 KAR 52:020, Section 26, the permittee shall maintain records of monthly natural gas usage, hours of operation and amount and type of waste gas treated during each twelve (12) consecutive months.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 51:017, Prevention of significant deterioration of air quality, the permittee shall comply with best available control technology with use of low ash/low sulfur natural gas fuel and good flare design.

b) Pursuant to 401 KAR 51:017 and 401 KAR 50:055, Sections 1 and 2, any time the Thermal Oxidizer is not in operation the permittee shall initiate a shutdown of the gasifiers.

c) In accordance with 401 KAR 50:055, a thermocouple shall be used to continuously monitor the temperature of the combustion chamber of the thermal oxidizer to ensure proper combustion chamber operation. The thermocouple shall be calibrated annually.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 11 (11) Unit 11 (Sulfur material handling)

Description:

Liquid sulfur from the Acid Gas Removal System (AGR)
Bulk loading of sulfur.
Construction commenced: expected 2009

Applicable Regulations:

401 KAR 51:017, Prevention of significant deterioration of air quality
401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances

1. **Operating Limitations:**

   None

2. **Emission Limitations:**

   Pursuant to 401 KAR 51:017, the degassing of the molten sulfur and sulfur storage facility for the sulfur recovery unit shall be vented back into the sulfur recovery unit or the associated tail gas treatment unit. For tanker truck or railcar loading of liquid sulfur, the loading rack shall include a vapor recovery system to return the displaced vapors to either the sulfur storage tank or to the sulfur recovery unit.

3. **Testing Requirements:**

   None

4. **Specific Monitoring Requirements:**

   None

5. **Specific Record Keeping Requirements:**

   Pursuant to 401 KAR 52:020, Section 26, the permittee shall retain records of routine and non-routine maintenance of the vapor recovery system.

6. **Specific Reporting Requirements:**

   See Section F for further requirements.

7. **Specific Control Equipment Operating Conditions:**

   Pursuant to 401 KAR 51:017, Prevention of significant deterioration of air quality, the permittee shall comply with best available control technology with the use of degassing and vapor recovery.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 06 (06) Unit 6 Coal Handling Operations (Coal crushing and processing operations)

Description:

Equipment includes: Conveyor transfer-800tph (37), barge unloading-700tph (38), conveyor transfer-800tph (K3), transfer house #1-800tph (THDC33), transfer house #2-800tph (THDC34), coal reclaim-105tph (CRD35)
Control equipment: Baghouses, telescopic chutes, water spray
Operating rate: see above for specific tons/hour
Construction commenced: expected 2009

Applicable Regulations:

401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Y, Standards of performance for coal preparation plants, for emissions units commenced after October 24, 1974, and

401 KAR 51:017, Prevention of significant deterioration of air quality

1. **Operating Limitations:**

   None

2. **Emission Limitations:**

   Pursuant to 401 KAR 60:005, Section 3(1) (ff) incorporating by reference 40 CFR 60 Subpart Y, 40 CFR 60.252, the permittee subject to the provisions of this regulation shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater.

3. **Testing Requirements:**

   Pursuant to 401 KAR 60:005, Section 3(1)(ff) incorporating by reference, 40 CFR 60.254, EPA Reference Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity upon request by the Division.

4. **Specific Monitoring Requirements:**

   In accordance with 401 KAR 52:020, Section 26, the permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, the permittee shall determine the opacity of emissions by Reference Method 9 and initiate an inspection of the control equipment making any necessary repairs.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

5. **Specific Record Keeping Requirements:**

a) Pursuant to 401 KAR 52:020, Section 26, the permittee shall maintain the records of amount of coal received and processed.

b) Pursuant to 401 KAR 52:020, Section 26, the permittee shall maintain the results of all compliance tests. The permittee shall record each week, the date and time of each observation and opacity of visible emissions monitoring. In case of exceedances, the permittee must record the reason (if known) and the measures taken to minimize or eliminate exceedances.

6. **Specific Reporting Requirements:**
See Section F for further requirements.

7. **Specific Control Equipment Operating Conditions:**

a) The enclosure on the conveyors and transfer points, coal bunkers, and for the coal pile reclaim shall be operated to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance of the control equipments shall be maintained.

c) Refer to General Conditions of the Permit, Section F. [401 KAR 50:055 Section 2(5)]

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit 07 (07) Unit 7 Coal Handling Operations

Description:

Dead coal storage pile-90, 000 tons (20a), coal stacker to long term storage pile-2.5 acres (20b)
Control equipment: Compaction, wet suppression
Construction commenced: expected 2009

Applicable Regulations:

401 KAR 63:010, Fugitive emissions is applicable to each affected facility which emits or may emit fugitive emissions and is not elsewhere subject to an opacity standard within the administrative regulations of the Division of Air Quality.

401 KAR 51:017, Prevention of significant deterioration of air quality

1. **Operating Limitations:**

a) Pursuant to 401 KAR 51:017 and 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, as needed, but not be limited to the following:

1. Application and maintenance of asphalt, application of water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts;

2. Operation of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling;

3. The maintenance of paved roadways.

4. The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or other earth moving equipment or erosion by water;

5. Installation and use of compaction or other measures to suppress the dust emissions during handling.

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a paved street or roadway, pursuant to 401 KAR 63:010, Section 4.

d) Pursuant to 401 KAR 51:017, the permittee shall apply compaction and water suppression control methods as BACT.

2. **Emission Limitations:**

None

3. **Testing Requirements:**

None

4. **Specific Monitoring Requirements:**

a) Pursuant to 401 KAR 52:020, Section 26, the permittee shall perform a qualitative visual observation on a weekly basis and maintain a log of the observations and corrective actions.

b) See Section F.

5. **Specific Record Keeping Requirements:**

a) Pursuant to 401 KAR 52:020, Section 26, records of the fossil fuels processed shall be maintained.

b) Pursuant to 401 KAR 52:020, Section 26, annual records estimating the tonnage hauled on plant roadways shall be maintained.

c) Pursuant to 401 KAR 52:020, Section 26, the permittee shall maintain a log of the date, time and results of the monitoring required in Subsection 4 above.

6. **Specific Reporting Requirements:**

See Section F.

7. **Specific Control Equipment Operating Conditions:**

a) Pursuant to 401 KAR 50:055, Section 5 and 401 KAR 51:017, the water spray, compaction and other control measures shall be used to maintain compliance with permitted applicable requirements, in accordance with standard operating practices.

b) Plant roadways shall be paved and controlled with water to comply with 401 KAR 63:010.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to 401 KAR 59:055, Section 3(4), records regarding the maintenance of the control equipment shall be maintained.

d) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 08 (08) - Unit 8 Cooling Tower

Description:

Ten cell cooling tower
Circulating Rate: 375,000 gallons/minute
Control equipment: high efficiency 0.0005% mist eliminators
Construction commenced: Expected Summer 2009

Applicable Regulations:

401 KAR 63:010, Fugitive emissions, and

401 KAR 51:017, Prevention of Significant Deterioration of Air Quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

   b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited

   c) Pursuant to 401 KAR 51:017, the cooling tower circulating water rate shall not exceed 375,000 gals/minute on a daily average.

   d) Pursuant to 401 KAR 51:017 the total dissolved solids (TDS) concentration in the circulated cooling water shall not exceed a TDS concentration of 2,300 parts per million.

2. **Emission Limitations:**

   a) Pursuant to 401 KAR 51:017, the cooling tower shall be equipped with high efficiency drift eliminators that are designed to reduce drift to less than 0.0005 percent. Verification of drift loss shall be by manufacturer's guarantee.

   b) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

   c) Pursuant to 401 KAR 51:017, the PM/PM_{10} BACT emission limit for the cooling tower shall be 2.16 lbs/hr.

3. **Testing Requirements:**

   An initial performance test to verify drift percent achieved by the drift eliminator will be conducted based on the Cooling Technology Institute (CTI) Acceptance Test Code (ATC) # 140. Drift percentage shall be tested prior to permit renewal.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. Specific Monitoring Requirements:

a) Pursuant to 401 KAR 52:020, Section 26, the permittee shall monitor total dissolved solids content of the circulating water on a weekly basis.

b) Pursuant to 401 KAR 52:020, Section 26, the permittee shall monitor the circulating water rate on a daily basis.

5. Specific Recordkeeping Requirements:

a) Pursuant to 401 KAR 52:020, Section 26, the permittee shall maintain records of the manufacturer's design of the Drift Eliminators.

b) Pursuant to 401 KAR 52:020, Section 26, the permittee shall maintain records of the daily amount of water circulated.

c) Pursuant to 401 KAR 52:020, Section 26, results of the TDS monitoring required above shall be recorded weekly.

d) Pursuant to 401 KAR 52:020, Section 26, the permittee shall, using the most recent values for TDS and circulating water rate, calculate and record the emissions from the cooling tower on a weekly basis.

6. Specific Reporting Requirements:

See Section F for further requirements.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5, the drift eliminators shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010 and in accordance with manufacturer's specifications and/or standard operating practices.

b) See Section E for further requirements.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 09 (09) Unit 9 Emergency Fire Pump
Description:
Emergency fire pump, 2.4 MMBtu, industrial engine natural gas-fired
Construction commenced: Proposed Start-Up 2010

Applicable Regulations:

401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982

40 CFR 60, Subpart JJJJ, National Emission Standards for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; Proposed Rule published in the Federal Register on June 12, 2006.

1. **Operating Limitations:**

   a) The maximum operating time for the Emergency Fire Pump shall not exceed 500 hours in any consecutive twelve months (PSD BACT limit on operating hours).

   b) See Section D

2. **Emission Limitations:**

   Pursuant to 401 KAR 51:017 and the proposed revisions to NSPS Subpart JJJJ, owners and operators of stationary SI natural gas and lean burn LPG engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (d) of 40 CFR 60 Subpart JJJJ except that such owners and operators must meet a nitrogen oxides (NOX) emission standard of 3.0 grams per HP-hour (g/HP-hr), a carbon monoxide (CO) emission standard of 4.0 g/HP-hr, and a non-methane hydrocarbons (NMHC) emission standard of 1.0 g/HP-hr, where the date of manufacture of the engine is:
   (i) Prior to July 1, 2007, for non- emergency engines with a maximum engine power greater than or equal to 500 HP;
   (ii)Prior to January 1, 2009, for emergency engines.

3. **Testing Requirements:**

   a) Pursuant to 401 KAR 59:005, Section 2 the permittee shall demonstrate compliance with the applicable emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Pursuant to 40 CFR 60.4244, [per proposed revisions to NSPS Subpart JJJJ published in the Federal Register on June 12, 2006] Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in paragraphs (1) through (6).

(1) performance test must be conducted according to the requirements in 40 CFR 60.8 and under the specific conditions that are specified by Table 2 to this subpart.

(2) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in 40 CFR 60.8(c).

(3) You must conduct three separate test runs for each performance test, as specified in 40 CFR 60.8(f). Each test run must last at least 1 hour.

(4) To determine compliance with the NOX mass per unit output emission limitation, convert the concentration of NOX in the engine exhaust using the following equation:

$$ER = (Cd \times 1\ 912 \times 10-3 \times Q \times T) / (HP - hr) \quad \text{(Eq. 1)}$$

Where:
ER = Emission rate of NOX in g/HP-hr.
Cd = Measured NOX concentration in parts per million (ppm).
1.912 × 10-3 = Conversion constant for ppm NOX to grams per standard cubic meter at 25 degrees Celsius.
Q = Stack gas volumetric flow rate, in standard cubic meter per hour.
T = Time of test run, in hours.
HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

(5) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using the following equation:

$$ER = (Cd \times 1\ 164 \times 10-3 \times Q \times T) / (HP - hr) \quad \text{(Eq. 2)}$$

Where:
ER = Emission rate of CO in g/HP-hr.
Cd = Measured CO concentration in ppm.
1.164 × 10-3 = Conversion constant for ppm CO to grams per standard cubic meter at 25 degrees Celsius.
Q = Stack gas volumetric flow rate, in standard cubic meters per hour.
T = Time of test run, in hours.
HP-hr = Brake work of the engine, in HP-hr.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

(6) To determine compliance with the NMHC mass per unit output emission limitation, convert the concentration of NMHC in the engine exhaust using the following equation:

ER = (Cd ×1 832 ×10-3 × Q ×.T) / (HP - hr) (Eq. 3)

Where:
ER = Emission rate of NMHC in g/HP-hr.
Cd = NMHC concentration measured as propane in ppm.
1.832 × 10-3 = Conversion constant for ppm NMHC measured as propane, to grams per standard cubic meter at 25 degrees Celsius.
Q = Stack gas volumetric flow rate, in standard cubic meters per hour.
T = Time of test run, in hours.
HP-hr = Brake work of the engine, in HP-hr.

4. Specific Monitoring Requirements:

a) In accordance with 401 KAR 52:020, Section 26, the permittee shall monitor the monthly fuel usage, the average monthly fuel heat content, and the monthly hours of operation.

b) Pursuant to 40 CFR 60.4237 the permittee of an emergency stationary SI internal combustion engine must install a non-resettable hour meter prior to startup of the engine.

5. Specific Recordkeeping Requirements:

a) In accordance with 401 KAR 52:020, Section 26, the permittee shall maintain records of monthly fuel used, monthly average fuel heat content, and monthly hours of operation of the emergency fire pump.

b) Pursuant to 40 CFR 60.4245(a) owners and operators of all stationary SI ICE must keep records of the information in paragraphs (1) through (4).

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.
(2) Maintenance conducted on the engine.
(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 90 and 1048.
(4) If the stationary SI internal combustion engine is not a certified engine, documentation that the engine meets the emission standards.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c) Pursuant to 40 CFR 60.4245(b) the permittee of stationary SI emergency ICE must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The permittee must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

6. Specific Reporting Requirements:

a) Pursuant to 40 CFR 60.4245(c) owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in 40 CFR 60.4231 must submit an initial notification as required in 40 CFR 60.7(a)(1). The notification must include the information in paragraphs (1) through (5).

(1) Name and address of the owner or operator;
(2) The address of the affected source;
(3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;
(4) Emission control equipment; and
(5) Fuel used.

b) Pursuant to 40 CFR 60.4245(d) owners and operators of stationary SI ICE that have not been certified by an engine manufacturer to meet the emission standards in 40 CFR 60.4231 must submit a copy of each performance test as conducted in 40 CFR 60.4244 within 30 days after the test has been completed.

7. Specific Control Equipment Operating Conditions:

None

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emissions Unit: 10 (10) Plant Roadways [Emissions Units: HRP]

Description:
Paved and unpaved roadways
Construction commenced: Proposed Start-Up 2008

Applicable Regulations:

401 KAR 63:010, Fugitive emissions is applicable to each affected facility which emits or may emit fugitive emissions and is not elsewhere subject to an opacity standard within the administrative regulations of the Division of Air Quality.

401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982

1. **Operating Limitations:**

   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following:

      1. application and maintenance of asphalt, application of water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts;

      2. the maintenance of paved roadways in a clean condition;

      3. the prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or other earth moving equipment or erosion by water.

   b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

   c) No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a paved street or roadway, pursuant to 401 KAR 63:010, Section 4.

2. **Emission Limitations:**
   None

3. **Testing Requirements:**
   None

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. Specific Monitoring Requirements:

See Section F.

5. Specific Record Keeping Requirements:

Records of the tonnage of materials hauled shall be maintained for emissions inventory purposes.

6. Specific Reporting Requirements:

See Section F.

7. Specific Control Equipment Operating Conditions:

a) All control measures shall be in place, properly maintained, and in operation to maintain compliance with the permitted emission limitations, and in accordance with standard operating procedures. (401 KAR 51:017 and 401 KAR 50:055)

b) See Section E for further requirements.

SECTION C - INSIGNIFICANT ACTIVITIES

The following listed activities have been determined to be insignificant activities for this source pursuant to 401 KAR 52:020, Section 6. While these activities are designated as insignificant the permittee must comply with the applicable regulation and some minimal level of monitoring may be necessary. Process and emission control equipment at each insignificant activity subject to a general applicable regulation shall be inspected monthly and qualitative visible emission evaluation made. The results of the inspections and observations shall be recorded in a log, noting color, duration, density (heavy or light), cause and any conservative actions taken for any abnormal visible emissions.

Description	Generally Applicable Regulation
Cold Solvent Parts Cleaners	401 KAR 59:0158
10,000 Gallon Diesel Fuel Storage Tank	None
2-20,000 Gallon Miscellaneous Tanks	None
Maintenance Activities	None
Dead Coal Storage Pile	401 KAR 63:010
Slag Landfill	401 KAR 63:010
Misc. Storage Tanks	401 KAR 68:150
Ammonia Storage Tanks	401 KAR 68:150

SECTION D - SOURCE EMISSION LIMITATIONS AND TESTING REQUIREMENTS

1. As required by Section 1b of the Cabinet Provisions and Procedures for Issuing Title V Permits incorporated by reference in 401 KAR 52:020, Section 26; compliance with annual emissions and processing limitations contained in this permit, shall be based on emissions and processing rates for any twelve (12) consecutive months.

2. Particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide (CO), mercury (Hg) and sulfuric acid mist (H_2SO_4) emissions, measured by applicable reference methods, or an equivalent or alternative method specified in 40 C.F.R. Chapter I, or by a test method specified in the state implementation plan shall not exceed the respective limitations specified herein.

3. Emission Units 01 and 02 shall be performance tested initially for compliance with the emission standards for PM/PM_{10} (filterable and total); sulfur dioxide (SO_2); nitrogen oxides (NO_x); carbon monoxide (CO), mercury; and H_2SO_4 by applicable reference methods, or by equivalent or alternative test methods specified in this permit or approved by the cabinet (and U.S.EPA, if required).

4. Emission Units 01 and 02 shall be performance tested biannually (once every 24 months) for compliance with the emission standards for PM/PM_{10} (filterable and total); mercury and H_2SO_4 by applicable reference methods, or by equivalent or alternative test methods specified in this permit or approved by the cabinet (and U.S.EPA, if required).

5. Emission Unit 01 or 02 shall be performance tested using Method 26A or by equivalent or alternative test methods approved by the cabinet to determine emissions of HCl. Results shall be used to confirm that emissions of Hazardous Air Pollutants are below 10 tons per a single HAP and 25 tons per combined HAPs in a year. This testing will confirm that the requirements in 40 CFR 63 do not apply.

6. Emission Units 03 (Auxiliary Boiler) shall be performance tested initially for compliance with the emission standards for PM/PM_{10} (filterable); nitrogen oxides (NO_x); and carbon monoxide (CO), by applicable reference methods, or by equivalent or alternative test methods specified in this permit or approved by the cabinet (and U.S.EPA, if required).

7. The maximum operating time for Emission Units 03 (Auxiliary Boiler) and emergency fire pump shall not exceed 500 hours each in any consecutive twelve months (401 KAR 51:017).

8. After the initial compliance test for Units 01 and 02, and CEMS certification as stated in 401 KAR 50:055, continuing compliance with the emission standards shall be determined by continuous monitoring systems for NOx, CO, Hg, and SO_2.

SECTION E - SOURCE CONTROL EQUIPMENT REQUIREMENTS

Pursuant to 401 KAR 50:055, Section 2(5), at all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS

Pursuant to Section 1b (IV)1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26, when continuing compliance is demonstrated by periodic testing or instrumental monitoring, the permittee shall compile records of required monitoring information that include:

   a. Date, place as defined in this permit, and time of sampling or measurements;
   b. Analyses performance dates;
   c. Company or entity that performed analyses;
   d. Analytical techniques or methods used;
   e. Analyses results; and
   f. Operating conditions during time of sampling or measurement.

2. Records of all required monitoring data and support information, including calibrations, maintenance records, and original strip chart recordings, and copies of all reports required by the Division of Air Quality, shall be retained by the permittee for a period of five years and shall be made available for inspection upon request by any duly authorized representative of the Division of Air Quality [Sections 1b(IV) 2 and 1a(8) of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

3. In accordance with the requirements of 401 KAR 52:020 Section 3(1)h the permittee shall allow authorized representatives of the Cabinet to perform the following during reasonable times:
   a. Enter upon the premises to inspect any facility, equipment (including air pollution control equipment), practice, or operation;
   b. To access and copy any records required by the permit:
   c. Sample or monitor, at reasonable times, substances or parameters to assure compliance with the permit or any applicable requirements.

   Reasonable times are defined as during all hours of operation, during normal office hours; or during an emergency.

4. No person shall obstruct, hamper, or interfere with any Cabinet employee or authorized representative while in the process of carrying out official duties. Refusal of entry or access may constitute grounds for permit revocation and assessment of civil penalties.

5. Summary reports of any monitoring required by this permit shall be submitted to the Regional Office listed on the front of this permit at least every six (6) months during the life of this permit, unless otherwise stated in this permit. For emission units that were still under construction or which had not commenced operation at the end of the 6-month period covered by the report and are subject to monitoring requirements in this permit, the report shall indicate that no monitoring was performed during the previous six months because the emission unit was not in operation [Section 1b (V)1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

6. The semi-annual reports are due by January 30th and July 30th of each year. All reports shall be certified by a responsible official pursuant to 401 KAR 52:020 Section 23. If continuous emission and opacity monitors are required by regulation or this permit, data shall be reported in accordance with the requirements of 401 KAR 59:005, General Provisions, Section 3(3). All deviations from permit requirements shall be clearly identified in the reports.

7. In accordance with the provisions of 401 KAR 50:055, Section 1 the permittee shall notify the Regional Office listed on the front of this permit concerning startups, shutdowns, or malfunctions as follows:
    a. When emissions during any planned shutdowns and ensuing startups will exceed the standards, notification shall be made no later than three (3) days before the planned shutdown, or immediately following the decision to shut down, if the shutdown is due to events which could not have been foreseen three (3) days before the shutdown.
    b. When emissions due to malfunctions, unplanned shutdowns and ensuing startups are or may be in excess of the standards, notification shall be made as promptly as possible by telephone (or other electronic media) and shall be submitted in writing upon request.

8. The permittee shall report emission related exceedances from permit requirements including those attributed to upset conditions (other than emission exceedances covered by Section F.7. above) to the Regional Office listed on the front of this permit within 30 days. Deviations from permit requirements, including those previously reported under F.7 above, shall be included in the semiannual report required by F.6 [Section 1b (V) 3, 4. of the Cabinet Provisions and Procedures for Issuing Title V Permits incorporated by reference in 401 KAR 52:020, Section 26].

9. Pursuant to 401 KAR 52:020, Permits, Section 21, the permittee shall annually certify compliance with the terms and conditions contained in this permit, by completing and returning a Compliance Certification Form (DEP 7007CC) (or an alternative approved by the regional office) to the Regional Office listed on the front of this permit and the U.S. EPA in accordance with the following requirements:
    a. Identification of the term or condition;
    b. Compliance status of each term or condition of the permit;
    c. Whether compliance was continuous or intermittent;
    d. The method used for determining the compliance status for the source, currently and over the reporting period.
    e. For an emissions unit that was still under construction or which has not commenced operation at the end of the 12-month period covered by the annual compliance certification, the permittee shall indicate that the unit is under construction and that compliance with any applicable requirements will be demonstrated within the timeframes specified in the permit.

SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

f. The certification shall be postmarked by January 30th of each year. Annual compliance certifications shall be mailed to the following addresses:

Division of Air Quality
Owensboro Regional Office
3032 Alvey Park Drive
Suite 700
Owensboro, KY 42303

U.S. EPA Region 4
Air Enforcement Branch
Atlanta Federal Center
61 Forsyth St.
Atlanta, GA 30303-8960

Division of Air Quality
Central Files
803 Schenkel Lane
Frankfort, KY 40601

10. In accordance with 401 KAR 52:020, Section 22, the permittee shall provide the Division with all information necessary to determine its subject emissions within thirty (30) days of the date the KYEIS emission survey is mailed to the permittee.

11. Results of performance test(s) required by the permit shall be submitted to the Division by the source or its representative within forty-five days or sooner if required by an applicable standard, after the completion of the fieldwork.

SECTION G - GENERAL PROVISIONS

(a) General Compliance Requirements

1. The permittee shall comply with all conditions of this permit. Noncompliance shall be a violation of 401 KAR 52:020 and of the Clean Air Act and is grounds for enforcement action including but not limited to termination, revocation and reissuance, revision or denial of a permit [Section 1a, 3 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020 Section 26].

2. The filing of a request by the permittee for any permit revision, revocation, reissuance, or termination, or of a notification of a planned change or anticipated noncompliance, shall not stay any permit condition [Section 1a, 6 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

3. This permit may be revised, revoked, reopened and reissued, or terminated for cause in accordance with 401 KAR 52:020, Section 19. The permit will be reopened for cause and revised accordingly under the following circumstances:
   a. If additional applicable requirements become applicable to the source and the remaining permit term is three (3) years or longer. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if compliance with the applicable requirement is not required until after the date on which the permit is due to expire, unless this permit or any of its terms and conditions have been extended pursuant to 401 KAR 52:020, Section 12;
   b. The Cabinet or the U. S. EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements;
   c. The Cabinet or the U. S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit;
   d. If any additional applicable requirements of the Acid Rain Program become applicable to the source.

   Proceedings to reopen and reissue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable. Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the Division, at least thirty (30) days in advance of the date the permit is to be reopened, except that the Division may provide a shorter time period in the case of an emergency.

4. The permittee shall furnish information upon request of the Cabinet to determine if cause exists for modifying, revoking and reissuing, or terminating the permit; or to determine compliance with the conditions of this permit [Section 1a, 7,8 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

5. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such facts or corrected information to the permitting authority [401 KAR 52:020, Section 7(1)].

SECTION G - GENERAL PROVISIONS (CONTINUED)

6. Any condition or portion of this permit which becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this permit [Section 1a, 14 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

7. The permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance [Section 1a, 4 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

8. Except for requirements identified in this permit as state-origin requirements, all terms and conditions shall be enforceable by the United States Environmental Protection Agency and citizens.[Section 1a, 15 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

9. This permit shall be subject to suspension if the permittee fails to pay all emissions fees within 90 days after the date of notice as specified in 401 KAR 50:038, Section 3(6) [Section 1a, 10 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

10. Nothing in this permit shall alter or affect the liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance [401 KAR 52:020, Section 11(3)(b)].

11. This permit does not convey property rights or exclusive privileges [Section 1a, 9 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

12. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Kentucky Cabinet for Environmental and Public Protection or any other federal, state, or local agency.

13. Nothing in this permit shall alter or affect the authority of U.S. EPA to obtain information pursuant to Federal Statute 42 USC 7414, Inspections, monitoring, and entry [401 KAR 52:020, Section 11(3)(d)].

14. Nothing in this permit shall alter or affect the authority of U.S. EPA to impose emergency orders pursuant to Federal Statute 42 USC 7603, Emergency orders [401 KAR 52:020, Section 11(3)(a)].

15. This permit consolidates the authority of any previously issued PSD, NSR, or Synthetic Minor source preconstruction permit terms and conditions for various emission units and incorporates all requirements of those existing permits into one single permit for this source.

SECTION G - GENERAL PROVISIONS (CONTINUED)

16. Pursuant to 401 KAR 52:020, Section 11, a permit shield shall not protect the permittee from enforcement actions for violating an applicable requirement prior to or at the time of issuance. Compliance with the conditions of a permit shall be considered compliance with:
    a. Applicable requirements that are included and specifically identified in the permit and
    b. Non-applicable requirements expressly identified in this permit.

17. Pursuant to 401 KAR 50:045, Section 2, a source required to conduct a performance test shall submit a completed Compliance Test Protocol form, DEP form 6028, or a test protocol a source has developed for submission to other regulatory agencies, in a format approved by the cabinet, to the Division's Frankfort Central Office a minimum of sixty (60) days prior to the scheduled test date. Pursuant to 401 KAR 50:045, Section 7, the Division shall be notified of the actual test date at least Thirty (30) days prior to the test.

(b) Permit Expiration and Reapplication Requirements

1. This permit shall remain in effect for a fixed term of five (5) years following the original date of issue. Permit expiration shall terminate the source's right to operate unless a timely and complete renewal application has been submitted to the Division at least six months prior to the expiration date of the permit. Upon a timely and complete submittal, the authorization to operate within the terms and conditions of this permit, including any permit shield, shall remain in effect beyond the expiration date, until the renewal permit is issued or denied by the Division [401 KAR 52:020, Section 12].

2. The authority to operate granted shall cease to apply if the source fails to submit additional information requested by the Division after the completeness determination has been made on any application, by whatever deadline the Division sets [401 KAR 52:020 Section 8(2)].

(c) Permit Revisions

1. A minor permit revision procedure may be used for permit revisions involving the use of economic incentive, marketable permit, emission trading, and other similar approaches, to the extent that these minor permit revision procedures are explicitly provided for in the SIP or in applicable requirements and meet the relevant requirements of 401 KAR 52:020, Section 14(2).

2. This permit is not transferable by the permittee. Future owners and operators shall obtain a new permit from the Division of Air Quality. The new permit may be processed as an administrative amendment if no other change in this permit is necessary, and provided that a written agreement containing a specific date for transfer of permit responsibility coverage and liability between the current and new permittee has been submitted to the permitting authority within ten (10) days following the transfer.

SECTION G - GENERAL PROVISIONS (CONTINUED)

(d) Construction, Start-Up, and Initial Compliance Demonstration Requirements

Pursuant to a duly submitted application the Kentucky Division of Air Quality hereby authorizes the construction of the equipment described herein, Emissions Units 01 through 11 in accordance with the terms and conditions of this permit.

1. Construction of any process and/or air pollution control equipment authorized by this permit shall be conducted and completed only in compliance with the conditions of this permit.

2. Within thirty (30) days following commencement of construction and within fifteen (15) days following start-up and attainment of the maximum production rate specified in the permit application, or within fifteen (15) days following the issuance date of this permit, whichever is later, the permittee shall furnish to the Regional Office listed on the front of this permit in writing, with a copy to the Division's Frankfort Central Office, notification of the following:
   a. The date when construction commenced.
   b. The date of start-up of the affected facilities listed in this permit.
   c. The date when the maximum production rate specified in the permit application was achieved.

3. Pursuant to 401 KAR 52:020, Section 3(2), unless construction is commenced within eighteen (18) months after the permit is issued, or begins but is discontinued for a period of eighteen (18) months or is not completed within a reasonable timeframe then the construction and operating authority granted by this permit for those affected facilities for which construction was not completed shall immediately become invalid. Upon written request, the Cabinet may extend these time periods if the source shows good cause.

4. For those affected facilities for which construction is authorized by this permit, a source shall be allowed to construct with the proposed permit. Operational or final permit approval is not granted by this permit until compliance with the applicable standards specified herein has been demonstrated pursuant to 401 KAR 50:055. If compliance is not demonstrated within the prescribed timeframe provided in 401 KAR 50:055, the source shall operate thereafter only for the purpose of demonstrating compliance, unless otherwise authorized by Section I of this permit or order of the Cabinet.

5. This permit shall allow time for the initial start-up, operation, and compliance demonstration of the affected facilities listed herein. However, within sixty (60) days after achieving the maximum production rate at which the affected facilities will be operated but not later than 180 days after initial start-up of such facilities, the permittee shall conduct a performance demonstration or test on the affected facilities in accordance with 401 KAR 50:055, General compliance requirements. These performance tests must also be conducted in accordance with General Provisions G(d)7 of this permit and the permittee must furnish to the Division of Air Quality's Frankfort Central Office a written report of the results of such performance test

SECTION G - GENERAL PROVISIONS (CONTINUED)

6. Terms and conditions in this permit established pursuant to the construction authority of 401 KAR 51:017 or 401 KAR 51:052 shall not expire.

7. Pursuant to 401 KAR 50:045 Section 5 in order to demonstrate that a source is capable of complying with a standard at all times, a performance test shall be conducted under normal conditions that are representative of the source's operations and create the highest rate of emissions. If [When] the maximum production rate represents a source's highest emissions rate and a performance test is conducted at less than the maximum production rate, a source shall be limited to a production rate of no greater than 110 percent of the average production rate during the performance tests. If and when the facility is capable of operation at the rate specified in the application, the source may retest to demonstrate compliance at the new production rate. The Division of Air Quality may waive these requirement on a case-by-case basis if the source demonstrates to the Division's satisfaction that the source is in compliance with all applicable requirements.

(e) Acid Rain Program Requirements

1. If an applicable requirement of Federal Statute 42 USC 7401 through 7671q (the Clean Air Act) is more stringent than an applicable requirement promulgated pursuant to Federal Statute 42 USC 7651 through 7651o (Title IV of the Act), both provisions shall apply, and both shall be state and federally enforceable.

2. The source shall comply with all requirements and conditions of the Title IV, Acid Rain Permits issued for this source. The source shall also comply with all requirements of any revised or future acid rain permit(s) issued to this source.

SECTION G - GENERAL PROVISIONS (CONTINUED)

(f) Emergency Provisions

1. Pursuant to 401 KAR 52:020 Section 24(1), an emergency shall constitute an affirmative defense to an action brought for the noncompliance with the technology-based emission limitations if the permittee demonstrates through properly signed contemporaneous operating logs or relevant evidence that:
   a. An emergency occurred and the permittee can identify the cause of the emergency;
   b. The permitted facility was at the time being properly operated;
   c. During an emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and
   d. Pursuant to 401 KAR 52:020, 401 KAR 50:055, and KRS 224.01-400, the permittee notified the Division as promptly as possible and submitted written notice of the emergency to the Division when emission limitations were exceeded due to an emergency. The notice shall include a description of the emergency, steps taken to mitigate emissions, and corrective actions taken.
   e. This requirement does not relieve the source of other local, state or federal notification requirements.

2. Emergency conditions listed in General Condition (f)1 above are in addition to any emergency or upset provision(s) contained in an applicable requirement [401 KAR 52:020, Section 24(3)].

3. In an enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof [401 KAR 52:020, Section 24(2)].

(g) Risk Management Provisions

1. The permittee shall comply with all applicable requirements of 401 KAR Chapter 68, Chemical Accident Prevention, which incorporates by reference 40 CFR Part 68, Risk Management Plan provisions. If required, the permittee shall comply with the Risk Management Program and submit a Risk Management Plan to:

   RMP Reporting Center
   P.O. Box 1515
   Lanham-Seabrook, MD 20703-1515.

2. If requested, submit additional relevant information to the Division or the U.S. EPA.

SECTION G - GENERAL PROVISIONS (CONTINUED)

(h) Ozone depleting substances

1. The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:
   a. Persons opening appliances for maintenance, service, repair, or disposal shall comply with the required practices contained in 40 CFR 82.156.
   b. Equipment used during the maintenance, service, repair, or disposal of appliances shall comply with the standards for recycling and recovery equipment contained in 40 CFR 82.158.
   c. Persons performing maintenance, service, repair, or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.
   d. Persons disposing of small appliances, MVACs, and MVAC-like appliances (as defined at 40 CFR 82.152) shall comply with the recordkeeping requirements pursuant to 40 CFR 82.166
   e. Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.
   f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

2. If the permittee performs service on motor (fleet) vehicle air conditioners containing ozone-depleting substances, the source shall comply with all applicable requirements as specified in 40 CFR 82, Subpart B, *Servicing of Motor Vehicle Air Conditioners*.

SECTION H - ALTERNATE OPERATING SCENARIOS

Not Applicable

SECTION I - COMPLIANCE SCHEDULE

Not Applicable

SECTION J – ACID RAIN

TITLE IV PHASE II ACID RAIN

ACID RAIN PERMIT CONTENTS

1) Statement of Basis

2) SO_2 allowances allocated under this permit and NOx requirements for each affected unit.

3) Comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.

4) The permit application submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the Phase II Application and the Phase II NOx Compliance Plan.

5) Summary of Actions

- **Statement of Basis:**

Statutory and Regulatory Authorities: In accordance with KRS 224.10-100 and Titles IV and V of the Clean Air Act, the Kentucky Environmental and Public Protection Cabinet, Division of Air Quality issues this permit pursuant to 401 KAR 52:020, Permits, 401 KAR 52:060, Acid Rain Permit, and Federal Regulation 40 CFR 76.

PERMIT (Conditions)

Plant Name: Cash Creek Generation Station	
Affected Unit: 01 – HRSG-1, 02 – HRSG-2	

1. **SO_2 Allowance Allocations and NO_x Requirements for the affected unit:**

SO_2 Allowances	**Year**				
	2006	2007	2008	2009	2010
Tables 2, 3 or 4 of 40 CFR Part 73	0*	0*	0*	0*	0*

NO_x Requirements	
NO_x Limits	N/A**

* For newly constructed units, there are no SO2 allowances per USEPA Acid Rain Program

** These units currently do not have applicable NO_x limits set by 40 CFR, part 76. Limits will be set by 40 CFR 76 upon construction.

PERMIT (Conditions)

2. Comments, Notes, and Justifications:

The two (2) Integrated Combined Cycle Combustion Turbines with heat recovery steam generators, units 01 and 02 will be constructed after the SO_2 allocation date; therefore these units will have no SO_2 allowances allocated by U.S. EPA and must obtain allowances.

The two (2) Combined Cycle Combustion Turbines, units 01 and 02 do not have applicable NO_x limits set by 40 CFR part 76.

3. Permit Application:

The Phase II Permit Application is a part of this permit and the source must comply with the standard requirements and special provisions set forth in the Phase II Application.

4. Summary of Actions:

Draft Title V with Acid Rain Permit was advertised for public comments.

Present Action:

Proposed Title V permit being issued with the Title IV permit.

SECTION K – NOx BUDGET

Statement of Basis

Statutory and Regulatory Authorities: In accordance with KRS 224.10-100, the Kentucky Environmental and Public Protection Cabinet issues this permit pursuant to 401 KAR 52:020 Title V permits, 401 KAR 51:210, CAIR NOx Annual Trading Program and 401 KAR 51:220, CAIR NOx Ozone Trading Program.

NOx Budget Permit Application, Form DEP 7007EE

The CAIR Permit application for these electrical generating units was submitted to the Division and received on May 4, 2006. Requirements contained in that application are hereby incorporated into and made part of this CAIR Permit. Pursuant to 401 KAR 52:020, Section 3, the source shall operate in compliance with those requirements.

Comments, notes, justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.

Affected units are two (2) combined cycle combustion turbine rated 2114 MMBtu/hour and one 278.8 mmBtu/hr auxiliary boiler. Each combustion turbine unit has a capacity to generate 25 megawatts or more of electricity, which is offered for sale. The combustion turbine units use syngas from coal and natural gas as a fuel source, and are used as electric generating units. The auxiliary boiler has a capacity greater than the 250 MMBtu/hour, thus 401 KAR 51:220 is applicable, however since it is not considered an Electric Generating Unit, 401 KAR 52:210 is not applicable..

Summary of Actions

The CAIR Permit is being issued as part of the initial Title V permit for this source. Public, affected state, and U.S. EPA review will follow procedures specified in 401 KAR 52:100.

June 29, 2007

VIA U.S. MAIL, EMAIL, AND HAND DELIVERY

James Morse, Permit Review
Kentucky Environmental and Public Protection Cabinet
Division for Air Quality
803 Schenkel Lane
Frankfort, KY 40601

Re: Public Comments on Draft Construction and Operating Permit V-07-017 for the Cash Creek Generating Station

Dear Mr. Morse:

We are writing to submit comments on the Draft PSD/Title V Permit for the proposed Cash Creek Generating Station, Permit No. V-07-017 (dated complete March 29, 2007), on behalf of Sierra Club, Valley Watch, Inc., and the Environmental Law and Policy Center. These comments will be presented in written form in person at the public hearing to be held today, June 29, in Kentucky by John Blair and/or Wallace McMullen (as Sierra Club representative), and therefore are timely-submitted pursuant to communications with John Lyons and yourself.

For the reasons discussed below, the Kentucky Division of Air Quality ("KDAQ") must either deny the permit or make substantial revisions to the current draft. If the agency revises the draft permit, the revised draft must then be re-noticed and the public must have a full and fair opportunity to comment and request a hearing on the revised draft.

I. IF KDAQ PROCEEDS TO PROCESS THE PROPOSED DRAFT PERMIT, SIGNIFICANT REVISIONS ARE REQUIRED.

a. KDAQ Must Conduct a BACT Analysis for Carbon Dioxide and Set an Emissions Limitation for Carbon Dioxide in the Proposed Permit.

Neither ERORA nor KDAQ addressed the carbon dioxide (CO2) or other greenhouse gases to be emitted from the plant. Yet, the Cash Creek facility will be a significant emitter of greenhouse gas pollutants. Those emissions will contribute significantly to global warming and its adverse impacts on the health, welfare, economy and environment of the State of Kentucky, as well as the planet as a whole. For these reasons, KDAQ should, and indeed must under the Clean Air Act and Kentucky law, conduct a full BACT analysis for CO2.

The federal Clean Air Act and Kentucky Air Quality Regulations prohibit the construction of a new major stationary source of air pollutants at the Cash Creek site except in accordance with a prevention of significant deterioration construction permit issued by KDAQ. Clean Air Act § 165(a), 42 U.S.C. § 7475(a); 401 KAR 51:017. KDAQ must conduct a BACT analysis and include in the construction permit BACT emission limitations "for each pollutant

EXHIBIT B

subject to regulation under [the Clean Air Act]" for which emissions exceed specified significance levels. Clean Air Act, §§ 165(a), 169, 42 U.S.C. §§ 7475(a), 7479; 401 KAR 51:017. In 401 KAR 51:017, KDAQ adopted, largely verbatim, the Environmental Protection Agency's ("EPA") Prevention of Significant Deterioration regulations set forth at 40 C.F.R. § 52.21. The EPA regulations provide that "[a] new major stationary source shall apply best available control technology <u>for each regulated NSR pollutant</u> that it would have the potential to emit in significant amounts." 40 C.F.R. § 52.21(j)(1)(emphasis added); see also 401 KAR 51:017 Section 8. They also define "regulated NSR pollutant" as including "any pollutant . . . subject to regulation under the Act." Specifically, the regulation provides:

> Regulated NSR pollutant, for purposes of this section, means the following:
> (i) Any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (e.g., volatile organic compounds are precursors for ozone);
> (ii) Any pollutant that is subject to any standard promulgated under Section 111 of the Act;
> (iii) Any Class I or Class II substance subject to a standard promulgated under or established by title VI of the Act; or
> (iv) Any pollutant that otherwise is subject to regulation under the Act; except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not been delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

40 C.F.R. § 52.21(b)(50)(emphasis added); see also 401 KAR 51:001 Section 1(211). The statutory definition of BACT also makes clear that BACT requirements apply to all air pollutants subject to regulation under the Clean Air Act. The definition states:

> Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

42 U.S.C. 7479(3); see also 40 C.F.R. § 52.21(b)(12), 401 KAR 51:001 Section 1(25). The BACT analysis review that KDAQ must conduct for each pollutant subject to regulation under the Clean Air Act must include a case specific review of relevant energy, environmental and economic considerations that is informed by detailed information submitted by the applicant. See 42 U.S.C. § 7479(3); 40 C.F.R. 52.21(b)(12), (n). Based on its BACT review, KDAQ must set emission limitations in its permit. See 42 U.S.C. § 7479(3) (BACT means "an emission limitation"); 40 C.F.R. 52.21(b)(12)(same); 401 KAR 51:001 Section 1(25).

It is undisputed that the Cash Creek project is subject to BACT requirements for a number of air pollutants for which emissions will exceed specified significance levels. See Cash Creek Permit Application at 4.1 (Cash Creek will emit PM/PM_{10}, SO_2, NOx, CO and H_2SO_4 in significant amounts for PSD/BACT purposes); see also Statement of Basis, Title V Draft Permit, No. V-07-017 (Apr. 30, 2007) at p.14. The proposed new facility clearly will result in carbon dioxide emissions in excess of any applicable BACT significance threshold.[1] See, e.g., Massachusetts Institute of Technology (2007), "The Future of Coal: options for a carbon-constrained world," ("M.I.T. Study") at p. 30, Table 3.5 (GE radiant cooled gasifier emits CO_2 at a rate of 415,983 kg/hr), Attachment 1.[2]

The proposed permit is subject to BACT requirements for carbon dioxide because carbon dioxide is an "air pollutant" subject to regulation under the Clean Air Act. Section 302(g) of the Clean Air Act defines "air pollutant" expansively to include "any physical, chemical, biological, radioactive . . . substance or matter which is emitted into or otherwise enters into the ambient air." 42 U.S.C. § 7602(g)(emphasis added). In its April 2, 2007 opinion in Massachusetts v. EPA, the Supreme Court held that carbon dioxide and other greenhouse gases are air pollutants as defined in § 302(g), 42 U.S.C. § 7602(g). 127 S. Ct. at 1459-60. The Court based its holding on the "unambiguous" language of the definition. Id. at 1460. The Court further held that because carbon dioxide is within the Clean Air Act's definition of "air pollutant," EPA has the authority to regulate carbon dioxide under the Act. Id. at 1462. The Massachusetts v. EPA decision dispensed with any uncertainty whether carbon dioxide is an "air pollutant" under the Clean Air Act.[3]

Carbon Dioxide is "subject to regulation" under a number of the Clean Air Act's substantive provisions. These provisions include Section 202, which requires standards applicable to emissions of "any air pollutant" from motor vehicles, and Section 111[4], which requires standards of performance for emissions of "air pollutants" from new stationary sources. 42 U.S.C. §§ 7411, 7521. While EPA and the States have not yet established limits under those Clean Air Act provisions, they have the clear statutory authority to do so. Therefore, carbon dioxide is undeniably "subject to regulation" under the Act. The plain meaning of Section 165(a)(4) of the Clean Air Act's mandate that BACT applies to "each pollutant subject to regulation under [the Clean Air Act]" extends not only to air pollutants for which the Act itself or EPA or the States by regulation have imposed requirements, but also to air pollutants for which EPA and the States possess but have not exercised authority to impose such requirements. Regulation under Sections 202 and 111 is required where air pollution "may reasonably be

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[1] Section 52.21(b)(23)(i), 40 C.F.R., does not set forth a significance level for carbon dioxide. Therefore, pursuant to 40 C.F.R. § 52.21(b)(23)(ii), any emissions of carbon dioxide are significant.

[2] The Attachment consists of Chapter 3, "Coal-based Electricity Generation." The full text report is available at web.mit.edu/coal/The_Future_of_Coal.pdf

[3] EPA's then general counsel, Jonathan Z. Cannon, opined in 1998 that carbon dioxide is within the Clean Air Act's definition of "air pollutant" and that EPA has the authority to regulate carbon dioxide. More recently, however, EPA has advanced a contrary interpretation that is contrary to the plain language of Section 302(g) and the Massachusetts v. EPA opinion.

[4] A challenge to EPA's failure to establish emission limits for carbon dioxide emissions from power plants under Section 111 of the Clean Air Act is pending before the United States Court of Appeals for the District of Columbia Circuit. State of New York, et al. v. EPA, No. 06-1322. EPA refused to establish such emission limits solely on the ground that EPA lacked the authority to regulate carbon dioxide under the Clean Air Act. Based on Massachusetts v. EPA, petitioners, on May 2, 2007, asked the Court of Appeals to vacate EPA's determination that it lacks authority to regulate carbon dioxide emissions under Section 111, and to remand the matter to EPA for further proceedings consistent with the Massachusetts v. EPA decision.

anticipated to endanger public health or welfare." 42 U.S.C. § 7411(b)(1)(A); 42 U.S.C. § 7521(a)(1). The Supreme Court's holding in Massachusetts v. EPA dispensed with any uncertainty whether EPA and the States have the authority to take action to control carbon dioxide emissions under Sections 202 and 111.

The Massachusetts v. EPA case specifically involved a challenge to EPA's failure to prescribe regulations on carbon dioxide emissions from motor vehicles under Section 202 of the Clean Air Act. The Court held that EPA has the authority to issue such regulations, and rejected the excuses advanced by EPA for failing to do so. 127 S. Ct. at 1459-63. Following the Court's decision, the President, in a May 14, 2007 Executive Order, acknowledged EPA's authority to regulate emissions of greenhouse gases, including carbon dioxide from motor vehicles, nonroad vehicles and nonroad engines under the Clean Air Act. The Executive Order directs EPA to coordinate with other federal agencies in undertaking such regulatory action.

Moreover, in addition to being subject to regulation under sections 111 and 202 of the Act, carbon dioxide is currently regulated under Section 821 of the Clean Air Act Amendments of 1990. That section required EPA to promulgate, within 18 months after enactment of the Amendments, regulations to require certain sources, including coal-fired electric generating stations, to monitor carbon dioxide emissions and report monitoring data to EPA. 42 U.S.C. § 7651k note. In 1993 EPA promulgated such regulations, which are set forth at 40 C.F.R. Part 75. The regulations generally require monitoring of carbon dioxide emissions through installation, certification, operation and maintenance of a continuous emission monitoring system or an alternative method (40 C.F.R. §§ 75.1(b), 75.10(a)(3)); preparation and maintenance of a monitoring plan (40 C.F.R. § 75.33); maintenance of certain records (40 C.F.R. § 75.57); and reporting of certain information to EPA, including electronic quarterly reports of carbon dioxide emissions data (40 C.F.R. §§ 75.60 – 64). Section 75.5, 40 C.F.R., prohibits operation of an affected source in the absence of compliance with the substantive requirements of Part 75, and provides that a violation of any requirement of Part 75 is a violation of the Clean Air Act.[5]

EPA and the State's regulations cited above echo the mandate of Section 165(a)(4) of the Clean Air Act that BACT applies not only to pollutants for which regulatory requirements have been imposed, but also to air pollutants for which EPA and the States possess but have not exercised authority to impose regulatory requirements.[6] The regulations provide that BACT applies not only to air pollutants for which there are national ambient air quality standards under Section 109 of the Act, standards of performance for new sources under Section 111 of the Act, or standards under or established by Title VI of the Act (relating to acid deposition control), but also to "[a]ny pollutant that is otherwise subject to regulation under the Act." 40 C.F.R. § 52.21(b)(50). Carbon dioxide is an air pollutant subject to regulation under the Clean Air Act for which KDAQ must comply with BACT requirements.

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[5] The Kentucky Air Quality Regulations have adopted the carbon dioxide monitoring requirements of 40 C.F.R. Part 75. 401 KAR 52:060 Section 2(d) (Acid Rain Permits); 401 KAR 51:160 (NOx requirements for large utility and industrial boilers); 401 KAR 51:210 and 220 (CAIR NOx trading program).

[6] Indeed, EPA and KDAQ lack the authority to promulgate regulations diluting the mandate of Section 165(a)(4) of the Clean Air Act

The proposed permit for the Cash Creek project does not contain a BACT emissions limitation for carbon dioxide. KDAQ has not conducted a BACT analysis for carbon dioxide. KDAQ has made no effort to identify or evaluate available "production processes or available methods, systems and techniques for control of carbon dioxide." See 40 C.F.R. § 52.21. KDAQ has failed to do so. KDAQ conducted and ERORA in its permit application submitted no BACT analysis for carbon dioxide.

KDAQ's failure to conduct a BACT analysis for carbon dioxide and establish an emission limitation for carbon dioxide must be rectified before KDAQ may lawfully issue a permit for the Cash Creel project. Such analysis must necessarily include all operations planned at the site. It appears that ERORA has not provided KDAQ relevant information as part of its permit application sufficient to allow KDAQ to conduct the required analysis. If KDAQ declines to deny the requested permit at this time, KDAQ should request ERORA to provide it with all information necessary to conduct a BACT analysis for carbon dioxide, conduct the required BACT analysis, and issue a revised proposed permit containing the required carbon dioxide BACT emission limitation.

i. The CO2 BACT analysis must consider capture and sequestration.

ERORA must evaluate as BACT for Cash Creek add-on technologies to capture and sequester the greenhouse gas emissions. The U.S. Department of Energy is the primary federal agency working on research and development of CO_2 capture and sequestration technologies, and thus information on carbon capture and sequestration technologies is available on the U.S. DOE website.[7]

Capture. The International Panel on Climate Change ("IPCC") issued a report in 2005 discussing the main options currently available to capture CO_2 from fossil fuel-fired power plants, including pre-combustion capture used at IGCC facilities.[8] According to the IPCC, commercial CO_2 capture systems installed on IGCC facilities can reduce CO_2 emissions by 90% per kilowatt-hour.[9] CO_2 capture systems are available today and have been applied to several small power plants.[10] KDAQ must require ERORA to evaluate the available CO_2 capture systems and to evaluate such CO_2 control systems at the proposed IGCC facility in a proper top-down BACT process focused on maximum reduction of CO_2. ERORA has clearly been evaluating these technologies, as the Cash Creek facility will utilize the Selexol process for sulfur dioxide removal, a process which can also be used to separate carbon dioxide from flue gas. See, e.g., M.I.T. study at p. 34.[11]

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[7] See http://www.fossil.energy.gov/programs/sequestration/capture/.

[8] 2005 IPCC Special Report on Carbon dioxide Capture and Storage, Technical Summary, at 25. See also Chapter 3 of this report. (Both the Technical Summary and Chapter 3 are included as Attachment 2; entire document is available at http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/IPCCSpecialReportonCarbondioxideCaptureandStorage.htm).

[9] *Id.* at 107 (Chapter 3).

[10] *Id.*

[11] Both ERORA and KDAQ completely omitted Selexol's significance for capture of carbon dioxide from the Cash Creek BACT analyses. The BACT analyses instead discuss only the process' ability to remove sulfur dioxide as its main function, as well as regeneration of solvent and production of wastewater steam under the heading "Environmental Evaluation." Cash Creek Application at 4.6.8.3.

Sequestration. Nor has ERORA submitted any evaluation of the potential for transporting and sequestering carbon, such as through injection to enhance recovery of oil and gas from sites nearby the proposed Owensboro location or the construction of a pipeline for injection to other appropriate sites.

ii. The CO2 BACT analysis must set a stringent output-based standard.

Carbon dioxide emissions are directly related to the amount of coal burned. Because electric generating plants are planned and operated to provide a specific amount of electricity, the more coal (or syngas) burned to produce a megawatt of electricity, the more carbon dioxide emitted. Similarly, the less coal burned the lower the emissions of regulated pollutants. In the top-down BACT analysis for each regulated pollutant IEPA must consider output based limits. In short, more efficiency electrical generation must be considered in a BACT determination because it is a "production process[] and available method[], system[] and technique[]... for control of each pollutant." 42 U.S.C. § 7479(3).

As part of the new NSPS standards USEPA adopted output-based standards as a step towards minimizing inefficient and unnecessarily polluting boilers. In the analysis for the new NSPS standards USEPA identified that boiler efficiency can vary enormously.[12] The following table from that same memo and identified as Table 2 describes the range of efficiencies:

Table 2: EIA 2003 Annual Efficiency Values

Percent of Units Operating at or Above Gross Efficiency	**Net Efficiency**
Top 10%	35.0%
Top 20%	34.0%
Top 25%	33.6%
Top 33%	33.2%
Top 50%	32.0%

USEPA further explained that the highest efficiency subbituminous, bituminous, and lignite facilities are 43, 38, 37 percent respectively. In a paper presented by three USEPA combustion experts at the 2005 Pittsburgh Coal Conference they detailed the enormous difference in the efficiency (i.e., the CO2 emissions per ton of coal burned) between sub-critical, super-critical, ultra-supercritical and IGCC coal plants.[13] Following is Table 2 from that paper:

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[12] See Memo from Christian Fellner USEPA to Utility, Industrial and Commercial NSPS File, Gross Efficiency of New Units (February 2005).

[13] See Sikander Khan et al, *Environmental Impact Comparisons IGCC vs. PC Plants* (Sept. 2005). Available at:
http://cfpub.epa.gov/si/osp_sciencedisplay.cfm?dirEntryID=139864&ActType=project&kwords=Waste

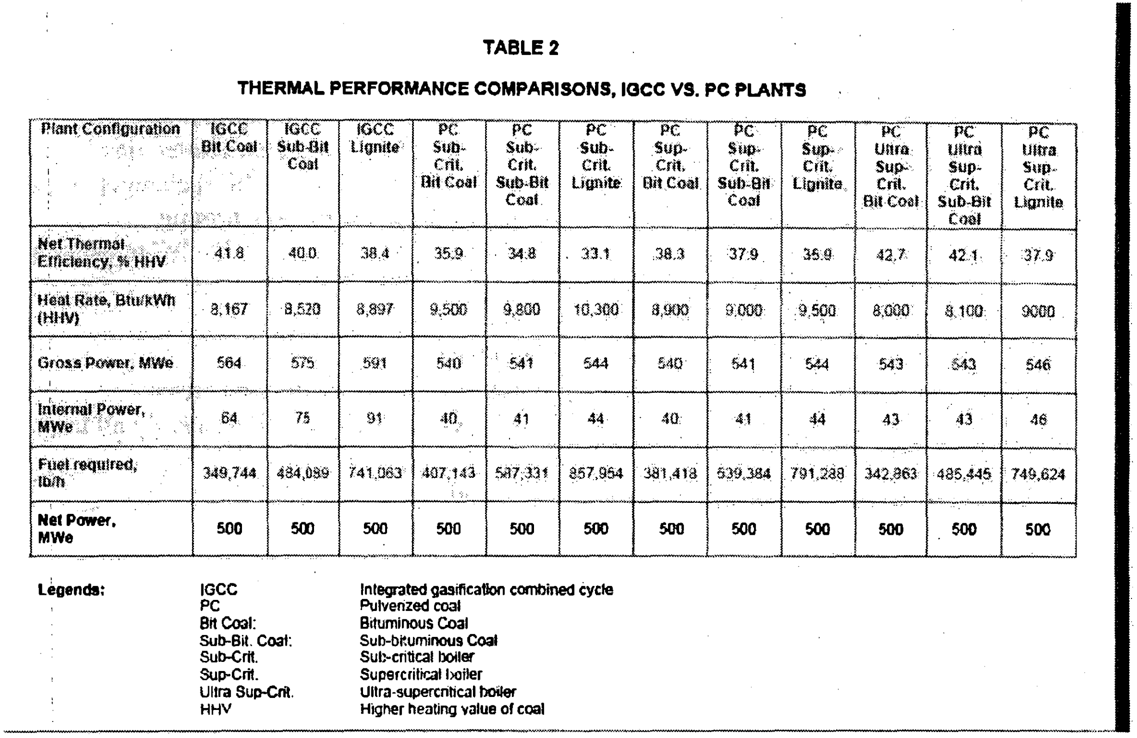

TABLE 2

THERMAL PERFORMANCE COMPARISONS, IGCC VS. PC PLANTS

Plant Configuration	IGCC Bit Coal	IGCC Sub-Bit Coal	IGCC Lignite	PC Sub-Crit. Bit Coal	PC Sub-Crit. Sub-Bit Coal	PC Sub-Crit. Lignite	PC Sup-Crit. Bit Coal	PC Sup-Crit. Sub-Bit Coal	PC Sup-Crit. Lignite	PC Ultra Sup-Crit. Bit Coal	PC Ultra Sup-Crit. Sub-Bit Coal	PC Ultra Sup-Crit. Lignite
Net Thermal Efficiency, % HHV	41.8	40.0	38.4	35.9	34.8	33.1	38.3	37.9	35.9	42.7	42.1	37.9
Heat Rate, Btu/kWh (HHV)	8,167	8,520	8,897	9,500	9,800	10,300	8,900	9,000	9,500	8,000	8,100	9000
Gross Power, MWe	564	575	591	540	541	544	540	541	544	543	543	546
Internal Power, MWe	64	75	91	40	41	44	40	41	44	43	43	46
Fuel required, lb/h	349,744	484,089	741,063	407,143	587,331	857,954	381,418	539,384	791,288	342,863	485,445	749,624
Net Power, MWe	**500**	**500**	**500**	**500**	**500**	**500**	**500**	**500**	**500**	**500**	**500**	**500**

Legends:

IGCC	Integrated gasification combined cycle
PC	Pulverized coal
Bit Coal:	Bituminous Coal
Sub-Bit. Coal:	Sub-bituminous Coal
Sub-Crit.	Sub-critical boiler
Sup-Crit.	Supercritical boiler
Ultra Sup-Crit.	Ultra-supercritical boiler
HHV	Higher heating value of coal

To minimize the emissions of carbon dioxide KDAQ should insert a permit provision requiring the project proponent to maintain a net thermal efficiency at or above 41 percent, or set an emission rate limit in pounds per MWh that is based on 41% efficiency. Such a term would minimize both the emissions of regulated pollutants and the collateral emissions of carbon dioxide.

b. The Permit Must Ensure that the Facility Will Not Emit Carbon Dioxide at Such Quantities or Duration as to be Harmful to the Health and Welfare of Humans, Animals and Plants.

Carbon dioxide emissions and ensuing global warming effects clearly pose a threat to the health and welfare of humans, animals, and plants. The permit thus must ensure that emissions of carbon dioxide from the proposed facility are adequately controlled to avoid such impacts, pursuant to 401 KAR 63:020, "Potentially Hazardous Matter or Toxic Substances." Neither the applicant nor KDAQ complied with this requirement by considering the impacts of carbon dioxide from the Cash Creek project. See App. Section 8; Statement of Basis p. 12 of 51.

As the permit states, the proposed project is subject to 401 KAR 63:020. Permit at pp. 2 and 12 of 51. The regulation defines "potentially hazardous matter or toxic substances" as "matter which may be harmful to the health and welfare of humans, animals, and plants, including, but *not limited to*, antimony, arsenic, bismuth, lead, silica, tin, and compounds of such materials." Id. at Section 2(2) (emphasis added). According to the American Heritage Dictionary, "matter" is "[s]omething that has mass and exists as a solid, liquid, gas, or plasma."[14] Carbon dioxide clearly fits this definition. Furthermore, there can be no doubt that carbon dioxide emissions and the ensuing acceleration of global warming pose serious danger to humans and the environment. The U.S. EPA has concluded that "[a] few degrees of warming increases the chances of more frequent and severe heat waves, which can cause more heat-related death and illness,"[15] as well as "more frequent droughts, ... greater rainfall, and possibl[e] change[s in] the strength of storms."[16] These are only a few of the threats posed by global warming.

The IPCC identifies the following impacts as either "likely" or "very likely" to occur as CO2 concentrations in the atmosphere increase:

- Higher maximum temperatures over most land areas;
- Higher maximum temperatures and more hot days over nearly all land areas;
- Higher minimum temperatures and fewer cold days and frost days over nearly all land areas;
- Reduced diurnal temperature range over most land areas;
- More intense precipitation events over many areas; and
- Increased summer dry conditions and associated risk of drought over most midlatitude continents.[17]

The extent of negative global warming impacts will depend on the amount of CO2 emitted into the atmosphere. However, the fact of those negative impacts is certain. The National Academies of Science, in the report "Climate Change Science" (2001), found that the "risk [to human welfare and ecosystems] increases with increases in both the rate and the magnitude of climate change."[18] Simply put, the more CO2 humans release into the atmosphere, the more serious the impacts on the environment.

In 2001, the U.S. Global Change Research Program released *Climate Change Impacts on the United States: The Potential Consequences of Climate Variability and Change* (*National Assessment*) predicting effects of climate change for each region in the U.S.[19] The report was authored by scientists from the U.S. Geological Survey, USDA Forest Service, and numerous universities across the nation. The *National Assessment* shows that "the changes in the simulated heat index for the Southeast [including Kentucky] are the most dramatic in the nation." *National Assessment Overview*, p. 48. With the increased heat, air pollution is also likely to worsen.[20] "Without strict attention to regional emissions of air pollutants, the undesirable combination of extreme heat and unhealthy air quality is likely to result." *National Assessment Overview*, p. 55.

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[14] "matter." (n.d.). *The American Heritage® Dictionary of the English Language, Fourth Edition*. Retrieved June 08, 2007, from Dictionary.com website: http://dictionary.reference.com/browse/matter

[15] U.S. EPA, climate change website, last updated on April 6, 2001, http://www.epa.gov/globalwarming/faq/fundamentals/html

[16] U.S. EPA, climate change website, last updated on April 6, 2001, http://www.epa.gov/globalwarming/faq/moredetail/html

[17] International Panel on Climate Change, *Climate Change 2007: The Physical Science Basis, Summary for Policy Makers*, hereinafter IPCC 2007 (attached and available at www.ipcc.ch)

[18] Committee on the Science of Climate Change, National Research Council, "Climate Change Science: An Analysis of Some Key Questions," National Academies Press (2001)

[19] National Assessment Synthesis Team (2000), available at http://globalchange.gov/pubs/nast_2000.html

[20] IPCC, Third Assessment Report, "Climate Change 2001: Impacts, Adaptation, and Vulnerability," p. 764, available at http://www.grida.no/climate/ipcc_tar/

In other words, harmful air quality will accompany the heat increases predicted for Kentucky as a result of global warming.

According to the National Assessment, effects on Kentucky, as with the rest of the Southeast, are expected to be significant in terms of human health: "of concern...are the effects that elevated surface temperatures have on human health as a result of prolonged or persistent periods of excessive summertime heat events coupled with droughty conditions." *National Assessment*, p. 146.[21] Heat is not the only expected cause of health problems in Kentucky's region. Decreases in water quality are also expected, and "effects on surface waters of changes in precipitation have important health implications in the region. Increased precipitation promotes the transportation of bacteria as well as other pathogens and contaminants by surface waters throughout the region." Id. at p. 159. Unless releases of global warming pollution are curbed and then significantly decreased, global warming pollution will pose significant threats to the health, welfare, and economy of Kentucky.

Thus, KDAQ must make an individualized determination as to the proposed project's carbon dioxide emission potential and the adequacy of controls and/or procedures for controlling carbon dioxide pursuant to 401 KAR 63:020. The agency must do its part to prevent these dire health and environmental threats by prohibiting, or at a minimum mitigating, the 3-4,000,000 tons of CO2 pollution that would result from the proposed project annually. Said another way, this project would add the carbon emissions from adding approximately 500,000 cars per year for each of the next fifty years.[22]

In light of the serious adverse impacts of carbon dioxide emissions on human health and welfare, property, and the environment, KDAQ cannot lawfully refuse to exercise its authority 401 KAR 63:020 to eliminate or limit carbon dioxide emissions in taking action on the proposed Cash Creek project permit. Indeed, the Supreme Court in Massachusetts v. EPA, even without the benefit of the most recent IPCC Reports, noted that the "[t]he harms associated with climate change are serious and well recognized." 127 S. Ct. at 1455. The Supreme Court also acknowledged "the enormity of the potential consequences associated with man-made climate change." Id. at 1458. The Massachusetts v. EPA decision makes clear that KDAQ may rely on 401 KAR 63:020 to eliminate or limit carbon dioxide emissions from the Cash Creek permit.

c. The BACT Limits are Not Supported.

i. Combustion Turbine versus Gasifier Heat Input

As a general matter, the permit record does not adequately document how the numeric limits were determined. The permit sets limits based on heat input to the combustion turbine. See SOB at Table 4-13; Permit at pp. 3-4 of 51. The application proposes limits based on heat input to the gasifier. App. Section 4. The SOB does not provide any background information on or calculations showing how KDAQ converted the gasifier-heat input limits to combustion turbine-heat input limits.

ii. Cleaner Fuels

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[21] Chapter 5, "Potential Consequences of Climate Variability and Change for the Southeastern United States"

[22] See EPA Office of Air and Radiation. Factsheet EPA420-F-00-013 "Average Annual Emissions and Fuel Consumption for Passenger Cars and Light Trucks: Emission Facts.

Cleaner Fuels. BACT explicitly requires a comprehensive analysis of control options that results in "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation [under the PSD program]... achievable for [a] facility through...*fuel cleaning* [and] *clean fuels*..." 42 U.S.C. § 7479(3) (emphases added). In other words, "the 1990 Clean Air Act amendments...expressly require consideration of clean fuels in selecting BACT" and the EPA considers clean fuels as "an available means of reducing emissions to be considered along with other approaches to identifying BACT level controls." In re: Inter-Power of New York, Inc., 1994 EPA App. LEXIS 33, 40, 5 E.A.D. 130, 134 (E.A.B. 1994)[23]. Longstanding EPA policy with regard to BACT has "required that a permit writer examine the inherent cleanliness of the fuel." Inter-Power at 134. KDAQ's policy likewise is to consider the use of clean fuels in BACT determinations. *See* Andrews Dep. taken in Sierra Club, et al. v. EPPC, File No. DAQ-27602-042, Permit No. V-02-043 R2, at pp.39, cited in Petitioners' Memorandum In Support of Motion for Summary Judgment On Counts 2, 4, 5, 7, 8, 10, 11, 12, 15, 16, 17, 18, 24, and 25, submitted Sept. 1, 2006.[24]

The permit contains separate NOx limits for firing natural gas versus syngas. See below, NOx BACT, for comments on natural gas and NOx BACT.

An available clean fuel that has received no discussion in the agency's top-down BACT analysis is biomass. Co-firing biomass at an IGCC plant can result in lower emissions of NOx, SO2, and PM/PM10.[25]

There are numerous examples of coal plants co-firing biomass that should be considered in the top-down BACT analysis. For example, the St. Paul heating plant burns approximately sixty percent biomass and forty percent coal.[26] The biomass is primarily waste wood from tree trimmings in the Twin Cities and other industrial activities. The Xcel Bay Point power plant in Ashland, Wisconsin, also burns large amounts of wood waste, consisting primarily of saw dust. Burning biomass also is consistent with Governor Fletcher's recent commitment to expand the use of biofuels.

The U.S. Department of Energy has urged federal facility managers to consider co-firing up to 20 percent biomass in existing coal-fired boilers.[27] In the Netherlands, the four electricity generation companies (EPON, EPZ, EZH and UNA) have all developed plans to modify their conventional coal fired installations to accommodate woody biomass as a co-fuel.[28] The types of available biomass include wood wastes, agricultural waste, switchgrass and prairie grasses.[29]

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[23] "The phrase 'clean fuels' was added to the definition of BACT in the 1990 Clean Air Act amendments. EPA described the amendment to add 'clean fuels' to the definition of BACT at the time the Act passed, 'as *** codifying its present practice, which holds that clean fuels are an available means of reducing emissions to be considered along with other

[24] "[fuel cleaning and/or clean fuels are] just part of the BACT analysis."

[25] See, e.g., Tampa Electric Company, "Biomass Test Burn Report Polk Power Station Unit 1," (Apr. 2002) at p. 10 (showing lower NOx and SO2 emissions for biomass test burn periods versus baseline), available at http://www.treepower.org/cofiring/main.html, As KY measures PM/PM10 to include condensable PM, then a reduction in NOX and SO2 would be a reduction in PM/PM10 also.

[26] http://www.districtenergy.com/

[27] http://www1.eere.energy.gov/biomass/pdfs/33811.pdf

[28] http://www.eeci.net/archive/biobase/B10252.html

[29] http://www.nsf.gov/news/news_summ.jsp?cntn_id=108206

iii. PM BACT

The permit sets a limit for filterable PM/PM_{10} of 0.0085 lb/MMBtu and a limit for total particulate/PM_{10} of 0.0217 lb/MMBtu. Permit at p. 4 of 51.

Averaging Time. As an initial matter, these limits lack an averaging time. The application proposes a 3-hour averaging time. App. at p. 4-36. This averaging time should be included in the permit.

Basis for Total PM/PM_{10} Limit. The proposed filterable PM limit is nearly identical to the filterable PM limit in the final PSD permit for the EKPC Spurlock 4 CFB unit. However, the proposed total PM limit here is higher than the total PM limit for the Spurlock 4 facility (0.012 lb/MMBtu). The applicant does not provide a total PM limit that includes condensable particulate matter, but instead discusses condensable matter from IGCC technology and proposed a method for establishing a total PM_{10} limit based on actual operating data. App. at 4-37. KDAQ included a numeric total particulate/PM_{10} permit limit of 0.0217 lb/MMBtu[30], but failed to provide the basis for this limit in the Statement of Basis. KDAQ must explain how it determined the PM/PM_{10} Total limit.

Combination/Post-Combustion Controls. The PM BACT analysis fails to consider post-combustion controls in combination with pre-combustion IGCC wet syngas scrubbing. Contrary to the applicant's assertion, BACT does not automatically allow the rejection of all technologies other than the single control associated with "highest removals" selected by the applicant. *See*, e.g., App. at 4-34 and 4-38. Rather, combinations of controls must be considered. Considering only a single control option is both in conflict with the definition of BACT and with common practice. The definition of BACT uses the plural for control options that must be analyzed towards achieving the "maximum degree of reduction...achievable" (BACT is based on "application of production processes or available methods, systems, and techniques.") Nowhere does the definition of BACT allow the selection of a single control option to the exclusion of all others. Rather, available control options are only rejected in a top-down analysis process. The EAB has held numerous times that BACT must reflect an assessment of all available options to achieve the maximum degree of reduction of each pollutant subject to regulation, and should not be limited to a comparative assessment of add-on controls.[31] In addition, permits in practice set BACT limits based on use of several control options. In fact, the applicant itself proposed, and KDAQ accepted, a NO_x BACT limit based on use of combustion control (diluent injection) *and* post-combustion control (SCR). *See* App. at pp. 4-57 to 4-59; SOB at p. 26; Permit at p. 3 of 51.

The applicant mentions several post-combustion PM control technologies, but provides neither technical nor economic reasons justifying why post-combustion PM control in combination with pre-combustion IGCC wet syngas scrubbing does not constitute BACT. KDAQ must deny the

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[30] See, e.g., SOB at p. 19 (discussing PM/PM10 (filterable) limit of 0.0063 lb/MMBtu) and 26 (PM/PM10 Total limit of 0.0217 lb/MMBtu).

[31] *See* In re Knauf Fiber Glass, Gmbh, 8 E.A.D. 121, 129 (EAB 1999) (Knauf I) (citing NSR Manual at B.10, B.13); In re Old Dominion Elec. Coop., 3 E.A.D. 779 (EAB 1992); Inter-Power of New York, 5 E.A.D. at 135-136; In re CertainTeed Corp., 1 E.A.D. 743 (EAB 1982) at 2-5.

permit and request that the applicant provide such justification in a proper top-down BACT analysis or propose new PM limits reflecting the use of post-combustion controls in addition to pre-combustion wet syngas scrubbing.

PM2.5 BACT. The Draft Permit does not include a BACT limit for PM2.5 emissions. Nor does it appear that KDAQ even considered such a limit. This is unlawful and must be corrected before a PSD permit can issue. The federal PSD program requires a BACT limit "for each pollutant subject to regulation under the Act that it would have the potential to emit in significant amounts." 40 C.F.R. § 52.21(j)(2). PM2.5 is "a pollutant subject to regulation under the Act" because EPA established a NAAQS for PM2.5 in 1997. 62 Fed. Reg. 38711; 40 C.F.R. § 50.7. Moreover, PM2.5 will be emitted from this facility in a "significant" amount because it will be emitted at "any emission rate." 40 C.F.R. § 52.21(b)(23)(ii). For these reasons a BACT limit for PM2.5 is required. 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j). Nevertheless, the Draft Permit does not contain a BACT limit for PM2.5 emissions. This is a deficiency that must be corrected before a final PSD permit can issue.

We are aware that EPA issued guidance providing that sources would be allowed to use implementation of a PM_{10} program as a surrogate for meeting $PM_{2.5}$ NSR requirements. John Seitz, "Interim Implementation for the New Source Review Requirements for PM[2.5]," (October 23, 1997). The purpose of that guidance was to provide time for the development of necessary tools to calculate the emissions of $PM_{2.5}$ and related precursors, adequate modeling techniques to project ambient impacts, and $PM_{2.5}$ monitoring sites. 70 Fed. Reg. 65984, 66043 (Nov. 1, 2005). It does not propose, however, to substitute PM10 BACT as a PM2.5 BACT. Furthermore, EPA has resolved most of the modeling and ambient air impact analysis issues underlying the memo. *Id.* More importantly, the guidance memo clearly contravenes the law. In order to protect public health and the environment, the regulations must be implemented as written.

PM CEMS. The permit is required to have Compliance Assurance Monitoring for PM10, as the facility will emit over 100 tpy pf the pollutant. See 40 CFR Part 64. The draft permit, however, makes no mention of CAM for PM10. This omission must be remedied.

In 2004, EPA promulgated final performance specifications, PS-11, for installation, operation, maintenance, and quality assurance of continuous particulate matter emission monitoring systems (PM-CEMS). Since the PSD program is supposed to be technology forcing, requiring a PM-CEMS to ensure compliance with the PM permit limits would be consistent with that goal. Moreover, utilities can emit large amounts of particulate matter when pollution sources and/or control devices are not functioning properly and PM-CEMS can help identify such compliance issues.[32] KDAQ recently required the use of a PM CEMS in the PSD permit for the EKPC Spurlock 4 CFB project. There is extensive experience of PM CEMS on coal plants as a result of numerous NSR settlements around the country. We urge KDAQ to require the use of a PM CEMS and that a PM CEMS is required for determining compliance with the permit's PM filterable limit.

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[32] *See* USEPA Region 7 Sunflower PSD Comments.

Bulk Handling, Storage, Processing and Loadout Operations. The top-down BACT analysis must start with the limits that agencies have required in other permits, including the limit of no greater than 0.005 grains/dry standard cubic foot and no visible emissions, based on the permit the Illinois Environmental Protection Agency issued for the proposed Indeck-Elwood facility. See Indeck Permit at p. 27, Attachment 3. In contrast to these acceptable BACT limits, KDAQ failed to include an emission limitation for Unit 7 (coal pile). Permit at p. 25 of 51. Instead, the applicant and agency rely solely on use of certain controls and cite an approximate expected removal efficiency. BACT is an emission limitation. Controls like baghouses and methods such as "compaction" and "water suppression control methods" therefore do not constitute BACT, but are descriptions of how a source might reach a BACT limit. The permit should include numeric limits on material handling emissions like those in Indeck-Elwood. In addition, the permit relies on vague language regarding "reasonable precautions" as operating limitations for Unit 7. Terms such as "reasonable precautions" are unenforceable.[33] See Permit at p. 25 of 51. The emission limitation of 20 percent opacity for Unit 6 is also insufficient in light of the zero visible emissions limit in the Indeck-Elwood Permit. Finally, we were not able to review the emissions modeling for these sources within the limited public comment period. If the modeling did not use the maximum theoretical emission rate for each source, the agency must reject the modeling demonstration and require the applicant to resubmit proper modeling. See NSR Manual at C.45-46.

Cooling Towers. The Draft Permit establishes a limit that requires the cooling tower to "utilize 0.0005% Drift Eliminators." Draft Permit, at 54. This provision is not BACT, and it is not an enforceable emission limit. First, a drift efficiency control rate, by itself, does not correspond to a PM emission rate. PM is formed by dissolved solids in the circulating water. The drift is emitted from the cooling towers, the water is evaporated, leaving the solids that become particulate matter. The percent of the circulating water that is emitted (drift rate), by itself, is not a measure of particulate emissions.

Second, an emission rate, calculated from the drift fraction, total dissolved solids ("TDS") and circulating water flow rate, should be established as the permit limit for the cooling tower, based on a topdown BACT analysis. The draft permit sets a drift rate and requires that TDS be measured, but it falls short due to the lack of an emission rate or maximum TDS level in the circulating water flow. While a TDS limit of 21,000 parts per million is a start, it is only sufficient as BACT if the ppm concentration is the lowest concentration achievable through application of processes and available methods, systems and techniques for reducing emissions, 42 U.S.C. 7479(3), e.g., purification and filtering of the circulating water. PM emissions from the cooling tower can be further reduced by reducing or eliminating the dissolved solids in the circulating water. Absent a showing that further reduction of solids in the circulating is not technically or economically feasible, the 0.0005% drift efficiency rate and 21,000 ppm TDS limit do not constitute BACT. If KDAQ relies on cooling tower drift eliminators and a limit on suspended solids in the circulating water to establish BACT, the Permit must also include a circulating water flow rate based on the lowest concentration achievable

Third, with regard to testing, the permit must require periodic retesting of drift rates on a more frequent basis than upon permit renewal, as drift eliminator performance degrades over time.

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[33] See U.S. EPA Region 9, "Title V Permit Review Guidelines: Practical Enforceability," (Sept. 1999).

Fourth, a cooling tower with drift eliminators is not the least polluting technology, and does not constitute BACT. Use of an air cooled condenser ("ACC"), an alternative method, system or technique of cooling within the definition of BACT, is available and has lower PM emissions than a cooling tower with drift eliminators. ACCs have been used on large coal-fired power plants for over 25 years. The 330 MW Wyodak coal-fired power plant in Wyoming has successfully operated with an ACC for over 25 years. The largest ACC-equipped coal fired power plant in the world, the 4,000 MW Matimba facility in South Africa, has been operating successfully for over 10 years. Two coal-fired units in Australia with condenser heat rejection rates nearly identical to that proposed for Weston Unit 4 have been operational since 2002. A number of new coal-fired power plants have been proposed in New Mexico over the last three years. In all cases the project proponents have voluntarily incorporated ACC into the plant design to minimize plant water use. A 36 MW pulverized coal unit in Iowa, Cedar Falls Utilities Streeter Station Unit 7, was retrofit with dry cooling in 1995 due to highway safety concerns caused by the wet tower plume in winter. The use of dry cooling is well established. The application of an AAC would eliminate nearly all of the PM emissions from the cooling process. Therefore, unless AAC can be rejected in a top-down BACT analysis, based on site-specific collateral impacts, it must be used to establish BACT. AAC cannot be eliminated based on cost, especially because it must be compared to the total cost of a cooling tower, including the towers, raw water clarification system, and intake structures. Moreover, use of AAC has additional environmental benefits, including no water withdrawals for cooling, no brine discharge to river, no aesthetic issues related to visible vapor plumes, no cooling tower drift emissions or particulate deposition.

Other potential options to reduce PM/PM10 emissions from the cooling process include a plume abated tower and a wet/dry system. Like ACC, these alternative processes result in lower emissions and, therefore, must be considered in a top-down BACT analysis. The applicant's analysis fails to identify, much less consider these options for reducing PM/PM10 emissions. A revised BACT analysis must be conducted for the cooling process.

Fifth, the draft permit includes the term "reasonable precautions" as both an operating and an emission limitation. This term is vague and unenforceable. In its stead, the permit should include explicit language describing the measures to be taken with respect to the cooling tower to prevent particulate matter from becoming airborne.

iv. NO_x BACT

The permit sets limits for NO_x of (a) 0.0331 lb/MMBtu during any rolling three-hour average when firing syngas, and (b) 0.0246 lb/MMBtu during any rolling three-hour average period when firing natural gas.

Fuel-based limits. While the permit sets two different limits for syngas and natural gas, the applicant proposed a single NO_x limit of 0.0246 lb/MMBtu for both fuels. The SOB does not explain the agency's decision to set two different limits when the applicant proposed a single limit for both fuels. While the applicant included a footnote to its proposed NO_x limit, the application available for public review did not contain any text for this footnote. See App. p. 4-

59 (footnote 35 empty). Absent any justification for treating the two fuels differently, BACT for NO_x should be the single numeric limit for both fuels proposed by the applicant.

Furthermore, as noted above, a top-down BACT analysis must consider the use of cleaner fuels, including natural gas and biomass. Since the facility is specifically designed to be able to fire natural gas, burning gas would not "redefine the source." The limit for firing natural gas is lower than that for syngas. In addition, as noted above, co-firing biomass at an IGCC facility is technically feasible and results in lower NOx emissions than firing syngas alone. Thus, NOx BACT must be based on consideration of firing natural gas and biomass.

The facility also is designed to burn natural gas in combination with syngas. By burning a mix of natural gas with syngas, or 100% natural gas, the source could lower both the pound-per-MMBtu emission rate and the hourly emission rate for each of the regulated pollutants, including NO_x. Thus the BACT analysis must consider mixing natural gas with syngas and burning 100% natural gas. If the cost effectiveness of combusting natural gas, or a combination of gas and syngas, is within the range generally accepted as cost-effective for similar sources (i.e., under $10,000 per ton of pollutant removed), the BACT limit for NOx must be established based on a BACT analysis that factors in natural gas. Notably, burning 100% natural gas could allow the source to avoid purchasing some of the most expensive equipment, including the gasifier..

Lower NOx limit. Furthermore, while we commend ERORA for analyzing and selecting Selective Catalytic Reduction ("SCR") in its NO_x BACT analysis, the proposed technology can achieve lower than the proposed permit limits of 0.0331 lb/MMBtu and 0.0246 lb/MMBtu. The applicant states that the "most stringent [NO_x] emission limit" for existing and proposed IGCC sources is 0.059 lb/MMBtu from the Southern Illinois Clean Energy Center facility. App. at 4-30. The cited facility will not employ SCR, a post-combustion control, to limit NO_x emissions. SICEC therefore represents the "uncontrolled" emissions baseline for purposes of assessing SCR for an IGCC facility. The applicant acknowledges that SCR alone can achieve 90% "add-on" control efficency for NO_x. App. at 4-57. Given an uncontrolled baseline of 0.059 lb/MMBtu NO_x and an add-on control efficiency of 90% for SCR, the NO_x BACT limit for Cash Creek should be 0.0059 lb/MMBtu.

v. Sulfur dioxide (SO2) and sulfuric acid mist ("SAM") BACT

The applicant asserts that a single analysis is required to determine BACT for SO2, SAM and condensable PM. App. at p. 4-42.

BACT requires a separate analysis for each regulated pollutant. First, the applicant is incorrect as a legal matter. BACT is an "emission limitation" that is determined on a "case-by-case basis" for "each pollutant subject to regulation under Act." 40 C.F.R. 52.21(b)(12). Thus, while there may be overlap in the "control devices" discussed in the BACT analysis for each pollutant (see App. at 4-42), separate BACT analyses must be conducted to arrive at proper emission limitations. Separate analysis is necessary to take into account the chemical and physical differences among the pollutants. Absent separate analyses for each pollutant, the BACT limits are not supported. As the Applicant's BACT analysis for SO2 and SAM directly discusses only "BACT Selection for SO2,"App. at pp. 4-45 to 4-56, the BACT analysis for SAM is insufficient.

A single BACT analysis for SO2 and SAM is technically unjustified. Second, as a technical matter, the applicant's combined SO_2-SAM BACT analysis fails to explain why a combined analysis is justified in light of the limits proposed for the Elm Road facility. The application sites Elm Road as having the most stringent existing or proposed limit for SAM, at 0.00005 lb/MMBtu (note that we believe this limit should be 0.0005 lb/MMBtu). App. at 4-30. The accompanying SO2 limit proposed for Elm Road was 0.03 lb/MMBtu. The H2SO4 and SO2 BACT limits proposed by the applicant for Cash Creek are 0.0026 lb/MMBtu and 0.0117 lb/MMBtu, respectively. Given that the Elm Road project has a lower SAM but a higher SO_2 limit than the limits proposed for Cash Creek, it is not clear that a single BACT analysis is technically appropriate for the two pollutants.

For comments on the condensable PM, see above.

1. SO2 BACT

Clean fuels. The SO2 limit consists of a limit on the exhaust gas based on syngas fuel not to exceed 0.8 percent sulfur by weight. There does not appear to be any clean fuel consideration applied to this standard, For example, as described above in the PM BACT discussion, there does not appear to have been any consideration of the use of natural gas and/or biomass either in whole or in part as a clean fuel control method to minimize the emissions of criteria pollutants, including sulfur dioxide. The SO2 top-down BACT determination for the combustion turbines must include consideration of natural gas and gasified biomass.

2. SAM BACT

The Draft Permit contains a SAM limit of 0.0026 lb/MMBtu. Permit at p. 4 of 51. As an initial matter, the limit lacks an averaging time. The application proposes a three-hour rolling average. Application at 4-56. In addition, this purported BACT limit appears high. As noted above, the the application lists the Elm Road facility as having the most stringent existing or proposed limit for SAM, at 0.00005 lb/MMBtu (0.0005 lb/MMBtu). The application provides no justification why this limit cannot be achieved at Cash Creek. In addition, in 2002, the AES Puerto Rico permit for a coal-fired CFB plant had a SAM emission limit of 0.0024 lb/MMBtu, which is lower than the proposed limit for Cash Creek. This facility will include a Wet Eletrostatic Preciptator ("WESP") to control particulate matter; SOB at 16, similar to the Trimble facility recently proposed by Louisville Gas & Electric However, the SOB only lists the WESP under control technology for PM/PM10. Id. We urge KDAQ to consider a lower SAM limit based on the use of a WESP in a top-down BACT determination for Cash Creek. As put forth above, BACT requires consideration of combinations of controls, including pre- and post-combustion controls. The use of WESPs are now common on new coal plants burning high-sulfur coal (see e.g., the Trimble facility and the Prairie State facility in Illinois) and we are not aware of any obvious technical reasons why a WESP could not be used on an IGCC plant as well.

vi. Visible Emissions

The permit contains an opacity limit of 20%, except that a maximum of twenty-seven percent for not more than 1 six-minute per hour. Condition B.2(d).

This emissions limit is based on the NSPS standard, and not on BACT level control. Id. (citing 40 CFR 60.42Da (b)).. The Draft Permit is therefore deficient. The permit must contain a visible emission limit for regulated pollutants (i.e., PM and H2SO4)[34] that is based on the maximum degree of reduction achievable with the best pollution control option for the proposed facility. A PSD permit must require BACT for all regulated pollutants. BACT is defined as an "emissions limitation, *including a visible emission standard...*" 42 U.S.C. § 7479(3) (emphasis added); 40 C.F.R. § 52.21(b)(12). Although a BACT limit for PM or SAM typically includes an emission rate limit (i.e., pounds per hour or pounds per million Btu heat input), a BACT limit must nevertheless also "includ[e] a visible emission standard." Id.

Other recent coal plant permits include visible emission as part of the BACT limits for those facilities. For example, the Springerville facility in Arizona has a BACT limit of 15% opacity, and the Mid-America facility in Council Bluffs has an opacity limit of 5 percent..[35] The Wisconsin Department of Natural Resources set a 10% opacity limit as BACT for the Fort Howard (Fort James) Paper Company's 500 MW CFB boiler. The Minnesota Pollution Control Board also considered the issue and determined that a 5% opacity limit should be established based on BACT. The maximum achievable visible emission reduction for a combustion turbine, however, is much lower than 20% opacity. For example, the JEA Northside CFB in Jacksonville, Florida, conducted a compliance test during the summer of 2002, while burning high-sulfur coal, and measured opacity of less than 2%.[36] Testing done by Black & Veatch for the Department of Energy showed visible emissions at the JEA facility of 1.1% and 1.0% opacity.[37] Also, the City of Springfield agreed to a lower opacity limit.

The final permit must contain BACT limits that include a visible emission standard for the combustion turbines. The BACT limits for PM and SAM must include a visible emission limit of no more than 2% opacity based on the results of testing at the JEA Northside facility.[38] In other words, if opacity at a CFB plant can be limited to less than 2 percent opacity, the project applicant must explain why it cannot meet such a limit when firing syngas, a fuel with lower particulate matter emissions than solid coal.

vii. Startup, Shutdown, and Malfunction BACT

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[34] A visible emission standard is a limit on "light scattering particles," which include both fine particulate matter ("PM") and sulfuric acid mist ("SAM") aerosols. Both PM and SAM are regulated under PSD and, therefore, a complete PSD permit must contain a BACT limit which includes a visible emission limit based on BACT for PM and SAM.

[35] See Iowa DNR Permit No. 03-A-425-P, §10a, available online at http://aq48.dnraq.state.ia.us:8080/psd/7801026/PSD_PN_02-258/03-A-425-P-Final.pdf, last visited October 28, 2005

[36] William Goodrich, et al., Summary of Air Emissions from the First Year Operation of JEA's Northside Generating Station, Presented at ICAC Forum '03, p. 16

[37] See Black & Veatch, Fuel Capability Demonstration Test Report 1 for the JEA Large-Scale CFB Combustion Demonstration Project, DOE Issue Rev. 1 p. 12 (Sept. 3, 2004)

[38] See Goodrich, *supra*, p. 16

1. Sulfur Recovery Unit

The draft permit completely exempts the sulfur recovery unit from its limit of 100 ppm by volume (dry basis) at 0% oxygen on a three hour basis during periods of startup and shutdown. Permit at p. 17 of 51. There are no obvious reasons why the permit could not require the use of natural gas during periods of startup and shutdown of the sulfur recovery unit and thereby avoid the firing of high-sulfur syngas during these periods. Accordingly, the use of natural gas must be considered in setting a top-down SO2 BACT limits for the sulfur recovery unit during periods of start up and shutdown. The existing limit does not constitute BACT.

2. Combustion Turbines

The draft permit does not appear to have any meaningful start up or shutdown limits for the combustion turbines for any pollutants. The permit as written exempts periods of start up and shutdown from any input-based limits for PM (both filterable and total), NOx and mercury[39], and SO2[40]. The only other applicable limits to these pollutants appear to be the annual limits.

Annual limits are not sufficient to meet the requirement that a PSD permit include BACT startup and shutdown limits for each regulated pollutant and protect air quality standards. See *In re Indeck-Elwood, LLC*, PSD Appeal No. 03-04 (EAB September 27, 2006).[41] In setting lawful startup and shutdown BACT limits KDAQ must consider the use of cleaner fuels, *i.e.* other than syngas, such as natural gas and/or gasified biomass. If KDAQ issues a new permit with numeric startup and shutdown BACT limits for each regulated pollutant – as we believe it must -- the public must get an opportunity to comment on such new limits prior to their being finalized.

The permit also refers to a startup-shutdown plan submitted to the agency. Permit at p. 4 of 51. It is not clear whether this plan was made available to the public as part of the permit record. As commenters have not reviewed the plan, it is assumed that the plan contains so-called "narrative" limits to allegedly serve as BACT. Narrative limits are allowed to serve as BACT only where the agency determines on the record 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." 401 KAR 51:001 Sec. 1(25)(c); 40 C.F.R. § 51.166(b)(12); *In re Indeck-Elwood, LLC*, PSD Appeal No. 03-04 (EAB September 27, 2006)("Indeck-Elwood"). If such a standard is set as BACT, the standard must establish "the emissions reduction achievable by implementation of the design, equipment, work practice or operation." Id. Narrative limits, in contrast, are not permitted where the limitations cited by the agency are principally design and operational constraints, such as the inability of air pollution control technology to operate at low temperatures during startup and shutdown. *Indeck-Elwood* at p. 70. Thus, KDAQ must make an on the record determination that these standards are met in order for the startup shutdown plan to properly serve as BACT, as well as set the accompanying emissions reduction achieveable for

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[39] Section B Units 01 and 02, Condition 2(h)

[40] Section B Units 01 and 02, Condition 4(b) – periods of startup and shutdown excluded from 3-hour rolling average exceedances; Section B Unit 05, Condition 2(c).

[41] Deciding whether exemption from *short-term* BACT limits and inclusion of vague, to-be-determined narrative limits comply with BACT. The starting point for the EAB's decision was the statutory and regulatory definition of BACT. Under the definition, BACT requirements cannot be "waived or otherwise ignored during periods of startup and shutdowns." *Indeck-Elwood* at p. 66. .

each pollutant under the narrative limits. Absent such justification, KDAQ must set numeric BACT limits for all regulated NSR pollutants. In addition, as a critical part of the permit's narrative limits for startup and shutdown, the plan should be attached to the permit and incorporated by reference as an enforceable component of the permit itself.

In addition. Section E contains a catchall "good practices" provision that applies during all operations, including periods of startup and shutdown. Permit at p. 37 of 51. The condition states that "Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source." As the determination will be based on "information available to the Division" that is not available to the public, the condition is unenforceable by the public and thus is in violation of Title V requirements.

3. Terms Should Be Clearly Defined

The term "startup" should be defined as "the period beginning with ignition and lasting until the equipment has reached a continuous operating level and operating permit limits."[42] The term "shutdown" should be defined as "the period beginning with the lowering of equipment from base load and lasting until fuel is no longer added to the combustion turbine and combustion has ceased."[43]

II. THE PERMIT CONTAINS PROVISIONS THAT ARE NOT ENFORCEABLE

a. Continuous compliance.

Conditions throughout the permit fail to state that continuous monitoring systems will only be used as "the indicator of continuous compliance" and that exceedances of limits as measured by the systems will only trigger an investigation. See, e.g., Condition B.4(b). These conditions render the CAM provisions inadequate to ensure continuous compliance with permit limits. The EPA has objected to Title V permits in Region 4 for failure to include explicit statements that the indicators are not set as enforceable limits. For example, in the Tampa Electric Company's F.J. Gannon Station case, the EPA objected to the Title V permit, stating:

> While the permit does include parametric monitoring of emission unit and control equipment operation in the O&M plans for these units... the parametric monitoring scheme that been specified is not adequate. The parameters to be monitored and the frequency of monitoring have been specified in the permit, *but the parameters have not been set as enforceable limits. In order to make the parametric monitoring conditions enforceable, a correlation needs to be*

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[42] 401 KAR 52:001 contains a more general definition of start-up, "setting in operation of an affected facility." 401 KAR 52:001(231) This definition is unenforceably vague and should be supplemented by additional permit language.

[43] Likewise, Kentucky regulations define shutdown as "the cessation of an operation," which also should be supplemented by enforceable permit language.

> *developed between the control equipment parameter(s) to be monitored and the pollutant emission levels.*[44]

The Permit must explicitly state that an exceedance of an indicator is a violation of the underlying applicable requirement; otherwise, the indicator does not assure that the underlying requirement is enforceable,

b. Vague and ambiguous language.

As discussed above with respect to specific permit conditions, the Permit contains numerous words and phrases that are vague and thus unenforceable. These words and phrases include "reasonable precautions," "clean", "as applicable", "suitable", "other measures", "prompt", and "as necessary." The U.S. EPA has made clear that these terms render conditions practicably unenforceable. U.S. EPA Region 9, "Title V Permit Review Guidelines: Practical Enforceability," Sept. 9 1999, at III-55 and 61 ("It is also important that permit conditions be unambiguous and do not contain language which may intentionally or unintentionally prevent enforcement"; listing language indicating enforceability problems and instructing use of specific language). The permit must be amended to include numeric limits or specific actions with which the source must comply for conditions containing vague and ambiguous language. These conditions include, but are not limited to, Unit 07 (coal handling), Condition 1(a); Unit 08 (cooling tower), Condition 1(a); and Unit 10 (roadways), Condition 1(a).

III. THE APPLICANT FAILED TO DEMONSTRATE THAT THE FACILITY WILL NOT CAUSE OR CONTRIBUTE TO A VIOLATION OF AIR QUALITY STANDARDS

a. Emissions inventories

The applicant requested a listing of all sources located within 100 kilometers of Cash Creek to determine the emissions inventory for air quality modeling. App. p. 6-16. It is not clear from this discussion whether permitted but not yet operating facilities were included in the inventory. Further, ERORA also should have included the projected emissions of sources which have been issued PSD permits but which are not yet operating.[45] For example, ERORA should have included the maximum allowable emission rates of LG&E's Trimble County unit currently under construction, and the maximum allowable short term average emission rates must be evaluated in determining compliance with short-term average standards or increments. [ANY OTHERS?] KDAQ should confirm whether such facilities were included and if they were not, deny the permit and require the applicant to resubmit the air quality analysis with the expanded inventory.

In addition, there are clearly sources that will likely have a significant concentration gradient in the vicinity of Cash Creek that should be included in Class II increment and NAAQS modeling. These include but are not limited to the nation's largest coalplant, Duke's Gibson station (3350 MW), the TVA Paradise station in Muhlenberg County (2650 MW), the Big Rivers Coleman

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[44] U.S. EPA Region 4 Objection, Proposed Part 70 Operating Permit, Tampa Electric Company, F.J. Gannon Station, Permit No. 0570040-002-AV

[45] *see* page C.34 of the New Source Review Workshop Manual.

plant, the Southwire aluminum plant located in Hancock County, the Waupaca Foundry in Perry County, IN, and the AK Steel plant in Rockport.

Also, there are several ethanol plants and at least one biodiesel plant in the region that should have been included in the inventory but were not. There are at least two ethanol plants planned for Henderson County and a biodiesel plant proposed for Daviess County. In Indiana, there are three (at least one has secured a permit) in Posey County, one in Spencer County and one in Pike County that should be included in the analysis. ERORA also should have included emissions from oil and gas wells in the vicinity of the project. The mobile source and fugitive emissions associated with the roads for oil and gas development must also be included in the inventory of sources for a cumulative analysis.

Thus, KDAQ cannot adequately assess whether the Cash Creek source will cause or contribute to a violation of the NAAQS or Class II increments based on the analysis provided in the Cash Creek permit application. KDAQ must require ERORA to conduct a complete NAAQS and Class II increment by modeling the Patriot mine together as one source and by requiring the emissions inventory for the cumulative NAAQS and Class II increment analyses to be expanded to include all of the above sources and any other sources of air pollution, including minor and area sources, within the vicinity of the Cash Creek source.
Also, it is not clear that all required sources were included in the increment consumption modeling. Sources that consume increment are: (1) the applicant source, (2) all increases since the minor source baseline date (the date of the first complete PSD application), and (3) all significant increases at major sources after the major source baseline date (1975)-- i.e., major modifications subject to PSD/NSR-- even those that should have but did not get a permit. Typically, applicants only look at the first two. KDAQ should confirm that the source did not omit any unpermitted modifications at any nearby sources since 1975 from the increment analysis. If any modified, unpermitted sources were omitted, KDAQ should return the application to ERORA for proper increment modeling.

b. Meteorological data

The PSD Application assesses compliance with the NAAQS and PSD increments for CO and PM10 using five years of meteorological data from airports in Evansville (surface data). The airport data is not of acceptable quality for air dispersion modeling. The Cash Creek PSD Application, which relies on these data for air modeling, is therefore flawed and likely underestimates modeled concentrations due to the way calms are treated, as discussed below.

Airport data are not collected with the thought of air dispersion modeling in mind. For example, airport conditions are typically reported once per hour, based on a single observation (usually) taken in the last ten minutes of each hour. The USEPA recommends that sampling rates of 60 to 360 per hour, at a minimum, be used to calculate hourly-averaged meteorological data.[46] Air dispersion modeling requires hourly-averaged data, which represents the entire hour being modeled, and not only a snapshot taken in one moment during the hour.

In addition, data collected at the Evansville airport is not subject to the system accuracies required for meteorological data collected for air dispersion modeling. U.S. EPA recommends

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[46] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 4-2.

that meteorological monitoring for dispersion modeling use equipment that are sensitive enough to measure all conditions necessary for verifying compliance with the NAAQS and PSD increments. For example, low wind speeds (down to 1.0 meter per second) are usually associated with peak air quality impacts – this is because modeled impacts are *inversely* proportional to wind speed. Following USEPA guidance, wind speed measuring devices (anemometers) should have a starting threshold of 0.5 meter per second or less.[47] Additionally, the wind speed measurements should be accurate to within plus or minus 0.2 meter per second, with a measurement resolution of 0.1 meter per second.[48]

The airport data used by ERORA, rather than being measured in 0.1 meter per second increments, is based on wind speed observations that are reported in whole knots. Thus, any winds lower than one or two knots are reported as calms, and are thus excluded from the modeling analyses. In no uncertain terms, the conditions most crucial for verifying compliance with the NAAQS and PSD increments (low wind speeds) are being excluded from the Cash Creek analysis because of the choice to use the airport data.

Sensitive and accurate measurements of wind speeds are necessary for measuring winds down to 0.5 meter per second (about one knot), which can then be used as 1.0 meter per second in the air dispersion modeling analyses. There would be no need to label such low wind speed hours as calm, which will greatly increase the number of hours included in the modeling analyses. Again, it is these low wind speed hours which must be included in the modeling data set to verify compliance with the NAAQS or PSD increments.

KDAQ should have required ERORA to collect pre-construction meteorological data for use in the Cash Creek air quality modeling. Cash Creek, which is a major emission source of many air pollutants, should not be assessed for PSD increment compliance using meteorological data collected with none of the quality assurances necessary for air modeling data.[49]

IV. THE IGCC FACILITY AND COAL MINE SHOULD BE PERMITTED AS A SINGLE FACILITY

The SOB states that "the primary coal supply is expected be provided by the Patriot Coal Company, which operates an existing underground and surface mining and processing operation adjacent to the Cash Creek location. The coal will be delivered by a conveyor from the mine to an onsite receiving transfer-house." SOB at p.1. KDAQ issued the Patriot coal processing facility a construction and operating permit, Permit No. S-06-333, on December 6, 2006. Due to the interdependence of the two facilities and the increased production at Patriot necessitated by Cash Creek[50], the facilities must be evaluated as one entire source for the purposes of the PSD permit for Cash Creek. This means that in evaluating whether the Cash Creek source's impacts will be

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[47] Id., p. 5-2.

[48] Id., p. 5-1.

[49] USEPA, Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-07, May 1987, p. 55.

[50] According to an IEPA press release for the analogous ERORA Taylorville facility, the plant will consume approximately 1.8 million tons of Illinois coal per year. Patriot's three Western Kentucky mines together produced only 4 million tons of coal in 2004. See Peabody Energy Press Release, Nov. 9, 2005, "Patriot Coal Company Earns Reclamation Honors From the Kentucky Department of Natural Resources & Kentucky Coal Association," available at http://phx.corporate-ir.net/phoenix.zhtml?c=129849&p=irol-newsArticle&ID=780974&highlight=. Thus, the Cash Creek facility will require the Patriot mine to potentially more than double its production level, which will in turn significantly impact air emissions.

over the regulatory ambient significance levels, both facilities must be modeled together. Further, in determining the Cash Creek source's impact area for each pollutant and the impacts on visibility and other air quality related values of Class I areas, the two facilities must be modeled simultaneously to predict the overall impacts from the Cash Creek source.

Any attempt to model only impacts from the Cash Creek nominal 770 MW facility must be considered circumvention of the PSD permitting regulations and must not be allowed by KDAQ.

V. PUBLIC PARTICIPATION

On Wednesday, June 6, 2007, both Meleah Geertsma and John Blair sent requests to John Lyons for an extension of the written comment period. In her request, Ms. Geertsma noted the challenges to finding a technical expert on IGCC within the standard time period, based on the relative newness of the technology. Both requests were denied outright, with the caveat that written comments could be submitted through a representative at the public hearing to be held ten days after the close of the written comment period due to a scheduling problem within KDAQ. Ms. Geertsma again requested an extension on June 19, quoting from Hearing Officer Dickinson's report in the Trimble case, issued earlier that week, noting systemic problems with the Division's treatment of public participation requirements. This report echoed the critiques stated by Hearing Officer Janet Raider in her April report on the Spurlock permit. Mr. Lyons again rejected the request. In neither of Mr. Lyons' response did he provide any justification for denying the requests beyond the extra days afforded by the Division's scheduling problems. In fact, Mr. Lyons implied that he did not have the authority to extend the comment period under Kentucky regulations ("401 KAR 52:100, Sections 2(2)(a) & 2(2)(b), are very prescriptive in that the comment period "shall" begin on the date the notice is published and "shall" end thirty (30) days after the publication date.")

The blank rejection of these justified requests is unacceptable and evidences the Division's inexplicable and on-going resistance to the public's input on its permits. The public comment period exists so that the public can express its concerns with a permit to the agency, outside of the adversarial, expensive process of an administrative hearing. It is the opportunity for an exchange, with the end goal of meeting the air quality laws and regulations to the greatest extent possible. Blank refusals to extend the comment period, particularly in light of the numerous and repeated shortcomings in the process itself noted by Hearing Officers Dickinson and Raider which produce delay and confusion for the public, prevent the public from having a meaningful opportunity to comment as the law requires. Nor does Kentucky law prescribe a maximum 30-day comment period as suggested by Mr. Lyons. The above quote conveniently leaves out the language in 401 KAR 52:100, Section 2(1)(a) clearly stating that the Cabinet shall afford a "*minimum* of thirty (30) days for public comment."

Commenters note that, due to the short time period for reviewing this voluminous and complex permit record, we have focused our comments on the BACT limits and not included complete comments on several areas which we believe to be deficient. These areas include the enforceability of numerous permit conditions, as well as the applicant's air quality modeling demonstration and soils and vegetation assessment. It should also be noted that the volume of these comments is in large part due to the extensive work of other advocates to generate the general arguments on carbon dioxide in other cases. The allotted time was wholly insufficient to do the permit-specific review necessary to meaningfully comment on the materials available for public review. Nor was the by-chance additional time to submit written comments at the hearing sufficient. We are aware of others who needed additional time to submit written comments and who had to scramble to find persons to hand deliver the comments and represent these comments at the hearing.

In sum, we are commenting on the insufficient opportunity afforded by the Division with regards to the draft permit. To correct these errors, the Division should seriously consider reopening the comment period. In addition, in the event that comments from this period result in significant changes to the permit limits, the Division should notice an additional comment period on the revised draft permit prior to finalizing it. We finally strongly urge the Division to follow, at a minimum, the recommendations laid out in the referenced Hearing Officer's reports. Ample room exists *now* under the Division's regulations for improving the opportunity for public participation in the ways noted. The Division's regulations also could be improved by amendments clearly laying out the standards for extensions. Finally, we note appreciation for the provision of electronic files during this comment period and recommend that such files be assembled prior to the notice date to enable the timely review of the voluminous files.

VI. CONCLUSION

For the reasons stated above, KDAQ should deny the Cash Creek-ERORA draft permit as a matter of law and fully comply with the duty to provide a meaningful opportunity for public participation during the remainder of the permit's consideration. If you have any questions about these comments or require additional information, please do not hesitate to contact Meleah Geertsma at 312-795-3713.

Thank you for your consideration of this important matter

Sincerely,

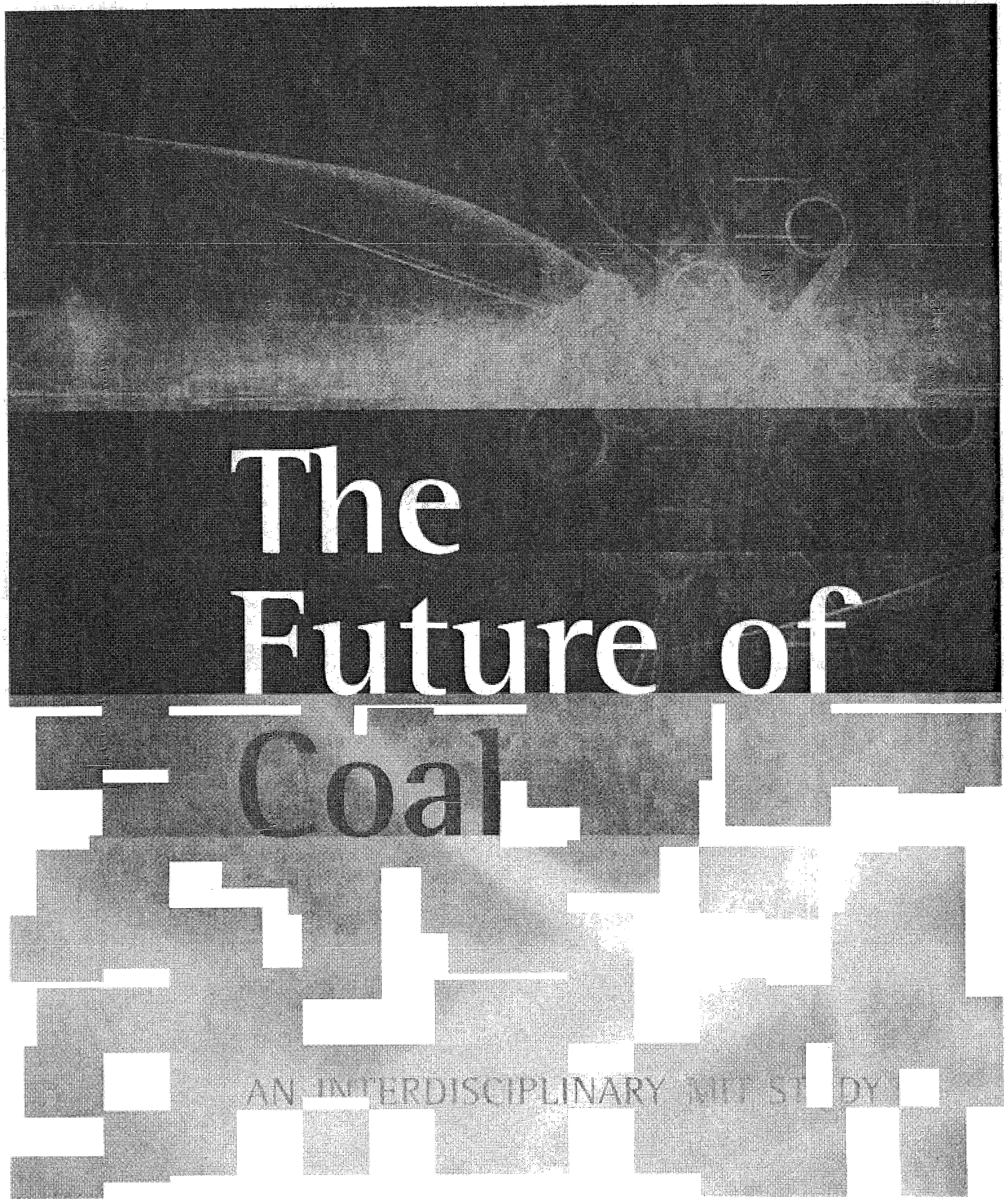
Meleah A. Geertsma
Staff Attorney and Public Health Specialist
Environmental Law and Policy Center
Chicago, IL

Bruce Nilles
Senior Midwest Representative
Sierra Club

John Blair
Executive Director
Valley Watch, Inc.

Attachment 1

Comments of
Environmental Law & Policy Center, Sierra Club and Valley Watch Inc.



The Future of Coal

AN INTERDISCIPLINARY MIT STUDY

Chapter 3 — Coal-Based Electricity Generation

INTRODUCTION

In the U.S., coal-based power generation is expanding again; in China, it is expanding very rapidly; and in India, it appears on the verge of rapid expansion. In all these countries and worldwide, the primary generating technology is pulverized coal (PC) combustion. PC combustion technology continues to undergo technological improvements that increase efficiency and reduce emissions. However, technologies favored for today's conditions may not be optimum under future conditions. In particular, carbon dioxide capture and sequestration in coal-based power generation is an important emerging option for managing carbon dioxide emissions while meeting growing electricity demand, but this would add further complexity to the choice of generating technology.

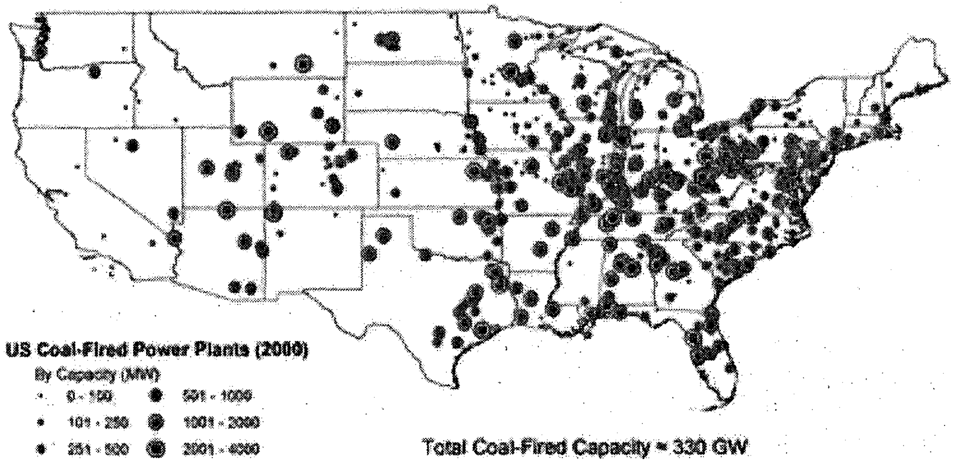
The distribution of coal-based generating plants for the U. S. is shown in Figure 3.1. Most of the coal-based generating units in the U. S. are between 20 and 55 years old; the average age of the fleet is over 35 years[1]. Coal-based generating units less than 35 years old average about 550 MW_e; older generating units are typically smaller. With current life-extension capabilities, many of these units could, on-average, operate another 30+ years. Units that are less than about 50 years old are essentially all air-blown, PC combustion units. The U.S. coal fleet average generating efficiency is about 33%, although a few, newer generating units exceed 36% efficiency [2][3]. Increased generating efficiency is important, since it translates directly into lower criteria pollutant emissions (at a given removal efficiency) and lower carbon dioxide emissions per kW_e-h of electricity generated.

GENERATING TECHNOLOGIES — OVERVIEW

This chapter evaluates the technologies that are either currently commercial or will be commercially viable in the near term for electricity generation from coal. It focuses primarily on the U. S., although the analysis is more broadly applicable. We analyze these generating technologies in terms of the cost of electricity produced by each, without and with carbon dioxide (CO_2) capture, and their applicability, efficiency, availability and reliability. Power generation from coal is subject to a large number of variables which impact technology choice, operating efficiency, and cost of electricity (COE) produced [4]. Our approach here was to pick a point set of conditions at which to compare each of the generating technologies, using a given generating unit design model to provide consistency. We then consider how changes from this point set of conditions, such as changing coal type, impact the design, operation, and cost of electricity (COE) for each technology. We also consider emissions control and retrofits for CO_2 capture for each technology. Appendix 3.A summarizes coal type and quality issues, and their impact.

For the technology comparisons in this chapter, each of the generating units considered was a green-field unit which contained all the emissions control equipment required to operate slightly below current, low, best-demonstrated criteria emissions performance levels.

Figure 3.1 Distribution of U. S. Coal-Based Power Plants. Data from 2002 USEPA eGRID database; Size Of Circles Indicate Power Plant Capacity.



To evaluate the technologies on a consistent basis, the design performance and operating parameters for these generating technologies were based on the Carnegie Mellon Integrated Environmental Control Model, version 5.0 (IECM) [5] which is a modeling tool specific to coal-based power generation [6] [7]. The units all use a standard Illinois # 6 bituminous coal, a high-sulfur, Eastern U.S. coal with a moderately high heating value (3.25 wt% sulfur & 25,350 kJ/kg (HHV)). Detailed analysis is given in Table A-3.B.1 [5] (Appendix 3.B).

GENERATING EFFICIENCY The fraction of the thermal energy in the fuel that ends up in the net electricity produced is the generating efficiency of the unit [8]. Typical modern coal units range in thermal efficiency from 33% to 43% (HHV). Generating efficiency depends on a number of unit design and operating parameters, including coal type, steam temperature and pressure, and condenser cooling water temperature [9]. For example, a unit in Florida will generally have a lower operating efficiency than a unit in northern New England or in northern Europe due to the higher cooling water temperature in Florida. The difference in generating efficiency could be 2 to 3 percentage points. Typically, units operated at near capacity exhibit their highest efficiency; unit cycling and operating below capacity result in lower efficiency.

LEVELIZED COST OF ELECTRICITY

The levelized cost of electricity (COE) is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors. Levelized COE is comprised of three components: capital charge, operation and maintenance costs, and fuel costs. Capital cost is generally the largest component of COE. This study calculated the capital cost component of COE by applying a carrying charge factor of 15.1% to the total plant cost (TPC). Appendix 3.C provides the basis for the economics discussed in this chapter.

AIR-BLOWN COAL COMBUSTION GENERATING TECHNOLOGIES

In the next section we consider the four primary air-blown coal generating technologies that compose essentially all the coal-based power generation units in operation today and being built. These include PC combustion using subcritical, supercritical, or ultra-supercritical steam cycles designed for Illinois #6 coal and circulating fluid-bed (CFB) combustion designed for lignite. Table 3.1 summariz-

Table 3.1 Representative Performance And Economics For Air-Blown PC Generating Technologies

	SUBCRITICAL PC		SUPERCRITICAL PC		ULTRA-SUPERCRITICAL PC		SUBCRITICAL CFB[6]	
	W/O CAPTURE	W/ CAPTURE	W/O CAPTURE	W/ CAPTURE	W/O CAPTURE	W/ CAPTURE	W/O CAPTURE	W/ CAPTURE
PERFORMANCE								
Heat rate (1), Btu/kW_e-h	9,950	13,600	8,870	11,700	7,880	10,000	9,810	13,400
Generating efficiency (HHV)	34.3%	25.1%	38.5%	29.3%	43.3%	34.1%	34.8%	25.5%
Coal feed, kg/h	208,000	284,000	185,000	243,000	164,000	209,000	297,000	406,000
CO_2 emitted, kg/h	466,000	63,600	415,000	54,500	369,000	46,800	517,000	70,700
CO_2 captured at 90%, kg/h (2)	0	573,000	0	491,000	0	422,000	0	36,000
CO_2 emitted, g/kW_e-h	931	127	830	109	738	94	1030	141
COSTS								
Total Plant Cost, \$/kW_e (3)	1,280	2,230	1,330	2,140	1,360	2,090	1,330	2,270
Inv.Charge, ¢/kW_e-h @ 15.1% (4)	2.60	4.52	2.70	4.34	2.76	4.24	2.70	4.60
Fuel, ¢/kW_e-h @ \$1.50/MMBtu	1.49	2.04	1.33	1.75	1.18	1.50	0.98	1.34
O&M, ¢/kW_e-h	0.75	1.60	0.75	1.60	0.75	1.60	1.00	1.85
COE, ¢/kW_e-h	**4.84**	**8.16**	**4.78**	**7.69**	**4.69**	**7.34**	**4.68**	**7.79**
Cost of CO_2 avoided[5] vs. same technology w/o capture, \$/tonne	41.3		40.4		41.1		39.7	
Cost of CO_2 avoided[5] vs. supercritical w/o capture, \$/tonne	48.2		40.4		34.8		42.8	

Basis: 500 MW_e net output. Illinois # 6 coal (61.2% wt C, HHV = 25,350 kJ/kg), 85% capacity factor

(1) efficiency = 3414 Btu/kW_e-h/(heat rate);

(2) 90% removal used for all capture cases

(3) Based on design studies and estimates done between 2000 & 2004, a period of cost stability, updated to 2005\$ using CPI inflation rate. 2007 cost would be higher because of recent rapid increases in engineering and construction costs, up 25 to 30% since 2004.

(4) Annual carrying charge of 15.1% from EPRI-TAG methodology for a U.S. utility investing in U.S. capital markets; based on 55% debt @ 6.5%, 45% equity @ 11.5%, 38% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge

(5) Does not include costs associated with transportation and injection/storage

(6) CFB burning lignite with HHV = 17,400 kJ/kg and costing \$1.00/million Btu

es representative operating performance and economics for these air-blown coal combustion generating technologies. Appendix 3.C provides the basis for the economics. PC combustion or PC generation will be used to mean air-blown pulverized coal combustion for the rest of this report, unless explicitly stated to be oxy-fuel PC combustion for oxygen-blown PC combustion.

PULVERIZED COAL COMBUSTION POWER GENERATION: WITHOUT CO_2 CAPTURE

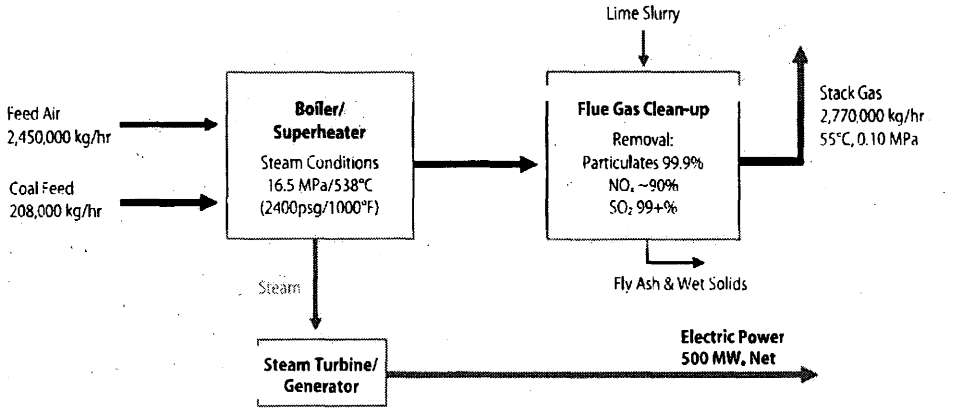
SUBCRITICAL OPERATION In a pulverized coal unit, the coal is ground to talcum-powder fineness, and injected through burners into the furnace with combustion air [10-12]. The fine coal particles heat up rapidly, undergo pyrolysis and ignite. The bulk of the combustion air is then mixed into the flame to completely burn the coal char. The flue gas from the boiler passes through the flue gas clean-up units to remove particulates, SO_x, and NO_x. The flue gas exiting the clean-up section meets criteria pollutant permit requirements, typically contains 10–15% CO_2 and is essentially at atmospheric pressure. A block diagram of a subcritical PC generating unit is shown in Figure 3.2. Dry, saturated steam is generated in the furnace boiler tubes and is heated further in the superheater section of the furnace. This high-pressure, superheated steam drives the steam turbine coupled to an electric generator. The low-pressure steam exiting the steam turbine is condensed, and the condensate pumped back to the boiler for conversion into steam. Subcritical operation refers to steam pressure and temperature below 22.0 MPa (~3200 psi) and about 550° C (1025° F) respectively. Subcritical PC units have generating efficiencies between 33 to 37% (HHV), dependent on coal quality, operations and design parameters, and location.

Key material flows and conditions for a 500 MW_e subcritical PC unit are given in Figure 3.2 [5, 13]. The unit burns 208,000 kg/h (208 tonnes/h [14]) of coal and requires about 2.5 million kg/h of combustion air. Emissions control was designed for 99.9% PM and 99+% SO_x reductions and greater than about 90% NO_x reduction. Typical subcritical steam cycle conditions are 16.5 MPa (~2400 psi) and 540° C (1000° F) superheated steam. Under these operating conditions (Figure 3.2), IECM projects an efficiency of 34.3% (HHV) [15]. More detailed material flows and operating conditions are given in Appendix 3.B, Figure A-3.B.2, and Table 3.1 summarizes the CO_2 emissions.

The coal mineral matter produces about 22,800 kg/h (23 tonnes/h) of fly and bottom ash. This can be used in cement and/or brick manufacture. Desulfurization of the flue gas produces about 41,000 kg/h (41 tonnes/h) of wet solids that may be used in wallboard manufacture or disposed of in an environmentally safe way.

SUPERCRITICAL AND ULTRA-SUPERCRITICAL OPERATION Generating efficiency is increased by designing the unit for operation at higher steam temperature and pressure. This represents a movement from subcritical to supercritical to ultra-supercritical steam parameters [16]. Supercritical steam cycles were not commercialized until the late 1960s, after the necessary materials technologies had been developed. A number of supercritical units were built in the U.S. through the 1970's and early 80's, but they were at the limit of the then-available materials and fabrication capabilities, and some problems were encountered [17]. These problems have been overcome for supercritical operating conditions, and supercritical units are now highly reliable. Under supercritical conditions, the supercritical fluid is expanded through the high-pressure stages of a steam turbine, generating electricity. To recharge the steam properties and increase the amount of power generated, after expansion through the high-pressure turbine stages, the

Figure 3.2 Subcritical 500 MW_e Pulverized Coal Unit without CO_2 Capture



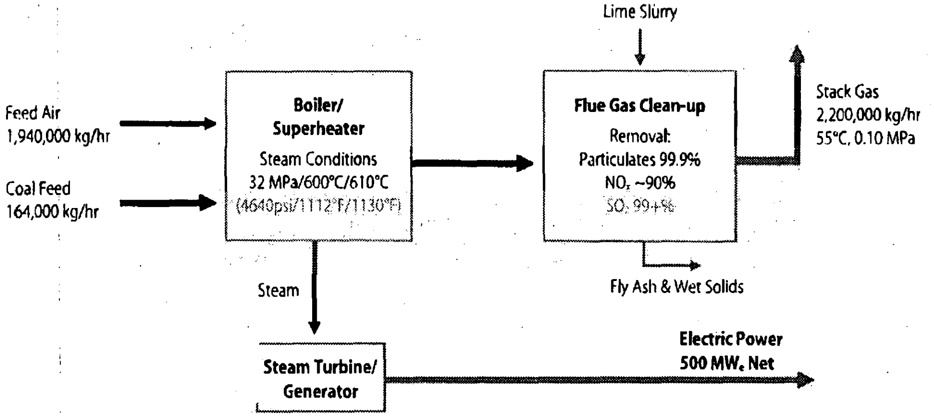


Figure 3.3 Ultra-Supercritical 500 MW_e Pulverized Coal Unit without CO_2 Capture

steam is sent back to the boiler to be reheated. Reheat, single or double, increases the cycle efficiency by raising the mean temperature of heat addition to the cycle.

Supercritical electricity generating efficiencies range from 37 to 40% (HHV), depending on design, operating parameters, and coal type. Current state-of-the-art supercritical PC generation involves 24.3 MPa (~3530 psi) and 565° C (1050° F), resulting in a generating efficiency of about 38% (HHV) for Illinois #6 coal.

Meanwhile, new materials capabilities have been further expanding the potential operating range. To take advantage of these developments, the power industry, particularly in Europe and Japan, continues to move to higher steam pressure and temperature, primarily higher temperatures. Operating steam cycle conditions above 565° C (>1050° F) are referred to as ultra-supercritical. A number of ultra-supercritical units operating at pressures to 32 MPa (~4640 psi) and temperatures to 600/610° C (1112-1130° F) have been constructed in Europe and Japan [18]. Operational availability of these units to date has been comparable to that of subcritical plants. Current materials research and development is targeting steam cycle operating conditions of 36.5 to 38.5 MPa (~5300-5600 psi) and temperatures of 700-720° C (1290-1330° F)[19]. These conditions should increase generating efficiency to the 44 to 46% (HHV) range for bituminous coal, but require further materials advances, particularly for manufacturing, field construction, and repair.

Figure 3.3 is a block diagram of a 500 MW_e ultra-supercritical PC generating unit showing key flows. The coal/combustion side of the boiler and the flue gas treatment are the same as for a subcritical boiler. Coal required to generate a given amount of electricity is about 21% lower than for subcritical generation, which means that CO_2 emissions per MW_e-h are reduced by 21%. The efficiency projected for these design operating conditions is 43.3% (HHV) (Figure 3.3) vs. 34.3% for subcritical conditions. More detailed material and operating information is given in Appendix 3.B. Table 3.1 summarizes the performance for subcritical, supercritical, and ultra-supercritical operation.

FLUID-BED COMBUSTION A variation on PC combustion is fluid-bed combustion in which coal is burned with air in a fluid bed, typically a circulating fluid bed (CFB)[20-22]. CFBs are best suited to low-cost waste fuels and low-quality or low heating value coals. Crushed coal and limestone are fed into the bed, where the limestone undergoes calcination to produce lime (CaO). The fluid bed consists mainly of lime, with a few percent coal, and recirculated coal char. The bed operates at significantly lower temperatures, about 427° C (800° F), which thermodynamically favors low NO_x formation and SO_2 capture by reaction with CaO to form $CaSO_4$. The steam cycle can be subcritical and potentially supercritical, as with PC combustion, and generating efficiencies are similar. The primary advantage of CFB technology is its capability to capture SO_2 in the bed, and its flexibility to a wide range of coal properties, including coals with low heating value, high-ash coals and low-volatile coals, and to changes in coal type during operation. Several new lignite-burning CFB units have been constructed recently, and CFBs are well suited to co-firing biomass [23].

The performance data for the CFB unit in Table 3.1 is based on lignite rather than Illinois # 6 coal. The lignite has a heating value of 17,400 kJ/kg and low sulfur. The coal feed rate is higher than for the other technologies because of the lower heating value of the lignite. Appendix 3.B gives a detailed process schematic for CFB generation.

COAL TYPE AND QUALITY EFFECTS

Coal type and quality impact generating unit technology choice and design, generating efficiency, capital cost, performance, and COE (Appendix 3.A). Boiler designs today usually encompass a broader range of typical coals than initially intended to provide future flexibility. Single coal designs are mostly limited to mine-mouth plants, which today are usually only lignite, subbituminous, or brown coal plants. The energy, carbon, moisture, ash, and sulfur contents, as well as ash characteristics, all play an important role in the value and selection of coal, in its transportation cost, and in the technology choice for power generation. For illustration, Table 3.2 gives typical values and ranges for various coal properties as a function of coal type. Although most of the studies available are based on bituminous coals, a large fraction of the power generated in the U.S. involves Western subbituminous coals (>35%), such as Powder River Basin, because of its low sulfur content.

Each of these coal properties interacts in a significant way with generation technology to affect performance. For example, higher sulfur content reduces PC generating efficiency due to the added energy consumption and operating costs to remove SO_x from the flue gas. High ash content requires PC design changes to manage erosion. High ash is a particular problem with Indian coals. Fluid-bed combustion is well suited to high-ash coals, low-carbon coal waste, and lignite. Several high-efficiency, ultra-supercritical and supercritical PC generating units have recently been commissioned in Germany burning brown coal or lignite, and several new CFB units have been constructed in Eastern Europe, the U.S., Turkey and India burning lignite and in Ireland burning peat[23, 24].

Coal types with lower energy content and higher moisture content significantly affect capital cost and generating efficiency. About 50% of U.S. coal is sub-bituminous or lignite. Using bituminous Pittsburgh #8 as the reference, PC units designed for Powder River Basin (PRB) coal and for Texas lignite have an estimated 14% and 24% higher capital cost respectively. Generating efficiency decreases but by a smaller percentage (Appendix 3.A, Figure A-3.A.3) [25]. However, the lower cost of coal types with lower heating value can offset the impact of this increased capital cost and decreased efficiency, thus, resulting in very little impact on COE. Using average 2004 mine-mouth coal prices and PC generation, the COE for Illinois #6, PRB, and Texas lignite is equal to or less than that for Pittsburgh #8 (Appendix 3.A, Figure A-3.A.4).

U.S. CRITERIA POLLUTANT IMPACTS

Although coal-based power generation has a negative environmental image, advanced PC plants have very low emissions; and PC emissions control technology continues to improve and will improve further (Appendix 3.D). It is not clear when and where the ultimate limits of flue gas control will be reached. In the U.S., particulate removal, via electrostatic precipita-

Table 3.2 Typical Properties of Characteristic Coal Types

COAL TYPE	ENERGY CONTENT, kJ/kg [CARBON CONTENT, wt %]	MOISTURE, wt %	SULFUR, wt %	ASH, wt %
Bituminous*	27,900 (ave.consumed in U.S.) [67 %]	3 - 13	2 – 4	7 - 14
Sub-bituminous* (Powder River Basin)	20,000 (ave.consumed in U.S.) [49 %]	28 - 30	0.3 - 0.5	5 - 6
Lignite*	15,000 (ave.consumed in U.S.) [40 %]	30 - 34	0.6 - 1.6	7 - 16
Average Chinese Coal	19,000 - 25,000 [48 - 61 %]	3 - 23	0.4 - 3.7	28 - 33
Average Indian Coal	13,000 – 21,000 [30 - 50 %]	4 - 15	0.2 – 0.7	30 - 50

** U.S coal reserves are ~ 48 % anthracite & bituminous, ~ 37 % subbituminous, and ~ 15 % lignite (See Appendix 3-A, Figure A.2 for more details.)*

tors (ESP) or fabric filters, is universally practiced with very high levels of removal (99.9%). Flue gas desulfurization has been added to less than one-third of U.S. coal-based generating capacity [2], and post-combustion NO_x control is practiced on about 10% of the coal-based generating capacity.

The Clean Air Act (1990) set up a cap and trade system for SO_x [26] and established emissions reductions guidelines for NO_x. This has helped produce a 38% reduction in total SO_x emissions over the last 30 years, while coal-based power generation grew by 90%. Total NO_x emissions have been reduced by 25% over this period. Recent regulations, including NAAQS[27], the Clean Air Interstate Rule (CAIR) [28], and the Clean Air Mercury Rule (CAMR) [29] will require an additional 60% reduction in total SO_x emissions and an additional 45% reduction in total NO_x emissions nationally by 2020. During this period, coal-based generation is projected to grow about 35%. Mercury reduction initially comes with SO_x abatement; additional, mandated reductions come after 2009. NAAQS have produced a situation in which permitting a new coal generating unit requires extremely low emissions of particulate matter (PM), SO_x, and NO_x, driven by the need to meet stringent, local air quality requirements, essentially independent of national emissions caps.

Newly permitted coal-fired PC units routinely achieve greater than 99.5% particulate control, and removal efficiencies greater than 99.9% are achievable at little additional cost. Wet flue-gas desulfurization (FGD) can achieve 95% SO_x removal without additives and 99% SO_x removal with additives [30]. Selective catalytic reduction (SCR), combined with low-NO_x combustion technology, routinely achieves 90+% NO_x reduction over non-controlled emissions levels. New, advanced PC units in the U.S. are currently achieving criteria pollutant emissions reductions consistent with the performance outlined above and have emissions levels that are at or below the emissions levels achieved by the best PC units in Japan and Europe (Appendix 3.D).

Today, about 25% of the mercury in the coal burned is removed by the existing flue gas treatment technologies in place, primarily with the fly ash via electrostatic precipitators (ESP) or fabric filters. Wet FGD achieves 40-60% mercury removal; and when it is combined with SCR, mercury removal could approach 95% for bituminous coals [31]. For subbituminous coals, mercury removal is typically less than 40%, and may be significantly less for lignite, even when the flue gas clean-up technologies outlined above are in use. However, with activated carbon or brominated activated carbon injection removal rates can be increased to ~90% [31]. Optimization of existing technologies and new technology innovations can be expected to achieve > 90% mercury removal on most if not all coals within the next 10-15 years.

Table 3.3 gives the estimated incremental impact on the COE of the flue gas treatment technologies to meet the low emissions levels that are the design basis of this study, vs. a PC unit without controls. The impact of achieving these levels of control is about 1.0 ¢/kW_e-h

Table 3.3 Estimated Incremental Costs for a Pulverized Coal Unit to Meet Today's Best Demonstrated Criteria Emissions Control Performance Vs. No Control

	CAPITAL COST[a] [$/kW$_e$]	O&M[b] [¢/kW$_e$-h]	COE[c] [¢/kW$_e$-h]
PM Control[d]	40	0.18	0.26
NO_x	25 (50 – 90)[e]	0.10 (0.05 – 0.15)	0.15 (0.15 – 0.33)
SO_2	150 (100 – 200)[e]	0.22 (0.20 – 0.25)	0.52 (0.40 – 0.65)
Incremental control cost	215	0.50	0.93[f]

a. Incremental capital costs for a typical, new-build plant to meet today's low emissions levels. Costs for low heating value coals will be somewhat higher

b. O&M costs are for typical plant meeting today's low emissions levels. Costs will be somewhat higher for high-sulfur and low heating value coals.

c. Incremental COE impact, bituminous coal

d. Particulate control by ESP or fabric filter included in the base unit costs

e. Range is for retrofits and depends on coal type, properties, control level and local factors

f. When added to the "no-control" COE for SC PC, the total COE is 4.78 ¢/kW$_e$-h

or about 20% of the total COE from a highly-controlled PC unit. Although mercury control is not explicitly addressed here, removal should be in the 60-80% range for bituminous coals, including Illinois #6 coal, and less for subbituminous coals and lignite. We estimate that the incremental costs to meet CAIR and CAMR requirements and for decreasing the PM, SO_x, and NO_x emissions levels by a factor of 2 from the current best demonstrated emissions performance levels used for Table 3.3 would increase the cost of electricity by about an additional 0.22 ¢/kW$_e$-h (Appendix 3.D, Table A-3D.4). The total cost of emissions control is still less than 25% of the cost of the electricity produced. Meeting the Federal 2015 emissions levels is not a question of control technology capabilities but of uniform application of current technology. Meeting local emissions requirements may be a different matter.

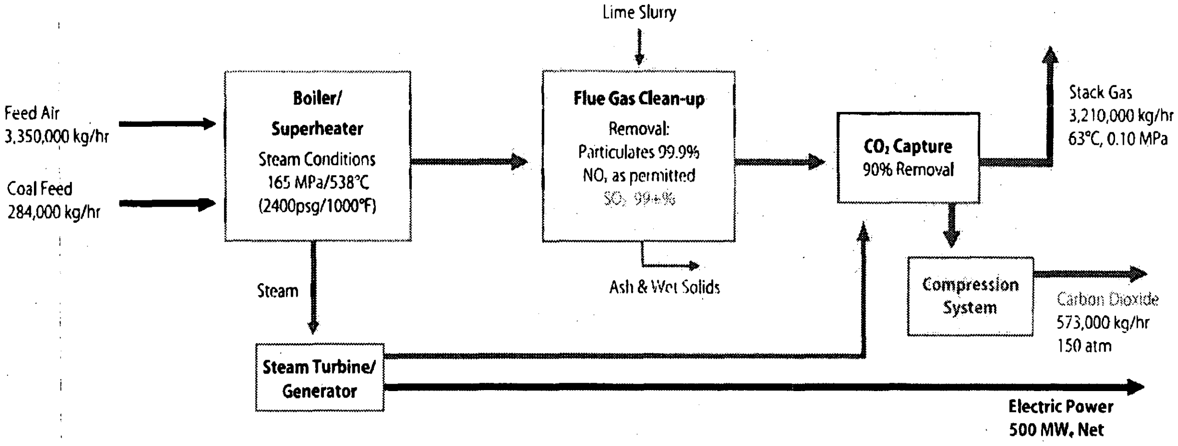
PULVERIZED COAL COMBUSTION GENERATING TECHNOLOGY: WITH CO_2 CAPTURE

CO_2 capture with PC combustion generation involves CO_2 separation and recovery from the flue gas, at low concentration and low partial pressure. Of the possible approaches to separation [32], chemical absorption with amines, such as monoethanolamine (MEA) or hindered amines, is the commercial process of choice [33, 34]. Chemical absorption offers high capture efficiency and selectivity for air-blown units and can be used with sub-, super-, and ultra-supercritical generation as illustrated in Figure 3.4 for a subcritical PC unit. The CO_2 is first captured from the flue gas stream by absorption into an amine solution in an absorption tower. The absorbed CO_2 must then be stripped from the amine solution via a temperature increase, regenerating the solution for recycle to the absorption tower. The recovered CO_2 is cooled, dried, and compressed to a supercritical fluid. It is then ready to be piped to storage.

CO_2 removal from flue gas requires energy, primarily in the form of low-pressure steam for the regeneration of the amine solution. This reduces steam to the turbine and the net power output of the generating plant. Thus, to maintain constant net power generation the coal input must be increased, as well as the size of the boiler, the steam turbine/generator, and the equipment for flue gas clean-up, etc. Absorption solutions that have high CO_2 binding energy are required by the low concentration of CO_2 in the flue gas, and the energy requirements for regeneration are high.

A subcritical PC unit with CO_2 capture (Figure 3.4), that produces 500 MW$_e$ net power, requires a 37% increase in plant size and in coal feed rate (76,000 kg/h more coal) vs. a

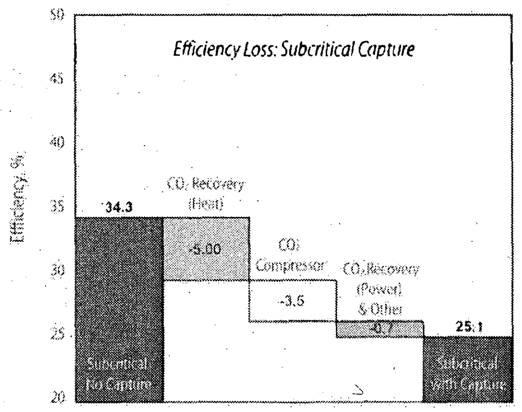
Figure 3.4 Subcritical 500 MW_e Pulverized Coal Unit with CO_2 Capture



500 MW_e unit without CO_2 capture (Figure 3.2). The generating efficiency is reduced from 34.3% to 25.1% (Table 3.1). The primary factors in efficiency reduction associated with addition of CO_2 capture are illustrated in Figure 3.5. The thermal energy required to recover CO_2 from the amine solution reduces the efficiency by 5 percentage points. The energy required to compress the CO_2 from 0.1 MPa to about 15 MPa (to a supercritical fluid) is the next largest factor, reducing the efficiency by 3.5 percentage points. All other energy requirements amount to less than one percentage point.

An ultra-supercritical PC unit with CO_2 capture (Figure 3.6) that produces the same net power output as an ultra-supercritical PC unit without CO_2 capture (Figure 3.3) requires a 27% increase in unit size and in coal feed rate (44,000 kg/h more coal). Figure 3.7 illustrates the main factors in efficiency reduction associated with addition of CO_2 capture to an ultra-supercritical PC unit. The overall efficiency reduction is 9.2 percentage points in both cases, but the ultra-supercritical, non-capture unit starts at a sufficiently high efficiency that with CO_2 capture, its efficiency is essentially the same as that of the subcritical unit without CO_2 capture.

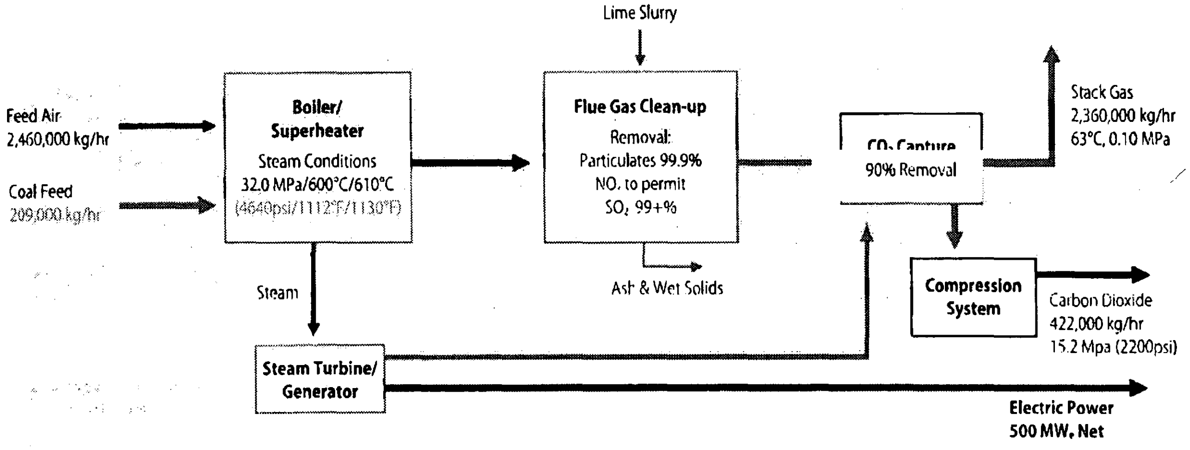
Figure 3.5 Parasitic Energy Requirements for a Subcritical Pulverized Coal Unit With Post-Combustion CO_2 Capture



COST OF ELECTRICITY FOR AIR-BLOWN PULVERIZED COAL COMBUSTION

The cost of electricity (COE), without and with CO_2 capture, was developed for the competing technologies analyzed in this report through a detailed evaluation of recent design studies, combined with expert validation. Appendix 3.C lists the studies that formed the basis for our report (Table A-3.C.2), provides more detail on each, and details the approach used. The largest and most variable component of COE among the studies is the capital charge, which is dependent on the total plant (or unit) cost (TPC) and the cost of capital. Figure 3.8 shows

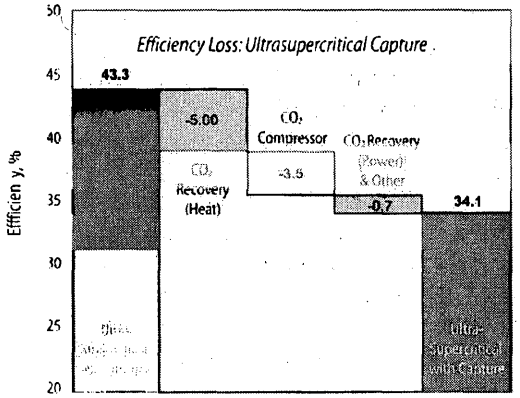
Figure 3.6 Ultra-Supercritical 500 MW$_e$ Pulverized Coal Unit with CO_2 Capture



the min, max, and mean of the estimated TPC for each technology expressed in 2005 dollars. Costs are for a 500 MW$_e$ plant and are given in \$/kW$_e$ net generating capacity.

In addition to the variation in TPC, each of these studies used different economic and operating parameter assumptions resulting in a range in the capital carrying cost, in the O&M cost, and in the fuel cost. The differences in these assumptions among the studies account for much of the variability in the reported COE. The COE from these studies is shown in Figure 3.9, where the "as-reported" bars show the min, max, and mean in the COE for the different technologies as reported in the studies in the dollars of the study year. Appendix 3.C provides more detail.

Figure 3.7 Parasitic Energy Requirements for an Ultra-Supercritical Pulverized Coal Unit with Post-Combustion CO_2 Capture



To compare the studies on a more consistent basis, we recalculated the COE for each of the studies using the normalized economic and operating parameters listed in Table 3.4. O&M costs are generally considered to be technology and report-specific and were not changed in this analysis. Other factors that contribute to variation include regional material and labor costs, and coal quality impacts. The "normalized" bars in Figure 3.9 summarize the results of this analysis of these design studies.

The variation in "as-reported" COE for non-capture PC combustion is small because of the broad experience base for this technology. Significant variation in COE exists for the CO_2 capture cases due to the lack of commercial data. The normalized COE values are higher for most of the cases because we used a higher fuel price and put all cost components in 2005 dollars.

To develop the COE values for this report, we took the TPC numbers from the design studies (Figure 3.8), adjusted them to achieve internal consistency (e.g. SubC PC<SC PC<USC PC), then compared our TPC numbers with industry consensus group numbers [35] and made secondary adjustments based on ratios and deltas from these numbers. This produced the TPC values in Table 3.1. Using these TPC

numbers, the parameters in Table 3.4, and estimated O&M costs, we calculated the COE for each technology, and these are given in Table 3.1.

Total plant costs shown above and in Table 3.1 were developed during a period of price stability [2000-2004] and were incremented by CPI inflation to 2005$. These costs and the deltas among them were well vetted, broadly accepted, and remain valid in comparing costs of different generating technologies. However, significant cost inflation from 2004 levels due to increases in engineering and construction costs including labor, steel, concrete and other consumables used for power plant construction, has been between 25 and 30%. Thus, a SCPC unit with an estimated capital cost of $1330 (Table 3.1) is now projected at $1660 to $1730/ kW$_e$ in 2007$. Because we have no firm data on how these cost increases will affect the cost of the other technologies evaluated in this report, the discussion that follows is based on the cost numbers in Table 3.1, which for relative comparison purposes remain valid.

For PC generation without CO_2 capture, the COE decreases from 4.84 to 4.69 ¢/kW$_e$-h from subcritical to ultra-supercritical technology because efficiency gains outweigh the additional capital cost (fuel cost component decreases faster than the capital cost component increases). Historically, coal cost in the U.S. has been low enough that the economic choice has been subcritical PC. The higher coal costs in Europe and Japan have driven the choice of higher-efficiency generating technologies, supercritical and more recently ultra-supercritical. For the CFB case, the COE is similar to that for the PC cases, but this is because cheaper lignite is the feed, and emissions control is less costly. The CFB design used here does not achieve the very low criteria emissions achieved by our PC design. For Illinois #6 and comparable emissions limits, the COE for the CFB would be significantly higher.

Figure 3.8 Total Plant Cost for Air-Blown Coal Combustion Power Generation Technologies from Recent Design Studies. The Min, Max, and Mean (2005 Dollars) Are Shown When Multiple Studies Evaluated a Given Technology.

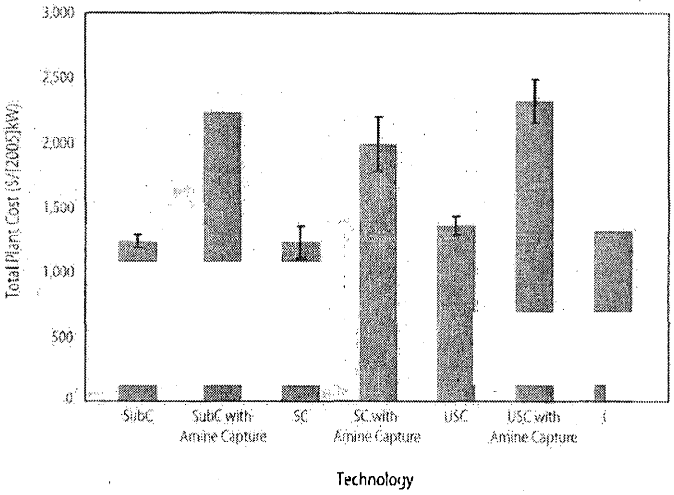


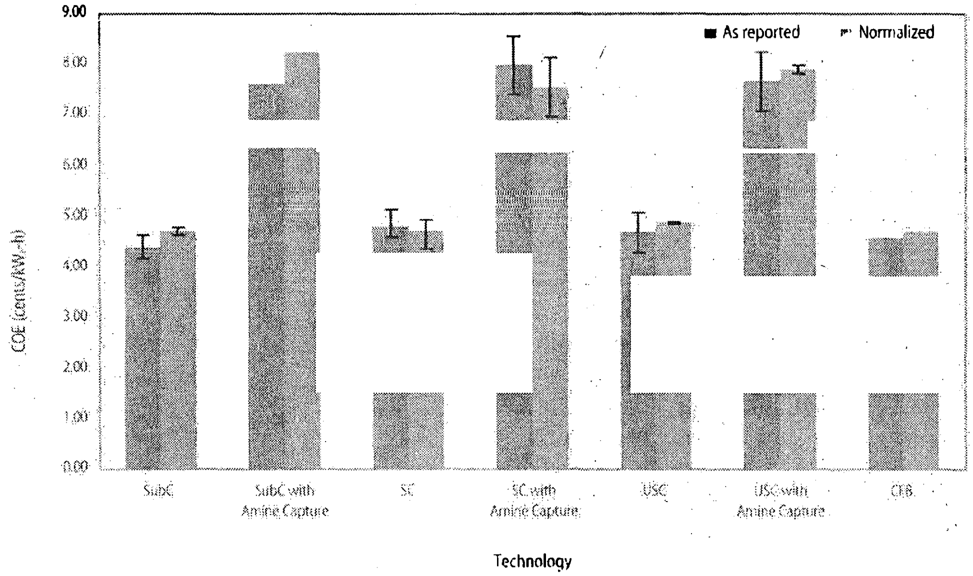
Table 3.4 Economic and Operating Parameters

PARAMETER	VALUE
Capacity factor	85%
Carrying charge factor	15.1%
Fuel cost	$1.50 / MMBtu (HHV)
Total capital requirement (TCR)	12% higher than total plant cost
Life of plant	20 years
Cost year basis	2005
Tax rate	39.2%

The increase in COE in going from no-capture to CO_2 capture ranges from 3.3 ¢/kW$_e$-h for subcritical generation to 2.7 ¢/kW$_e$-h for ultra-supercritical generation (Table 3.1). Over half of this increase is due to higher capital carrying charge resulting from the increased boiler and steam turbine size and the added CO_2 capture, recovery, and compression equipment. About two thirds of the rest is due to higher O&M costs associated with the increased operational scale per kW$_e$ and with CO_2 capture and recovery. For air-blown PC combustion technologies, the cost of avoided CO_2 is about $41 per tonne. These costs are for capture, compression and drying, and do not include the pipeline, transportation and sequestration costs.

The largest cause of the efficiency reduction observed with CO_2 capture for air-blown PC generation (Figure 3.5 and 3.7) is the energy

Figure 3.9 Cost of Electricity from Design Studies As-Reported and Using Normalized Economic and Operating Parameters for Air-Blown Coal Combustion Generating Technologies. Min, Max, and Mean (2005$) for Multiple Studies.



required to regenerate the amine solution (recovering the CO_2), which produces a 5 percentage point efficiency reduction. If this component could be reduced by 50% with an efficient, lower-energy capture technology, the COE for supercritical capture would be reduced by about 0.5 ¢/kW_e-h to about 7.2 ¢/kW_e-h and by about 0.4 ¢/kW_e-h for ultra-supercritical generation. This would reduce the CO_2 avoided cost to about $30 per tonne, a reduction of over 25%.

RETROFITS FOR CO_2 CAPTURE

Because of the large coal-based PC generating fleet in place and the additional capacity that will be constructed in the next two decades, the issue of retrofitting for CO_2 capture is important to the future management of CO_2 emissions. For air-blown PC combustion units, retrofit includes the addition of a process unit to the back end of the flue-gas system to separate and capture CO_2 from the flue gas, and to dry and compress the CO_2 to a supercritical fluid, ready for transport and sequestration. Since the existing coal fleet consists of primarily subcritical units, another option is to rebuild the boiler/steam system, replacing it with high efficiency supercritical or ultra-supercritical technology, including post-combustion CO_2 capture. Appendix 3.E provides a more-detailed analysis of retrofits and rebuilds.

For an MEA retrofit of an existing subcritical PC unit, the net electrical output can be derated by over 40%, e.g., from 500 MW_e to 294 MW_e [36]. In this case, the efficiency decrease is about 14.5 percentage points (Appendix 3.E) compared to about 9.2 percentage points for purpose-built subcritical PC units, one no-capture and the other capture (Table 3.1). With the retrofit, the steam required to regenerate the absorbing solution to recover the CO_2 (Figure 3.4), unbalances the rest of the plant so severely that the efficiency is reduced another 4 to 5 percentage points. In the retrofit case, the original boiler is running at full design capacity, but the original steam turbine is operating at about 60% design rating, which is well off its efficiency optimum. Due to the large power output reduction (41% derating), the retrofit capital cost is estimated to be $1600 per kW_e [36]. This was for a specific unit with adequate space; however, retrofit costs are expected to be highly dependent on location and unit specifics. If the original unit is considered fully paid off, we estimate the COE after retrofit could be slightly less than that for a new purpose-built PC unit with CO_2 capture. However, an operating plant will usually have some residual value, and the reduction in unit efficiency and output, increased on-site space requirements and unit downtime are all complex factors not fully accounted for in this analysis. Based on our analysis, we conclude that retrofits seem unlikely.

Another approach, though not a retrofit, is to rebuild the core of a subcritical PC unit, installing supercritical or ultra-supercritical technology along with post-combustion CO_2 capture. Although the total capital cost for this approach is higher, the cost/kW_e is about the same as for a subcritical retrofit. The resultant plant efficiency is higher, consistent with that of a purpose-built unit with capture; the net power output can essentially be maintained; and the COE is about the same due to the overall higher efficiency. We estimate that an ultra-supercritical rebuild with MEA capture will have an efficiency of 34% and produce electricity for 6.91 ¢/kW_e-h (Appendix 3.E). We conclude that rebuilds including CO_2 capture appear more attractive than retrofits, particularly if they upgrade low-efficiency PC units with high-efficiency technology, including CO_2 capture.

CAPTURE-READY A unit can be considered capture-ready if, at some point in the future, it can be retrofitted for CO_2 capture and sequestration and still be economical to operate [37]. Thus, capture-ready design refers to designing a new unit to reduce the cost of and to facilitate adding CO_2 capture later or at least to not preclude addition of capture later. Capture-ready has elements of ambiguity associated with it because it is not a specific design, but includes a range of investment and design decisions that might be undertaken during unit design and construction. Further, with an uncertain future policy environment, significant pre-investment for CO_2 capture is typically not economically justified [38]. However, some actions make sense. Future PC plants should employ the highest economically efficient technology and leave space for future capture equipment if possible, because this makes retrofits more attractive. Siting should consider proximity to geologic storage.

OXYGEN-BLOWN COAL-BASED POWER GENERATION

The major problems with CO_2 capture from air-blown PC combustion are due to the need to capture CO_2 from flue gas at low concentration and low partial pressure. This is mainly due to the large amount of nitrogen in the flue gas, introduced with the combustion air. Another approach to CO_2 capture is to substitute oxygen for air, essentially removing most of the nitrogen. We refer to this as oxy-fuel PC combustion. A different approach is to gasify the coal and remove the CO_2 prior to combustion. Each of these approaches has advantages and disadvantages, but each offers opportunities for electricity generation with reduced CO_2-capture costs. We consider these approaches next in the form of oxy-fuel PC combustion and Integrated Gasification Combined Cycle (IGCC) power generation.

Table 3.5 summarizes representative performance and economics for oxygen-blown coal-based power generation technologies. Oxy-fuel combustion and IGCC were evaluated using the same bases and assumptions used for the PC combustion technologies (Table 3.1). In this case the estimates are for the N^{th} unit or plant where N is a relatively small number, < 10. In this report, we use gasification and IGCC to mean oxygen-blown gasification or oxygen-blown IGCC. If we mean air-blown gasification, it will be explicitly stated.

OXY-FUEL PULVERIZED COAL (PC) COMBUSTION

This approach to capturing CO_2 from PC units involves burning the coal with ~95%

Table 3.5 Representative Performance and Economics for Oxy-Fuel Pulverized Coal and IGCC Power Generation Technologies, Compared with Supercritical Pulverized Coal

	SUPERCRITICAL PC		SC PC-OXY	IGCC	
	W/O CAPTURE	W/ CAPTURE	W/CAPTURE	W/O CAPTUREQ	W/CAPTURE
PERFORMANCE					
Heat rate (1), Btu/kW$_e$-h	8,868	11,652	11,157	8,891	**10,942**
Generating efficiency (HHV)	38.5%	29.3%	30.6%	38.4%	31.2%
Coal feed, kg/h	184,894	242,950	232,628	185,376	28,155
CO_2 emitted, kg/h	414,903	54,518	52,202	415,983	51,198
CO_2 captured at 90%, kg/h (2)	0	490,662	469,817	0	460,782
CO_2 emitted, g/kW$_e$-h (2)	830	109	104	832	102
COSTS					
Total Plant Cost (3), \$/kW$_e$	1,330	2,140	1,900	1,430	1,890
Inv. Charge, ¢/kW$_e$-h @ 15.1% (4)	2.70	4.34	3.85	2.90	3.83
Fuel, ¢/kW$_e$-h @ \$1.50/MMBtu	1.33	1.75	1.67	1.33	1.64
O&M, ¢/kW$_e$-h	0.75	1.60	1.45	0.90	1.05
COE, ¢/kW$_e$-h	**4.78**	**7.69**	**6.98**	**5.13**	**6.52**
Cost of CO_2 avoided vs. same technology w/o capture (5), \$/tonne		40.4	30.3		19.3
Cost of CO_2 avoided vs. supercritical technology w/o capture (5), \$/tonne		**40.4**	**30.3**		**24.0**

Basis: *500 MW$_e$ plant net output, Illinois # 6 coal (61.2 wt % C, HHV = 25,350 kJ/kg), & 85% capacity factor; for oxy-fuel SC PC CO_2 for sequestration is high purity; for IGCC, GE radiant cooled gasifier for no-capture case and GE full quench gasifier for capture case.*

(1) efficiency = (3414 Btu/kW$_t$-h)/(heat rat

(2) 90% removal used for all capture cases

(3) Based on design studies done between 2000 & 2004, a period of cost stability, updated to 2005\$ using CPI inflation rate. Refers to the Nth plant where N is less than 10. 2007 cost would be higher because of recent rapid increases of engineering and construction costs, up to 30% since 2004.

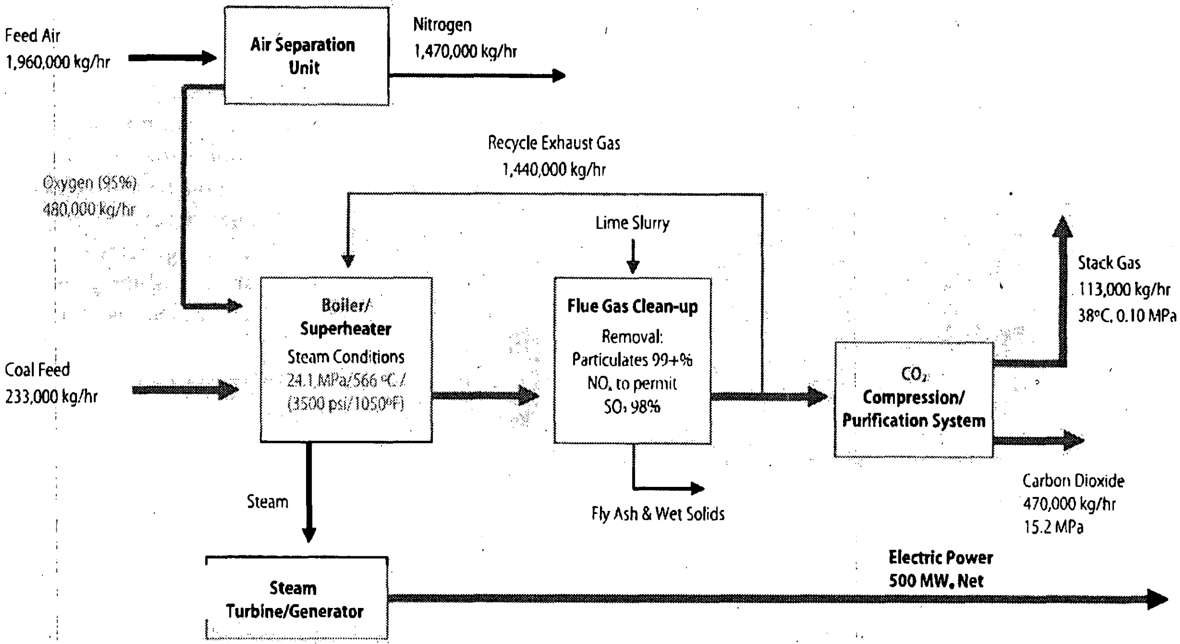
(4) Annual carrying charge of 15.1% from EPRI-TAG methodology, based on 55% debt @ 6.5%, 45% equity @ 11.5%, 39.2% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge

(5) Does not include costs associated with transportation and injection/storage

pure oxygen instead of air as the oxidant[39-41]. The flue gas then consists mainly of carbon dioxide and water vapor. Because of the low concentration of nitrogen in the oxidant gas (95% oxygen), large quantities of flue gas are recycled to maintain design temperatures and required heat fluxes in the boiler, and dry coal-ash conditions. Oxy-fuel enables capture of CO_2 by direct compression of the flue gas but requires an air-separation unit (ASU) to supply the oxygen. The ASU energy consumption is the major factor in reducing the efficiency of oxy-fuel PC combustion. There are no practical reasons for applying oxy-fuel except for CO_2 capture.

A block diagram of a 500 MW$_e$ oxy-fuel generating unit is shown in Figure 3.10 with key material flows shown. Boiler and steam cycle are supercritical. The coal feed rate is higher than that for supercritical PC without capture because of the power consumption of the air separation unit but lower than that for a supercritical PC with MEA CO_2 capture (Table 3.1). In this design, wet FGD is used prior to recycle to remove 95% of the SO_x to avoid boiler corrosion problems and high SO_x concentration in the downstream compression/separation equipment. Non-condensables are removed from the compressed flue gas via a two-stage flash. The composition requirements (purity) of the CO_2 stream for transport and geological injection are yet to be established. The

Figure 3.10 500 MW_e Supercritical Oxy-Fuel Generating Unit with CO_2 Capture



generating efficiency is 30.6% (HHV), which is about 1 percentage point higher than supercritical PC with MEA CO_2 capture. Current design work suggests that the process can be further simplified with SO_x and NO_x removal occurring in the downstream compression & separation stage at reduced cost [42]. Further work is needed.

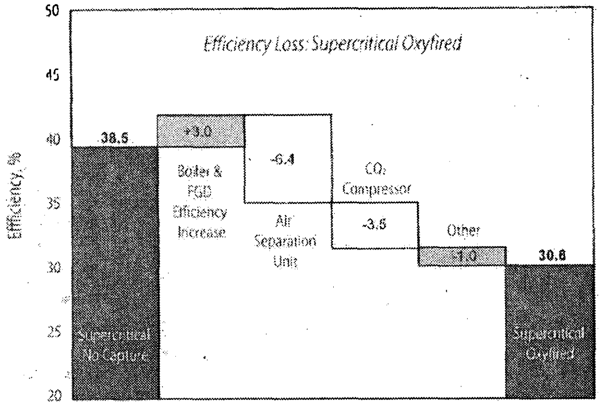
Figure 3.11 shows the parasitic energy requirements for oxy-fuel PC generation with CO_2 capture. Since the steam cycle is supercritical for the oxy-fuel case, supercritical PC is used as the comparison base. The oxy-fuel PC unit has a gain over the air-driven PC case due to improved boiler efficiency and reduced emissions control energy requirements, but the energy requirement of the ASU, which produces a 6.4 percentage point reduction, outweighs this efficiency improvement. The overall efficiency reduction is 8.3 percentage points from supercritical PC. More efficient oxygen separation technology would have a significant impact.

A key unresolved issue is the purity requirements of the supercritical CO_2 stream for geological injection (sequestration). Our design produces a highly-pure CO_2 stream, similar to that from the PC capture cases, but incurs additional cost to achieve this purity level. If this additional purification were not required for transport and geologic sequestration of the CO_2, oxy-fuel PC combustion could gain up to one percentage point in efficiency, and the COE could be reduced by up to 0.4 ¢/kW_e-h.

Oxy-fuel PC combustion is in early commercial development but appears to have considerable potential. It is under active pilot-scale development [43, 44]; Vattenfall plans a 30 MW_{th} CO_2-free coal combustion plant for 2008 start-up[43]; Hamilton, Ontario is developing a 24 MW_e oxy-fuel electricity generation project [45]; and other projects can be expected to be announced.

ECONOMICS Because there is no commercial experience with oxy-fuel combustion and lack of specificity on CO_2 purity requirements for transport and sequestration in a future regulatory regime, the TPC in the limited design studies ranged broadly [13, 39, 41, 46] (Appendix 3.C, Table A-3.C.2, Figure A-3.C.1).

Figure 3.11 **Parasitic Energy Requirement for Oxy-Fuel Pulverized Coal Generation with CO_2 Capture Vs. Supercritical PC without CO_2 Capture**



Only the Parsons study estimated the COE [13]. As with PC combustion, we reviewed the available design studies (Appendix 3.C), our plant component estimate of costs, and external opinion of TPC to arrive at a projected TPC (Table 3.5). We estimated generating efficiency to be 30.6% from the Integrated Environmental Control Model[5]. We applied our normalization economic and operating parameters (Table 3.4) to calculate a COE of 6.98 ¢/kW_e-h (Table 3.5). There may be some upside potential in these numbers if supercritical CO_2 stream purity can be relaxed and design efficiencies gained, but more data are needed.

RETROFITS Oxy-fuel is a good option for retrofitting PC and FBC units for capture since the boiler and steam cycle are less affected by an oxy-fuel retrofit; the major impact being an increased electricity requirement for the auxiliaries, particularly the ASU. Bozzuto estimated a 36% derating for an oxy-fuel retrofit vs. a 41% derating for MEA capture on the same unit [36]. In summary, the oxy-fuel retrofit option costs about 40% less on a \$/kW_e basis, is projected to produce electricity at 10% to 15% less than an MEA retrofit, and has a significantly lower CO_2 avoidance cost (Appendix 3.E). Oxy-fuel rebuild to improve efficiency is another option and appears to be competitive with a high-efficiency MEA rebuild [47].

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

Integrated gasification combined cycle (IGCC) technology produces electricity by first gasifying coal to produce syngas, a mixture of hydrogen and carbon monoxide[48, 49]. The syngas, after clean-up, is burned in a gas turbine which drives a generator. Turbine exhaust goes to a heat recovery generator to raise steam which drives a steam turbine generator. This combined cycle technology is similar to the technology used in modern natural gas fired combined-cycle power plants. Appendix 3.B provides more detail on gasification.

The key component in IGCC is the gasifier, for which a number of different technologies have been developed and are classified and summarized in Table 3.6.

Gasifier operating temperature depends on whether the ash is to be removed as a solid, dry ash or as a high-temperature liquid (slag). Outlet temperature depends on the flow regime and extent of mixing in the gasifier. For the current IGCC plants, oxygen-blown, entrained-flow gasifiers are the technology of choice, although other configurations are being evaluated.

Four 275 to 300 MW_e coal-based IGCC demonstration plants, which are all in commercial operation, have been built in the U.S. and in Europe, each with government financial support [50][33]. Five large IGCC units (250 to 550 MW_e) are operating in refineries gasifying asphalt and refinery wastes [51, 52]; a smaller one (180 MW_e) is operating on petroleum coke. The motivation for pursuing IGCC is the potential for better environmental performance at a lower marginal cost, easier CO_2 capture for sequestration, and higher efficiency. However, the projected capital cost (discussed below) and operational availability of today's IGCC technology make it difficult to compete with conventional PC units at this time.

Table 3.6 Classification and Characteristics of Gasifiers

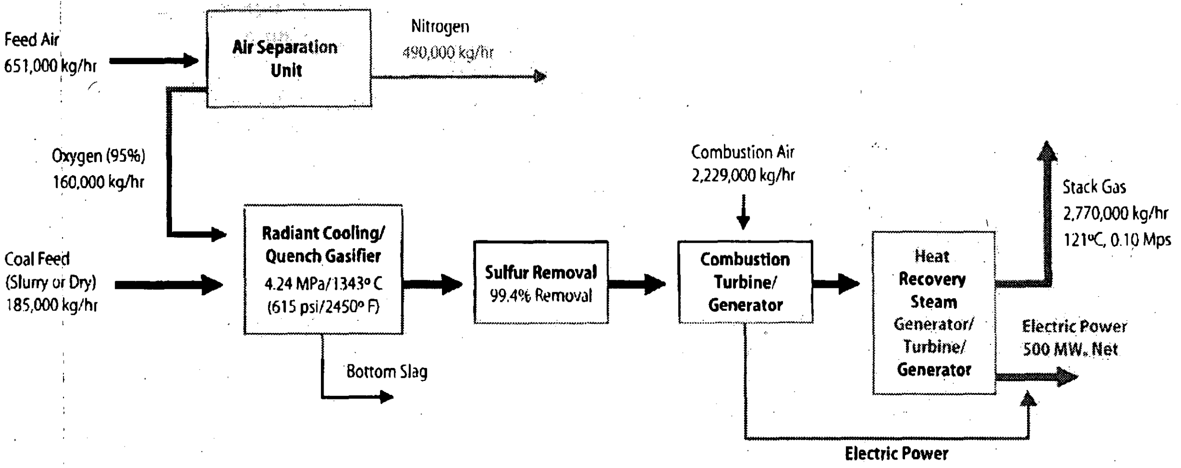
	MOVING BED	FLUID BED	ENTRAINED FLOW
Outlet temperature	Low (425-600 °C)	Moderate (900-1050 °C)	High (1250-1600 °C)
Oxidant demand	Low	Moderate	High
Ash conditions	Dry ash or slagging	Dry ash or agglomerating	Slagging
Size of coal feed	6-50 mm	6-10 mm	< 100 μm
Acceptability of fines	Limited	Good	Unlimited
Other characteristics	Methane, tars and oils present in syngas	Low carbon conversion	Pure syngas, high carbon conversion

IGCC: WITHOUT CO_2 CAPTURE

There are several commercial gasifiers which can be employed with IGCC [53] (see Appendix 3.B for details). A block diagram of a 500 MW_e IGCC unit using a radiant cooling/quench gasifier is shown in Figure 3.12. Finely ground coal, either dry or slurried with water, is introduced into the gasifier, which is operated at pressures between 3.0 and 7.1 MPa (440 to 1050 psi), along with oxygen and water. Oxygen is supplied by an air separation unit (ASU). The coal is partially oxidized raising the temperature to between 1340 and 1400 °C. This assures complete carbon conversion by rapid reaction with steam to form an equilibrium gas mixture that is largely hydrogen and carbon monoxide (syngas). At this temperature, the coal mineral matter melts to form a free-flowing slag. The raw syngas exits the gasification unit at pressure and relatively high temperature, with radiative heat recovery raising high-pressure steam. Adequate technology does not exist to clean-up the raw syngas at high temperature. Instead, proven technologies for gas clean-up require near-ambient temperature. Thus, the raw syngas leaving the gasifier can be quenched by injecting water, or a radiant cooler, and/or a fire-tube (convective) heat exchanger may be used to cool it to the required temperature for removal of particulate matter and sulfur.

The clean syngas is then burned in the combustion turbine. The hot turbine exhaust gas is used to raise additional steam which is sent to the steam turbine in the combined-cycle power block for electricity production. For the configuration shown (See Box 3.1), the overall generating efficiency is 38.4% (HHV), but coal and gasifier type will impact this number.

Figure 3.12 500 MW_e IGCC Unit without CO_2 Capture

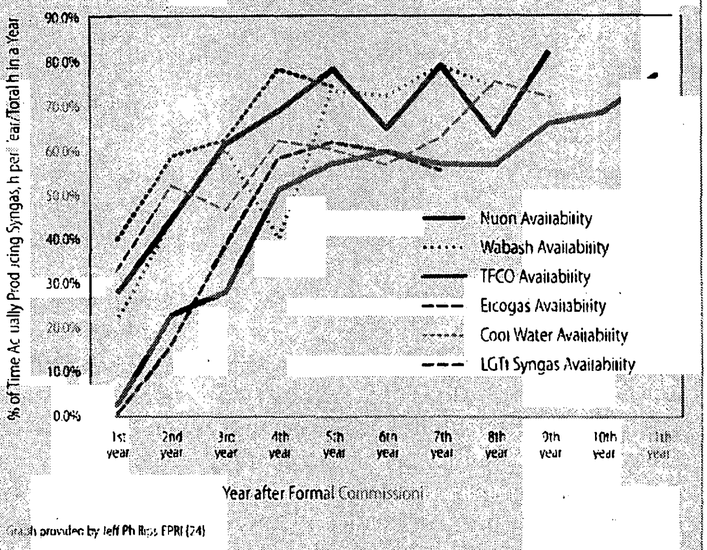


BOX 3.1 IGCC DEMONSTRATIONS

The Cool Water Project sponsored by Southern California Edison in cooperation with GE and Texaco pioneered IGCC with support from the Synthetic Fuels Corporation. This plant demonstrated the feasibility of using IGCC to generate electricity. The plant operated periodically from 1984–1989, and cost over \$2000 /kW$_e$. The project was eventually abandoned, but it provided the basis for the Tampa Electric Polk Power Station. The DOE supported the 250 MW$_e$ Polk Station commercial IGCC demonstration unit, using a Texaco gasifier, which started up in 1996. The total plant cost was about \$1800/kW$_e$. Since it was the first commercial-scale IGCC plant, several optional systems were added, such as a hot-gas clean-up system, which were never used, and were later simplified or removed. When these changes are taken into accounted, the adjusted total plant cost has been estimated at \$1650/kWe (2001\$). This experience has led to some optimism that costs will come down significantly with economies of scale, component standardization, and technical and design advances. However, price increases will raise the nominal cost of plant capital significantly.

The availability of these early IGCC plants was low for the first several years of operation due to a range of problems, as shown in the figure. Many of the problems were design and materials related

Figure Box 3.1 IGCC Availability History *(excluding operation on back-up fuel*



Graph provided by Jeff Ph Ross EPRI (24)

corrected and are unlikely to reapp ire promuch like running a refinery, but al proved to be manageable. Gasifier availability is now 82+% and operating efficiency is ~35.4%. DOE also suppc bash River Gasification Repowering Project, an IGCC de n project using the Dow E-gas gasifier. This demonstration started up in late 1995, has 262 MW$_e$ capacity, and an efficiency of ~38.4%. S ory was similar to that of the Polk unit. LGTI provided the bash.

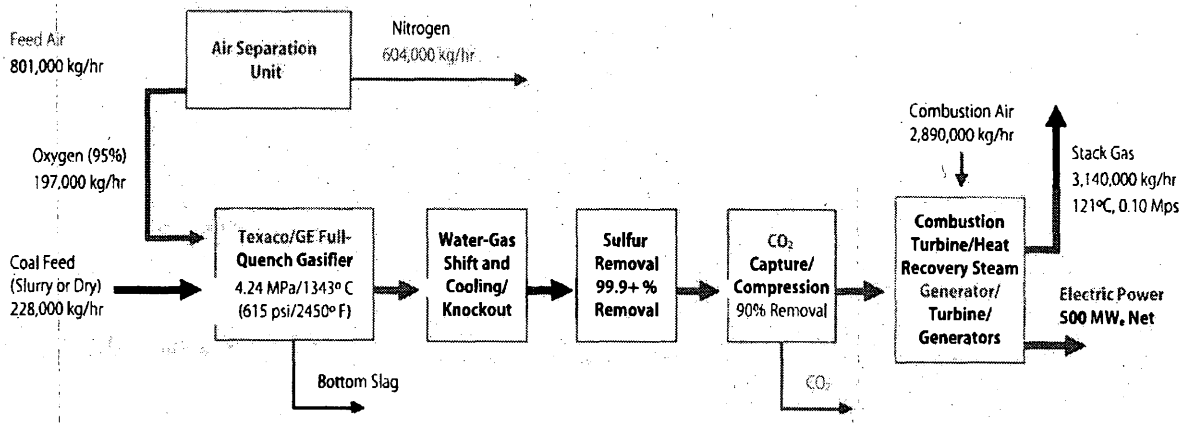
IGCC: WITH PRE-COMBUSTION CO_2 CAPTURE

Applying CO_2 capture to IGCC requires three additional process units: shift reactors, an additional CO_2 separation process, and CO_2 compression and drying. In the shift reactors, CO in the syngas is reacted with steam over a catalyst to produce CO_2 and hydrogen. Because the gas stream is at high pressure and has a high CO_2 concentration, a weakly CO_2-binding physical solvent, such as the glymes in Selexol, can be used to separate out the CO_2. Reducing the pressure releases the CO_2 and regenerates the solvent, greatly reducing the energy requirements for CO_2 capture and recovery compared to the MEA system. Higher pressure in the gasifier improves the energy efficiency of both the separation and CO_2 compression steps. The gas stream to the turbine is now predominantly hydrogen, which requires turbine modifications for efficient operation.

The block diagram with key material flows for a 500 MW$_e$ IGCC unit designed for CO_2 capture is shown in Figure 3.13. For CO_2 capture, a full-quench gasifier is currently considered the optimum configuration. The overall generating efficiency is 31.2% which is a 7.2 percentage point reduction from the IGCC system without CO_2 capture. Adding CO_2 capture requires a 23% increase in the coal feed rate. This compares with coal feed rate increases of 27% for ultra-supercritical PC and 37% for subcritical PC when MEA CO_2 capture is used.

Figure 3.14 illustrates the major impacts on efficiency of adding CO_2 capture to IGCC. CO_2 compression and water gas shift each have

Figure 3.13 500 MW_e IGCC Unit with CO_2 Capture



significant impacts. CO_2 compression is about two-thirds that for the PC cases because the CO_2 is recovered at an elevated pressure. Energy is required in the form of steam for shift reaction. The energy required for CO_2 recovery is lower than for the PC case because of the higher pressures and higher CO_2 concentrations, resulting in less energy intensive separation processes. The total efficiency reduction for IGCC is 7.2 percentage points as compared with 9.2 percentage points for the PC cases. This smaller delta between the no-capture and the capture cases is one of the attractive features of IGCC for application to CO_2 capture.

COST OF ELECTRICITY We analyzed the available IGCC design studies, without and with CO_2 capture, just as we did for PC generation, to arrive at a TPC and our estimate of the COE (Appendix 3.C). There was considerable variation (~\$400/kW_e from min to max) in the TPC from the design studies for both no-capture and capture cases as shown in Figure A-3.C.2 (Appendix 3.C). Each estimate is for a 500 MW_e plant and includes the cost of a spare gasifier. This variation is not surprising in that the studies involved two gasifier types, and there is little commercial experience against which to benchmark costs. There is a variation (min to max) of 0.8 ¢/kW_e-h for no capture and 0.9 ¢/kW_e-h for CO_2 capture in the "as-reported" COE in the studies (Figure A-3.C.4, Appendix 3.C).

We used the same approach to estimate the COE for IGCC as for air-blown PC [54]. For IGCC w/o capture, the COE is about 0.4 cent/kW_e-h higher than for supercritical PC generation, driven by somewhat higher capital and operating costs. The increase in COE for IGCC when CO_2 capture is added is about 1.4 ¢/kW_e-h. This is about half the increase projected for amine capture with supercritical PC. The cost of avoided CO_2 is about \$ 20 per tonne which is about half that for air-blown PC technology. Oxy-fuel PC is in between air-blown PC with amine capture and IGCC with CO_2 capture, based on currently available data.

The COE values developed for this report compare well with the "normalized" values

Figure 3.14 Parasitic Energy Requirement for IGCC with Pre-Combustion CO_2 Capture

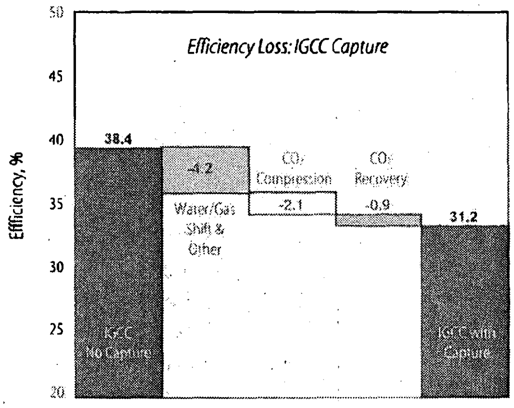


Table 3.7 Relative Cost of Electricity from PC and IGCC Units, without and with CO_2 Capture*

	MIT	GTC	AEP	GE
PC no-capture, reference	1.0	1.0	1.0	1.0
IGCC no-capture	1.05	1.11	1.08	1.06
IGCC capture	1.35	1.39	1.52	1.33
PC capture	1.60	1.69	1.84	1.58

**Included are: the MIT Coal Study results (MIT), the Gasification Technology Council (GTC) [56], General Electric (GE) [57], and American Electric Power (AEP) [58].*

from the design studies evaluated (Figure A-3.C.3 and A-3.C.4). Our values are close to the mean values for super-critical PC without and with capture. For IGCC, our values are at the high end of the range of the other design studies. Our COE for oxy-fuel PC is slightly higher than the "as-reported" values, although it is important to note that oxy-fuel data are based on only two published studies [44, 55].

To further validate the findings in this section, we compared our results with the COE estimates from several sources and summarize these results in Table 3.7. Supercritical PC without capture is set as the reference at 1.0. This suggests that without CO_2 capture, the cost of electricity from IGCC will be from 5 to 11% higher than from supercritical PC. When CO_2 capture is considered, the cost of electricity produced by IGCC would be increased by 30 to 50% over that of supercritical PC without capture, or 25 to 40% over that of IGCC without capture (Table 3.7). However, for supercritical PC with CO_2 capture, the cost of electricity is expected to increase by 60 to 85% over the cost for supercritical PC without capture. These numbers are for green-field plants; they are also for the Nth plant where N is less than 10; and they are based on cost estimates from the relatively stable 2000–2004 cost period.

COAL TYPE AND QUALITY EFFECTS Although gasification can handle almost any carbon-containing material, coal type and quality can have a larger effect on IGCC than on PC generation. IGCC units operate most effectively and efficiently on dry, high-carbon fuels such as bituminous coals and coke. Sulfur content, which affects PC operation, has little effect on IGCC cost or efficiency, although it may impact the size of the sulfur clean-up process. For IGCC plants, coal ash consumes heat energy to melt it, requires more water per unit carbon in the slurry, increases the size of the ASU, and ultimately results in reduced overall efficiency. This is more problematic for slurry-feed gasifiers, and therefore, high-ash coals are more suited to dry-feed systems (Shell), fluid-bed gasifiers (BHEL), or moving-bed gasifiers (Lurgi)[25]. Slurry-fed gasifiers have similar problems with high-moisture coals and coal types with low heating values, such as lignite. These coal types decrease the energy density of the slurry, increase the oxygen demand, and decrease efficiency. Dry-feed gasifiers are favored for high-moisture content feeds.

Coal quality and heating value impact IGCC capital cost and generating efficiency more strongly than they affect these parameters for PC generation (see Figure A-3.A.3, Appendix 3.A) [25]. However, the lower cost of coals with low heating value can offset much of the impact of increased capital cost and reduced efficiency. To illustrate, the capital cost per kW_e and the generating efficiency for an E-Gas IGCC plant designed for Texas lignite are estimated to be 37% higher and 24% lower respectively than if the unit were designed for Pittsburgh #8 coal [25]. For PC combustion the impact is significantly less: 24% higher and 10% lower respectively. As a result, we estimate that the COE for Texas lignite generation is about 20% higher (Figure A-3.A.4) than for Pittsburgh #8 coal because lower coal cost is not sufficient to offset the other increases.

Texas lignite has a high-moisture content and a low-carbon content, which is particularly bad for a slurry-feed gasifier. For a dry-feed gasifier, such as the Shell gasifier, the lignite would compare more favorably. Optimum gasifier type and configuration are influenced by coal type and quality, but there are limited data on these issues.

The available data illustrate several important trends and gaps. First, there is a lack of data and design studies for IGCC with low-heating value, low-quality coals and particularly for gasifiers other than water-slurry fed, entrained-flow systems. Second, PC generation without CO_2 capture is slightly favored over IGCC (lower COE) for high heating value, bituminous coals, but this gap increases as PC steam cycle efficiency increases and as coal heating value decreases. The COE gap is substantially widened (favoring PC) for coals with low heating values, such as lignite. Third, for CO_2 capture, the COE gap for high-heating value bituminous coals is reversed and is substantial (IGCC now being favored); but as coal heating value decreases, the COE gap is substantially narrowed. It appears that ultra-supercritical PC combustion and lower energy consuming CO_2 capture technology, when developed, could have a lower COE than water-slurry fed IGCC with CO_2 capture. This area needs additional study.

U.S. CRITERIA POLLUTANT IMPACTS – ENVIRONMENTAL PERFORMANCE IGCC has inherent advantages with respect to emissions control. The overall environmental footprint of IGCC is smaller than that of PC because of reduced volume and lower leachability of the fused slag, reduced water usage and the potential for significantly lower levels of criteria pollutant emissions. Criteria emissions control is easier because most clean-up occurs in the syngas which is contained at high pressure and has not been diluted by combustion air, i.e. nitrogen. Thus, removal can be more effective and economical than cleaning up large volumes of low-pressure flue gas.

The two operating IGCC units in the U.S. are meeting their permitted levels of emissions, which are similar to those of PC units. However, IGCC units that have been designed to do so can achieve almost order-of-magnitude lower criteria emissions levels than typical current U.S. permit levels and 95+% mercury removal with small cost increases. Appendix 3.D details the environmental performance demonstrated and expected.

Our point COE estimates suggest that although improvements in PC emissions control technology, including mercury control, will increase the COE from PC units, the levels of increased control needed to meet federal emissions levels for 2015 should not make the COE from a PC higher than that from an IGCC. We estimate that the increased emissions control to meet the U.S. 2015 regulations, including mercury, will increase the PC COE by about 0.22 ¢/kW_e-h to 5.00 ¢/kW_e-h and the COE for IGCC to 5.16 ¢/kW_e-h (Appendix 3.D). This does not include the cost of emissions allowances or major, unanticipated regulatory or technological changes. Although the COE numbers for PC and IGCC are expected to approach one another, the cost of meeting criteria pollutant and mercury emissions regulations should not force a change in technology preference from PC to IGCC without CO_2 capture.

However, evaluation and comparison of generating technologies for future construction need to incorporate the effect of uncertainty in the key variables into the economic evaluation. This includes uncertainty in technology performance, including availability and ability to cycle, and cost, in regulatory changes, including timing and cost, and in energy costs and electricity demand/dispatch. Forward estimates for each variable are set, values, bounds and probabilities are established; and a Monte Carlo simulation is done producing a sensitivity analysis of how changes in the variables affect the economics for a given plant. This analysis shows that as permitted future pollutant emissions levels are reduced and the cost of emissions control increases, the NPV cost gap between PC and IGCC will narrow; and at some point, increased emissions control can be expected to lead to IGCC having the lower NPV cost. This, of course, depends on when and the extent to which these changes occur and on how emissions control technology costs change with time and increasing reduction requirements. This type of analysis is used widely in evaluating the commercial economics of large capital projects, of which generation is a set, but is outside the scope of this report.

The same analysis applies to consideration of future CO_2 regulations. The introduction of a CO_2 tax at a future date (dependent on date of imposition, CO_2 tax rate, rate of increase, potential grandfathering and retrofit costs) will drive IGCC to be the lowest NPV cost alternative at some reasonable set of assumptions, and assuming today's technology performance. Substantial technology innovation could change the outcome, as could changing the feed from bituminous coal to lignite.

In light of all these considerations, it is clear that there is no technology today that is an obvious silver bullet.

RETROFITS FOR CO_2 CAPTURE Retrofitting an IGCC for CO_2 capture involves changes in the core of the gasification/combustion/power generation train that are different than the type of changes involved in retrofitting a PC plant for capture. The choice of the gasifier (slurry feed, dry feed), gasifier configuration (full-quench, radiant cooling, convective syngas coolers), acid gas clean-up, operating pressure, and gas turbine are dependent on whether a no-capture or a capture plant is being built. Appendix 3.E treats IGCC retrofitting in more detail.

No-capture designs tend to favor lower pressure [2.8 to 4.1 MPa (400–600 psi)] and increased heat recovery from the gasifier train (radiant coolers and even syngas coolers) to raise more steam for the steam turbine, resulting in a higher net generating efficiency. Dry feed (Shell) provides the highest efficiency and is favored for coals with lower heating value, largely because of their higher moisture content; but the capital costs are higher. On the other hand, capture designs favor higher-pressure [6.0 MPa (1000 psi)] operation, slurry feed, and full-quench mode[59]. Full-quench mode is the most effective method of adding sufficient steam to the raw syngas for the water gas shift reaction without additional, expensive steam raising equipment and/or robbing steam from the steam cycle. Higher pressure reduces the cost of CO_2 capture and recovery, and of CO_2 compression. In addition, the design of a high-efficiency combustion turbine for high hydrogen concentration feeds is different from combustion turbines optimized for syngas, requires further development, and has very little operating experience. In summary, an optimum IGCC unit design for no CO_2 capture is quite different from an optimum unit design for CO_2 capture.

Although retrofitting an IGCC unit for capture would involve significant changes in most components of the unit if it is to result in an optimum CO_2-capture unit, it appears that an IGCC unit could be successfully retrofit by addressing the key needed changes (adding shift reactors, an additional Selexol unit, and CO_2 compression/drying). In this case, retrofitting an IGCC unit would appear to be less expensive than retrofitting a PC unit, although it would not be an optimum CO_2-capture unit. Pre-investment for later retrofit will generally be unattractive and will be unlikely for a technology that is trying to establish a competitive position. However, for IGCC, additional space could be set aside to facilitate future retrofit potential. In addition, planning for a possible retrofit for capture could influence initial design choices (e.g., radiant quench vs. full quench).

IGCC OPERATIONAL HISTORY In addition to cost, IGCC has to overcome the perception of poor availability and operability. Appendix 3.B provides more detail, beyond that discussed below. For each of the current IGCC demonstration plants, 3 to 5 years was required to reach 70 to 80% availability after commercial operation was initiated. Because of the complexity of the IGCC process, no single process unit or component of the total system is responsible for the majority of the unplanned shutdowns that these units have experienced, reducing IGCC unit availability. However, the gasification complex or block has been the largest factor in reducing IGCC availability and operability. Even after reaching 70 to 80% availability, operational performance has not typically exceeded 80% consistently. A detailed analysis of the operating history of the Polk Power Station over the last few years suggests that it is very similar to operating a petroleum refinery, requiring continuous attention to avert, solve and prevent mechanical, equipment and process problems that periodically arise. In this sense, the operation of an IGCC unit is significantly different from the operation of a PC unit, and requires a different operational philosophy and strategy.

The Eastman Chemical Coal Gasification Plant uses a Texaco full-quench gasifier and a backup gasifier (a spare) and has achieved less than 2% forced outage from the gasification/syngas system over almost 20 years operation. Sparing is one approach to achieving better online performance, and a vigorous equipment health maintenance and monitoring program is another. There are five operating in-refinery IGCC units based on petroleum residuals and/or coke; two are over 500 MW_e each. Several other refinery-based gasification units produce steam, hydrogen, synthesis gas, and power. They have typically achieved better operating performance, more quickly than the coal-based IGCC units. Three more are under construction. It is fair to say that IGCC is well established commercially in the refinery setting. IGCC can also be considered commercial in the coal-based electricity generation setting, but in this setting it is neither well established nor mature. As such, it is likely to undergo significant change as it matures.

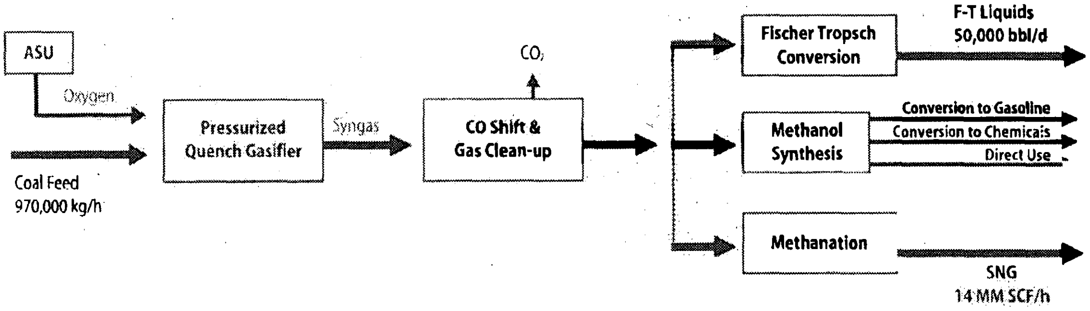
Our analysis assumes that IGCC plants, with or without capture, can "cycle" to follow load requirements. However, there is relatively little experience with cycling of IGCC plants (although the 250 MW_e Shell IGCC at Buggenum operated for 2 years in a load following mode under grid dispatch in the general range 50–100% load, and the Negishi IGCC unit routinely cycles between 100 to 75% load, both up and down, in 30 min) so considerable uncertainty exists for these performance features. Because an IGCC plant is "integrated" in its operation any shortfall in this performance could cause considerable increase in both variable and capital cost.

COAL TO FUELS AND CHEMICALS

Rather than burning the syngas produced by coal gasification in a combustion turbine, it can be converted to synthetic fuels and chemicals. The syngas is first cleaned of particulates and sulfur compounds and undergoes water gas shift to obtain the desired hydrogen to CO ratio. Fischer-Tropsch technology can be used to convert this syngas or "synthesis gas" into predominantly high-quality diesel fuel, along with naphtha and LPG. Fischer-Tropsch technology involves the catalytic conversion of the hydrogen and carbon monoxide in the synthesis gas into fuel range hydrocarbons. This technology has been used in South Africa since the 1950's, and 195,000 barrels per day of liquid fuels are currently being produced in that country by Fischer-Tropsch. Synthesis gas can also be converted to methanol which can be used directly or be upgraded into high-octane gasoline. For gaseous fuels production, the synthesis gas can be converted into methane, creating synthetic natural gas (SNG). Figure 3.15 illustrates three potential coal to fuels or chemicals process options. This type of process configuration could be called a coal refinery. More details are presented in Appendix 3.F.

Methanol production from coal-based synthesis gas is also a route into a broad range of chemicals. The naphtha and lighter hydrocarbons produced by Fischer-Tropsch are another route to produce a range of chemicals, in addition to the diesel fuel produced. The largest commodity chemical produced from

Figure 3.15 Coal to Liquid Fuels, Synthetic Natural Gas and Chemicals



synthesis gas today is ammonia. Although most U.S. ammonia plants were designed to produce their syngas by reforming natural gas, world wide there are a significant number of ammonia plants that use syngas from coal gasification and more are under construction. These routes to chemicals are easily integrated into a coal refinery, as is power generation. Commercially, these processes will be applied to the extent that they make economic sense and are in the business portfolio of the operating company.

For such a coal refinery, all the carbon entering in the coal exits as carbon in the fuels or chemicals produced, or as CO_2 in concentrated gas form that could easily be compressed for sequestration. In this case, of order 50% to 70% of the carbon in the coal would be in the form of CO_2 ready for sequestration. If the gasification product were hydrogen, then essentially all the carbon entering the refinery in the coal would appear in concentrated CO_2 streams that could be purified and compressed for sequestration. Without carbon capture and sequestration (CCS), we estimate that the Fischer-Tropsch fuels route produces about 150% more CO_2 as compared with the use of the petroleum-derived fuel products. For SNG, up to 175% more CO_2 is emitted than if regular natural gas is burned. With CCS, the full fuel-cycle CO_2 emissions for both liquid fuel and SNG are comparable with traditional production and utilization methods. Fortunately, CCS does not require major changes to the process, large amounts of additional capital, or significant energy penalties because the CO_2 is a relatively pure byproduct of the process at intermediate pressure. CCS requires drying and compressing to supercritical pressure. As a result of this the CO_2 avoided cost for CCS in conjunction with fuels and chemicals manufacture from coal is about one third of the CO_2 avoided cost for IGCC.

CITATIONS AND NOTES

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7. Other modeling tools could have been used. Each would have given somewhat different results because of the myriad of design and parameter choices, and engineering approximations included in each. Model results are consistent with other models when operational differences are accounted for (Appendix 3-B).

8. U.S. engineering pracitce is to use the higher heating value (HHV) of the fuel in calculating generating efficiency, and electrical generating efficiencies are expressed on an HHV basis. Fuel prices are also normally quoted on an HHV basis. The HHV of a fuel includes the heat recovered in condensing the water formed in combustion to liquid water. If the water is not condensed, less heat is recovered; and the value is the Lower Heating Value (LHV) of the fuel.

9. Of these variables, steam cycle severity (steam temperature and pressure) is the most important. Steam cycle severity increases from subcritical to supercritical to ultra-supercritical. Increasing severity means that the steam carries more available energy to the steam turbine, resulting in higher generating efficiency.

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14. Tonne is used to refer to metric or long tonnes, which are 2200 pounds or 1000 kg, and Ton is used to refer to a short ton which is 2000 pounds. Although both are used in this report, we are consistent in distinguishing tonne and ton.

15. Changes in operating parameters, excluding emissions control levels, can shift the generating efficiency by upwards to one percentage point. Large changes in emissions control levels can have a similarly large effect. A conservative set of parameters was used in this study, giving a generating efficiency somewhat below the midpoint of the range. See Appendix 3-B and Appendix 3-D for more detail.

16. As steam pressure and temperature are increased above 218 atm (3200 psi) and 375° C (706° F), respectively, the water-steam system becomes supercritical. Under these conditions the two-phase mixture of liquid water and gaseous steam disappears. Instead with increasing temperature the fluid phase undergoes gradual transition from a single dense liquid-like phase to a less dense vapor-like phase, characterized by its own unique set of physical properties.

17. However, due to materials-related boiler tube fatigue and creep stress in headers, steamlines, and in the turbines, the utility industry moved back to subcritical technology for new U. S. coal power plants. Even after the materials problems were resolved there was not a move back to supercritical PC because at the very cheap price of U. S. coal, the added plant cost could not be justified on coal feed rate savings.

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Attachment 2

Comments of
Environmental Law & Policy Center, Sierra Club and Valley Watch Inc.

IPCC Special Report

Carbon Dioxide Capture and Storage

Technical Summary

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Contents

1. Introduction and framework of this report

Carbon dioxide capture and storage (CCS), the subject of this Special Report, is considered as one of the options for reducing atmospheric emissions of CO_2 from human activities. The purpose of this Special Report is to assess the current state of knowledge regarding the technical, scientific, environmental, economic and societal dimensions of CCS and to place CCS in the context of other options in the portfolio of potential climate change mitigation measures.

The structure of this Technical Summary follows that of the Special Report. This introductory section presents the general framework for the assessment together with a brief overview of CCS systems. Section 2 then describes the major sources of CO_2, a step needed to assess the feasibility of CCS on a global scale. Technological options for CO_2 capture are then discussed in Section 3, while Section 4 focuses on methods of CO_2 transport. Following this, each of the storage options is addressed. Section 5 focuses on geological storage, Section 6 on ocean storage, and Section 7 on mineral carbonation and industrial uses of CO_2. The overall costs and economic potential of CCS are then discussed in Section 8, followed by an examination in Section 9 of the implications of CCS for greenhouse gas emissions inventories and accounting. The Technical Summary concludes with a discussion of gaps in knowledge, especially those critical for policy considerations.

Overview of CO_2 capture and storage

CO_2 is emitted principally from the burning of fossil fuels, both in large combustion units such as those used for electric power generation and in smaller, distributed sources such as automobile engines and furnaces used in residential and commercial buildings. CO_2 emissions also result from some industrial and resource extraction processes, as well as from the burning of forests during land clearance. CCS would most likely be applied to large point sources of CO_2, such as power plants or large industrial processes. Some of these sources could supply decarbonized fuel such as hydrogen to the transportation, industrial and building sectors, and thus reduce emissions from those distributed sources.

CCS involves the use of technology, first to collect and concentrate the CO_2 produced in industrial and energy-related sources, transport it to a suitable storage location, and then store it away from the atmosphere for a long period of time. CCS would thus allow fossil fuels to be used with low emissions of greenhouse gases. Application of CCS to biomass energy sources could result in the net removal of CO_2 from the atmosphere (often referred to as 'negative emissions') by capturing and storing the atmospheric CO_2 taken up by the biomass, provided the biomass is not harvested at an unsustainable rate.

Figure TS.1 illustrates the three main components of the CCS process: capture, transport and storage. All three components are found in industrial operations today, although mostly not for the purpose of CO_2 storage. The capture step involves separating CO_2 from other gaseous products. For fuel-burning processes such as those in power plants, separation technologies can be used to capture CO_2 after combustion or to decarbonize the fuel before combustion. The transport step may be required to carry captured CO_2 to a suitable storage site located at a distance from the CO_2 source. To facilitate both transport and storage, the captured CO_2 gas is typically compressed to a high density at the capture facility. Potential storage methods include injection into underground geological formations, injection into the deep ocean, or industrial fixation in inorganic carbonates. Some industrial processes also might utilize and store small amounts of captured CO_2 in manufactured products.

The technical maturity of specific CCS system components varies greatly. Some technologies are extensively deployed in mature markets, primarily in the oil and gas industry, while others are still in the research, development or demonstration phase. Table TS.1 provides an overview of the current status of all CCS components. As of mid-2005, there have been three commercial projects linking CO_2 capture and geological storage: the offshore Sleipner natural gas processing project in Norway, the Weyburn Enhanced Oil Recovery (EOR)[1] project in Canada (which stores CO_2 captured in the United States) and the In Salah natural gas project in Algeria. Each captures and stores 1–2 $MtCO_2$ per year. It should be noted, however, that CCS has not yet been applied at a large (e.g., 500 MW) fossil-fuel power plant, and that the overall system may not be as mature as some of its components.

[1] In this report, EOR means enhanced oil recovery using CO_2

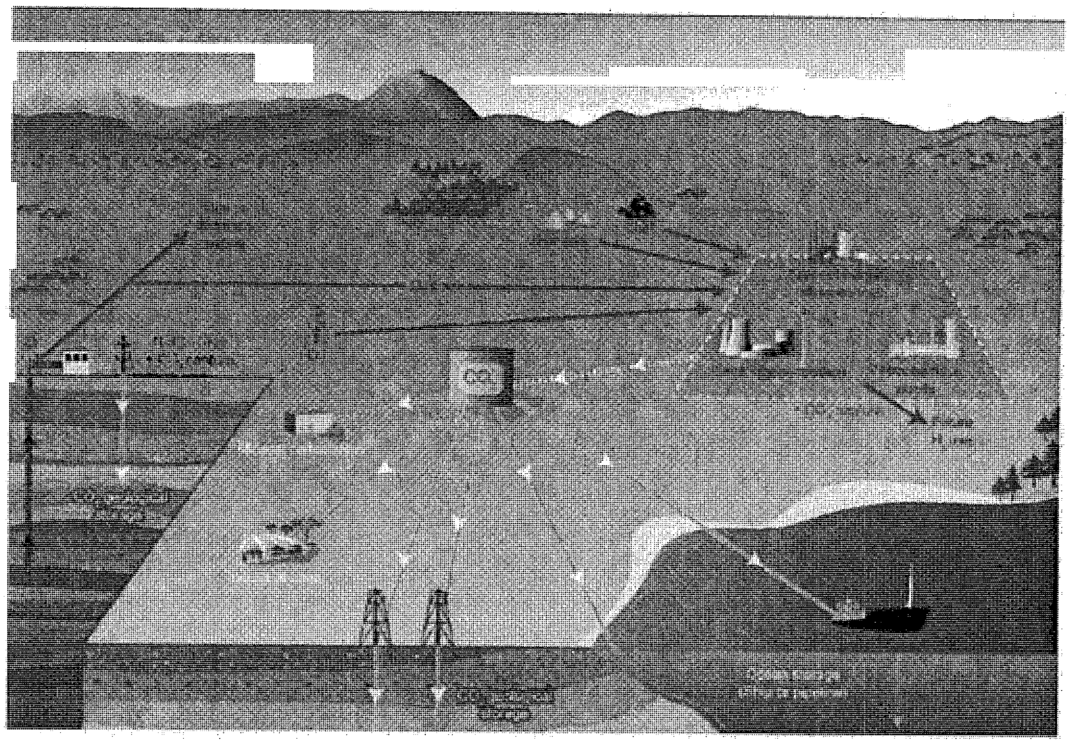

Figure TS.1. Schematic diagram of possible CCS systems. It shows the sources for which CCS might be relevant, as well as CO_2 transport and storage options (Courtesy CO2CRC).

Why the interest in CO_2 capture and storage?

In 1992, international concern about climate change led to the United Nations Framework Convention on Climate Change (UNFCCC). The ultimate objective of that Convention is the "stabilization of greenhouse gas concentrations in the atmosphere at a level that prevents dangerous anthropogenic interference with the climate system". From this perspective, the context for considering CCS (and other mitigation options) is that of a world constrained in CO_2 emissions, consistent with the international goal of stabilizing atmospheric greenhouse gas concentrations. Most scenarios for global energy use project a substantial increase of CO_2 emissions throughout this century in the absence of specific actions to mitigate climate change. They also suggest that the supply of primary energy will continue to be dominated by fossil fuels until at least the middle of the century (see Section 8). The magnitude of the emissions reduction needed to stabilize the atmospheric concentration of CO_2 will depend on both the level of future emissions (the baseline) and the desired target for long-term CO_2 concentration: the lower the stabilization target and the higher the baseline emissions, the larger the required reduction in CO_2 emissions. IPCC's Third Assessment Report (TAR) states that, depending on the scenario considered, cumulative emissions of hundreds or even thousands of gigatonnes of CO_2 would need to be prevented during this century to stabilize the CO_2 concentration at 450 to 750 ppmv[2]. The TAR also finds that, "most model results indicate that known technological options[3] could achieve a broad range of atmospheric CO_2 stabilization levels", but that "no single technology option will provide all of the emissions reductions needed". Rather, a combination of mitigation measures will be needed to achieve stabilization. These known technological options are available for stabilization, although the TAR cautions that, "implementation would require associated socio-economic and institutional changes".

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ppmv is parts per million by volume

[3] "Known technological options" refer to technologies that are currently at the operation or pilot-plant stages, as referred to in the mitigation scenarios discussed in IPCC's Third Assessment Report. The term does not include any new technologies that will require drastic technological breakthroughs. It can be considered to represent a conservative estimate given the length of the scenario period.

Table TS.1. Current maturity of CCS system components. An X indicates the highest level of maturity for each component. There are also less mature technologies for most components.

CCS component	CCS technology	Research phase [a]	Demonstration phase [b]	Economically feasible under specific conditions [c]	Mature market [d]
Capture	Post-combustion			X	
	Pre-combustion			X	
	Oxyfuel combustion		X		
	Industrial separation (natural gas processing, ammonia production)				X
Transportation	Pipeline				X
	Shipping			X	
Geological storage	Enhanced Oil Recovery (EOR)				X[e]
	Gas or oil fields			X	
	Saline formations			X	
	Enhanced Coal Bed Methane recovery (ECBM)[f]		X		
Ocean storage	Direct injection (dissolution type)	X			
	Direct injection (lake type)	X			
Mineral carbonation	Natural silicate minerals	X			
	Waste materials		X		
Industrial uses of CO_2					X

[a] Research phase means that the basic science is understood, but the technology is currently in the stage of conceptual design or testing at the laboratory or bench scale, and has not been demonstrated in a pilot plant.

[b] Demonstration phase means that the technology has been built and operated at the scale of a pilot plant, but further development is required before the technology is required before the technology is ready for the design and construction of a full-scale system.

[c] Economically feasible under specific conditions means that the technology is well understood and used in selected commercial applications, for instance if there is a favourable tax regime or a niche market, or processing on in the order of 0.1 $MtCO_2$ yr^{-1}, with few (less than 5) replications of the technology.

[d] Mature market means that the technology is now in operation with multiple replications of the technology worldwide.

[e] CO_2 injection for EOR is a mature market technology, but when used for CO_2 storage, it is only economically feasible under specific conditions.

[f] ECBM is the use of CO_2 to enhance the recovery of the methane present in unminable coal beds through the preferential adsorption of CO_2 on coal. Unminable coal beds are unlikely to ever be mined, because they are too deep or too thin. If subsequently mined, the stored CO_2 would be released.

In this context, the availability of CCS in the portfolio of options for reducing greenhouse gas emissions could facilitate the achievement of stabilization goals. Other technological options, which have been examined more extensively in previous IPCC assessments, include: (1) reducing energy demand by increasing the efficiency of energy conversion and/or utilization devices; (2) decarbonizing energy supplies (either by switching to less carbon-intensive fuels (coal to natural gas, for example), and/or by increasing the use of renewable energy sources and/or nuclear energy (each of which, on balance, emit little or no CO_2); (3) sequestering CO_2 through the enhancement of natural sinks by biological fixation; and (4) reducing non-CO_2 greenhouse gases. Model results presented later in this report suggest that use of CCS in conjunction with other measures could significantly reduce the cost of achieving stabilization and would increase flexibility in achieving these reductions. The heavy worldwide reliance on fossil fuels today (approximately 80% of global energy use), the potential for CCS to reduce CO_2 emissions over the next century, and the compatibility of CCS systems with current energy infrastructures explain the interest in this technology.

Major issues for this assessment

There are a number of issues that need to be addressed in trying to understand the role that CCS could play in mitigating climate change. Questions that arise, and that are addressed in different sections of this Technical Summary, include the following:

- What is the current status of CCS technology?
- What is the potential for capturing and storing CO_2?
- What are the costs of implementation?
- How long should CO_2 be stored in order to achieve significant climate change mitigation?
- What are the health, safety and environment risks of CCS?
- What can be said about the public perception of CCS?
- What are the legal issues for implementing CO_2 storage?
- What are the implications for emission inventories and accounting?
- What is the potential for the diffusion and transfer of CCS technology?

When analyzing CCS as an option for climate change mitigation, it is of central importance that all resulting emissions from the system, especially emissions of CO_2, be identified and assessed in a transparent way. The importance of taking a "systems" view of CCS is therefore stressed, as the selection of an appropriate system boundary is essential for proper analysis. Given the energy requirements associated with capture and some storage and utilization options, and the possibility of leaking storage reservoirs, it is vital to assess the CCS chain as a whole.

From the perspectives of both atmospheric stabilization and long-term sustainable development, CO_2 storage must extend over time scales that are long enough to contribute significantly to climate change mitigation. This report expresses the duration of CO_2 storage in terms of the 'fraction retained', defined as the fraction of the cumulative mass of CO_2 injected that is retained in a storage reservoir over a specified period of time. Estimates of such fractions for different time periods and storage options are presented later. Questions arise not only about how long CO_2 will remain stored, but also what constitutes acceptable amounts of slow, continuous leakage[4] from storage. Different approaches to this question are discussed in Section 8.

CCS would be an option for countries that have significant sources of CO_2 suitable for capture, that have access to storage sites and experience with oil or gas operations, and that need to satisfy their development aspirations in a carbon-constrained environment. Literature assessed in the IPCC Special Report 'Methodological and Technological Issues and Technology Transfer' indicates that there are many potential barriers that could inhibit deployment in developing countries, even of technologies that are mature in industrialized countries. Addressing these barriers and creating conditions that would facilitate diffusion of the technology to developing countries would be a major issue for the adoption of CCS worldwide.

2. Sources of CO_2

This section describes the major current anthropogenic sources of CO_2 emissions and their relation to potential storage sites. As noted earlier, CO_2 emissions from human activity arise from a number of different sources, mainly from the combustion of fossil fuels used in power generation, transportation, industrial processes, and residential and commercial buildings. CO_2 is also emitted during certain industrial processes like cement manufacture or hydrogen production and during the combustion of biomass. Future emissions are also discussed in this section.

Current CO_2 sources and characteristics

To assess the potential of CCS as an option for reducing global CO_2 emissions, the current global geographical relationship between large stationary CO_2 emission sources and their proximity to potential storage sites has been examined. CO_2 emissions in the residential, commerical and transportation sectors have not been considered in this analysis because these emission sources are individually small and often mobile, and therefore unsuitable for capture and storage. The discussion here also includes an analysis of potential future sources of CO_2 based on several scenarios of future global energy use and emissions over the next century.

Globally, emissions of CO_2 from fossil-fuel use in the year 2000 totalled about 23.5 $GtCO_2\ yr^{-1}$ (6 $GtC\ yr^{-1}$). Of this, close to 60% was attributed to large (>0.1 $MtCO_2\ yr^{-1}$) stationary emission sources (see Table TS.2). However, not all of these sources are amenable to CO_2 capture. Although the sources evaluated are distributed throughout the world, the database reveals four particular clusters of emissions: North America (midwest and eastern USA), Europe (northwest region), East Asia (eastern coast of China) and South Asia (Indian subcontinent). By contrast, large-scale biomass sources are much smaller in number and less globally distributed.

Currently, the vast majority of large emission sources have CO_2 concentrations of less than 15% (in some cases, substantially less). However, a small portion (less than 2%) of the fossil fuel-based industrial sources have CO_2 concentrations in excess of 95%. The high-concentration sources are potential candidates for the early implementation

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[4] With respect to CO_2 storage, leakage is defined as the escape of injected fluid from storage. This is the most common meaning used in this Summary. If used in the context of trading of carbon dioxide emission reductions, it may signify the change in anthropogenic emissions by sources or removals by sinks which occurs outside the project boundary.

Table TS.2. Profile by process or industrial activity of worldwide large stationary CO_2 sources with emissions of more than 0.1 $MtCO_2$ per year.

Process	Number of sources	Emissions ($MtCO_2$ yr^{-1})
Fossil fuels		
Power	4,942	10,539
Cement production	1,175	932
Refineries	638	798
Iron and steel industry	269	646
Petrochemical industry	470	379
Oil and gas processing	N/A	50
Other sources	90	33
Biomass		
Bioethanol and bioenergy	303	91
Total	**7,887**	**13,466**

of CCS because only dehydration and compression would be required at the capture stage (see Section 3). An analysis of these high-purity sources that are within 50 km of storage formations and that have the potential to generate revenues (via the use of CO_2 for enhanced hydrocarbon production through ECBM or EOR) indicates that such sources currently emit approximately 360 $MtCO_2$ per year. Some biomass sources like bioethanol production also generate high-concentration CO_2 sources which could also be used in similar applications.

The distance between an emission location and a storage site can have a significant bearing on whether or not CCS can play a significant role in reducing CO_2 emissions. Figure TS.2a depicts the major CO_2 emission sources (indicated by dots), and Figure TS.2b shows the sedimentary basins with geological storage prospectivity (shown in different shades of grey). In broad terms, these figures indicate that there is potentially good correlation between major sources and prospective sedimentary basins, with many sources lying either directly above, or within reasonable distances (less than 300 km) from areas with potential for geological storage. The basins shown in Figure TS.2b have not been identified or evaluated as suitable storage reservoirs; more detailed geological analysis on a regional level is required to confirm the suitability of these potential storage sites.

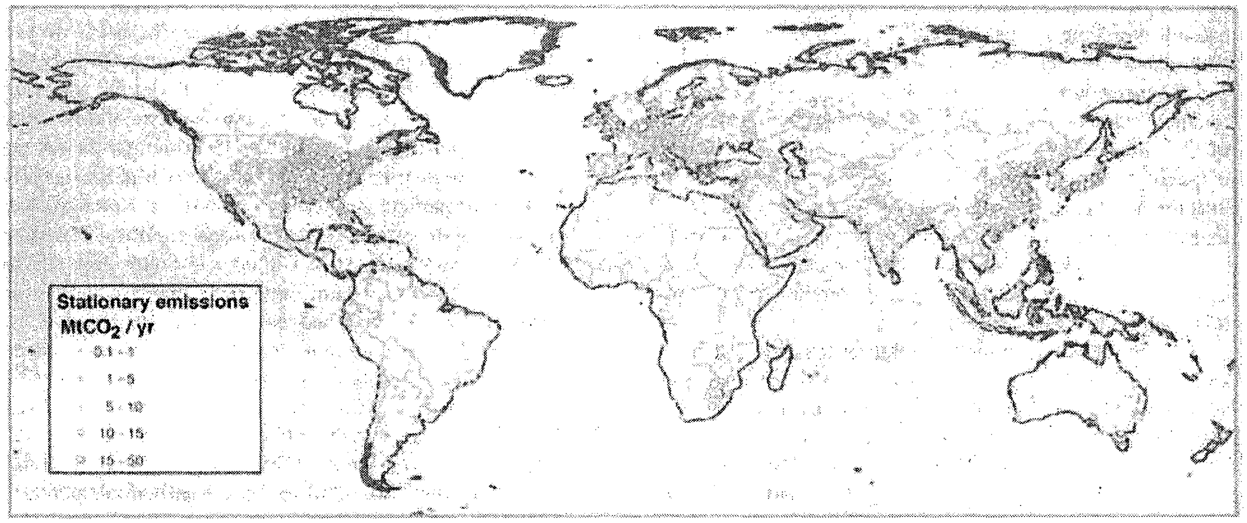

Figure TS.2a. Global distribution of large stationary sources of CO_2 (based on a compilation of publicly available information on global emission sources, IEA GHG 2002)

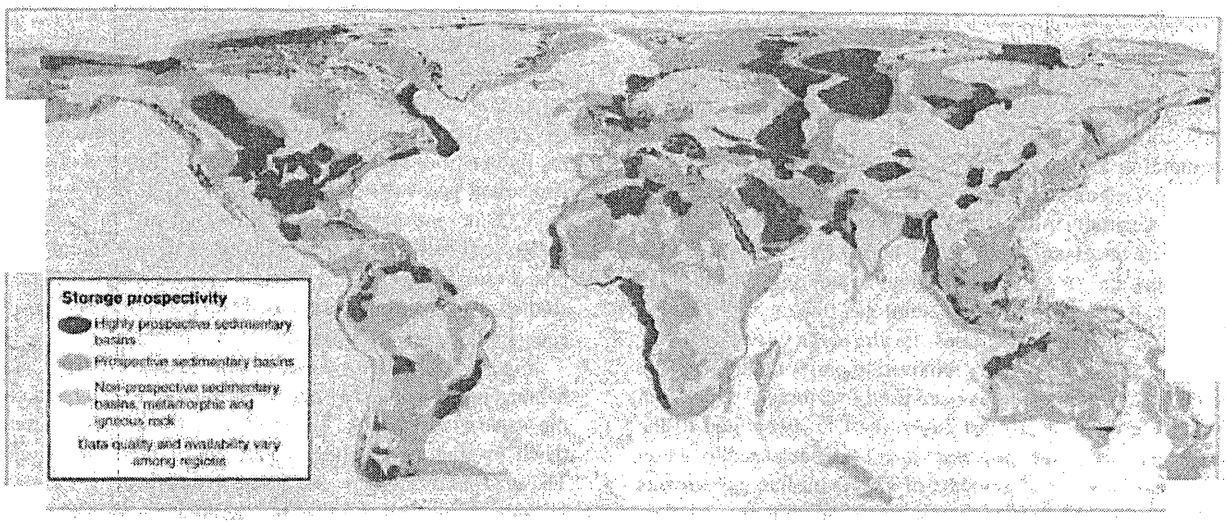

Figure TS.2b. Prospective areas in sedimentary basins where suitable saline formations, oil or gas fields, or coal beds may be found. Locations for storage in coal beds are only partly included. Prospectivity is a qualitative assessment of the likelihood that a suitable storage location is present in a given area based on the available information. This figure should be taken as a guide only, because it is based on partial data, the quality of which may vary from region to region, and which may change over time and with new information (Courtesy of Geoscience Australia).

Future emission sources

In the IPCC Special Report on Emission Scenarios (SRES), the future emissions of CO_2 are projected on the basis of six illustrative scenarios in which global CO_2 emissions range from 29 to 44 $GtCO_2$ (8–12 GtC) per year in 2020, and from 23 to 84 $GtCO_2$ (6–23 GtC) per year in 2050. It is projected that the number of CO_2 emission sources from the electric power and industrial sectors will increase significantly until 2050, mainly in South and East Asia. By contrast, the number of such sources in Europe may decrease slightly. The proportion of sources with high and low CO_2 content will be a function of the size and rate of introduction of plants employing gasification or liquefaction of fossil fuels to produce hydrogen, or other liquid and gaseous products. The greater the number of these plants, the greater the number of sources with high CO_2 concentrations technically suitable for capture.

The projected potential of CO_2 capture associated with the above emission ranges has been estimated at an annual 2.6 to 4.9 $GtCO_2$ by 2020 (0.7–1.3 GtC) and 4.7 to 37.5 $GtCO_2$ by 2050 (1.3–10 GtC). These numbers correspond to 9–12%, and 21–45% of global CO_2 emissions in 2020 and 2050, respectively. The emission and capture ranges reflect the inherent uncertainties of scenario and modelling analyses, and the technical limitations of applying CCS. These scenarios only take into account CO_2 capture from fossil fuels, and not from biomass sources. However, emissions from large-scale biomass conversion facilities could also be technically suitable for capture.

The potential development of low-carbon energy carriers is relevant to the future number and size of large, stationary CO_2 sources with high concentrations. Scenarios also suggest that large-scale production of low-carbon energy carriers such as electricity or hydrogen could, within several decades, begin displacing the fossil fuels currently used by small, distributed sources in residential and commercial buildings and in the transportation sector (see Section 8). These energy carriers could be produced from fossil fuels and/or biomass in large plants that would generate large point sources of CO_2 (power plants or plants similar to current plants producing hydrogen from natural gas). These sources would be suitable for CO_2 capture. Such applications of CCS could reduce dispersed CO_2 emissions from transport and from distributed energy supply systems. At present, however, it is difficult to project the likely number, size, or geographical distribution of the sources associated with such developments.

3. Capture of CO_2

This section examines CCS capture technology. As shown in Section 2, power plants and other large-scale industrial processes are the primary candidates for capture and the main focus of this section.

Capture technology options and applications

The purpose of CO_2 capture is to produce a concentrated stream of CO_2 at high pressure that can readily be transported to a storage site. Although, in principle, the entire gas stream containing low concentrations of CO_2 could be transported and injected underground, energy costs and other associated costs generally make this approach impractical. It is therefore necessary to produce a nearly pure CO_2 stream for transport and storage. Applications separating CO_2 in large industrial plants, including natural gas treatment plants and ammonia production facilities, are already in operation today. Currently, CO_2 is typically removed to purify other industrial gas streams. Removal has been used for storage purposes in only a few cases; in most cases, the CO_2 is emitted to the atmosphere. Capture processes also have been used to obtain commercially useful amounts of CO_2 from flue gas streams generated by the combustion of coal or natural gas. To date, however, there have been no applications of CO_2 capture at large (e.g., 500 MW) power plants.

Depending on the process or power plant application in question, there are three main approaches to capturing the CO_2 generated from a primary fossil fuel (coal, natural gas or oil), biomass, or mixtures of these fuels:

Post-combustion systems separate CO_2 from the flue gases produced by the combustion of the primary fuel in air. These systems normally use a liquid solvent to capture the small fraction of CO_2 (typically 3–15% by volume) present in a flue gas stream in which the main constituent is nitrogen (from air). For a modern pulverized coal (PC) power plant or a natural gas combined cycle (NGCC) power plant, current post-combustion capture systems would typically employ an organic solvent such as monoethanolamine (MEA).

Pre-combustion systems process the primary fuel in a reactor with steam and air or oxygen to produce a mixture consisting mainly of carbon monoxide and hydrogen ("synthesis gas"). Additional hydrogen, together with CO_2, is produced by reacting the carbon monoxide with steam in a second reactor (a "shift reactor"). The resulting mixture of hydrogen and CO_2 can then be separated into a CO_2 gas stream, and a stream of hydrogen. If the CO_2 is stored, the hydrogen is a carbon-free energy carrier that can be combusted to generate power and/or heat. Although the initial fuel conversion steps are more elaborate and costly than in post-combustion systems, the high concentrations of CO_2 produced by the shift reactor (typically 15 to 60% by volume on a dry basis) and the high pressures often encountered in these applications are more favourable for CO_2 separation. Pre-combustion would be used at power plants that employ integrated gasification combined cycle (IGCC) technology.

Oxyfuel combustion systems use oxygen instead of air for combustion of the primary fuel to produce a flue gas that is mainly water vapour and CO_2. This results in a flue gas with high CO_2 concentrations (greater than 80% by volume). The water vapour is then removed by cooling and compressing the gas stream. Oxyfuel combustion requires the upstream separation of oxygen from air, with a purity of 95–99% oxygen assumed in most current designs. Further treatment of the flue gas may be needed to remove air pollutants and non-condensed gases (such as nitrogen) from the flue gas before the CO_2 is sent to storage. As a method of CO_2 capture in boilers, oxyfuel combustion systems are in the demonstration phase (see Table TS.1). Oxyfuel systems are also being studied in gas turbine systems, but conceptual designs for such applications are still in the research phase.

Figure TS.3 shows a schematic diagram of the main capture processes and systems. All require a step involving the separation of CO_2, H_2 or O_2 from a bulk gas stream (such as flue gas, synthesis gas, air or raw natural gas). These separation steps can be accomplished by means of physical or chemical solvents, membranes, solid sorbents, or by cryogenic separation. The choice of a specific capture technology is determined largely by the process conditions under which it must operate. Current post-combustion and pre-combustion systems for power plants could capture 85–95% of the CO_2 that is produced. Higher capture efficiencies are possible, although separation devices become considerably larger, more energy intensive and more costly. Capture and compression need roughly 10–40% more energy than the equivalent plant without capture, depending on the type of system. Due to the associated CO_2 emissions, the net amount of CO_2 captured is approximately 80–90%. Oxyfuel combustion systems are, in principle, able to capture nearly all of the CO_2 produced. However, the need for additional gas treatment systems to remove pollutants such as sulphur and nitrogen oxides lowers the level of CO_2 captured to slightly more than 90%.

As noted in Section 1, CO_2 capture is already used in several industrial applications (see Figure TS.4). The same technologies as would be used for pre-combustion capture are employed for the large-scale production of hydrogen (which is used mainly for ammonia and fertilizer manufacture, and for petroleum refinery operations). The separation of CO_2 from raw natural gas (which typically contains significant amounts of CO_2) is also practised on a large scale, using technologies similar to those used for post-combustion capture. Although commercial systems are also available for large-scale oxygen separation, oxyfuel combustion for CO_2 capture is currently in the demonstration phase. In addition, research is being conducted to achieve higher levels of system integration, increased efficiency and reduced cost for all types of capture systems.

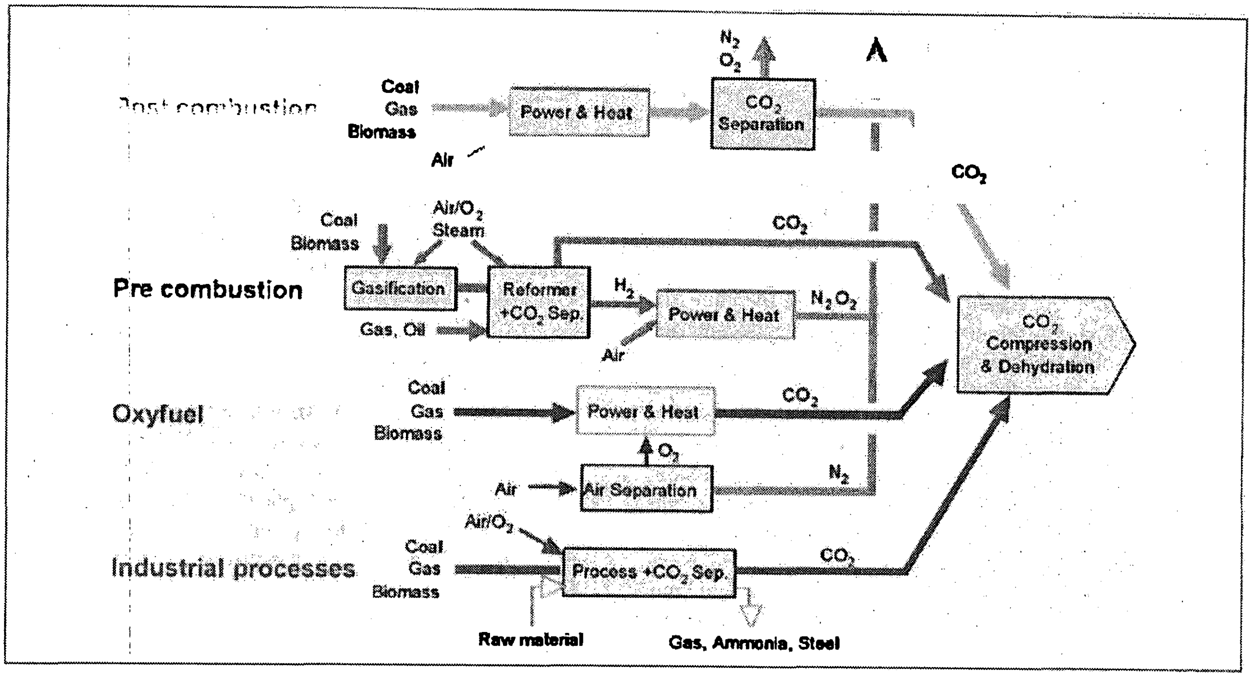

Figure TS.3. Overview of CO_2 capture processes and systems.

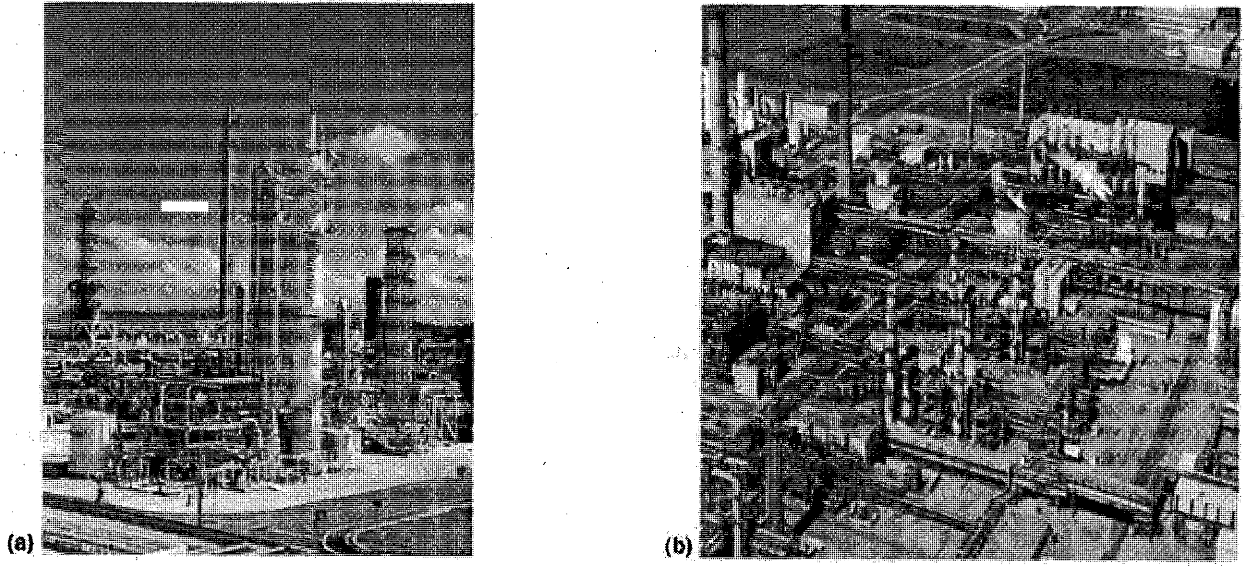

Figure TS.4. (a) CO_2 post-combustion capture at a plant in Malaysia. This plant employs a chemical absorption process to separate 0.2 $MtCO_2$ per year from the flue gas stream of a gas-fired power plant for urea production (Courtesy of Mitsubishi Heavy Industries). (b) CO_2 pre-combustion capture at a coal gasification plant in North Dakota, USA. This plant employs a physical solvent process to separate 3.3 $MtCO_2$ per year from a gas stream to produce synthetic natural gas. Part of the captured CO_2 is used for an EOR project in Canada.

CO_2 capture: risks, energy and the environment

The monitoring, risk and legal implications of CO_2 capture systems do not appear to present fundamentally new challenges, as they are all elements of regular health, safety and environmental control practices in industry. However, CO_2 capture systems require significant amounts of energy for their operation. This reduces net plant efficiency, so power plants require more fuel to generate each kilowatt-hour of electricity produced. Based on a review of the literature, the increase in fuel consumption per kWh for plants capturing 90% CO_2 using best current technology ranges from 24–40% for new supercritical PC plants, 11–22% for NGCC plants, and 14–25% for coal-based IGCC systems compared to similar plants without CCS. The increased fuel requirement results in an increase in most other environmental emissions per kWh generated relative to new state-of-the-art plants without CO_2 capture and, in the case of coal, proportionally larger amounts of solid wastes. In addition, there is an increase in the consumption of chemicals such as ammonia and limestone used by PC plants for nitrogen oxide and sulphur dioxide emissions control. Advanced plant designs that further reduce CCS energy requirements will also reduce overall environmental impacts as well as cost. Compared to many older existing plants, more efficient new or rebuilt plants with CCS may actually yield net reductions in plant-level environmental emissions.

Costs of CO_2 capture

The estimated costs of CO_2 capture at large power plants are based on engineering design studies of technologies in commercial use today (though often in different applications and/or at smaller scales than those assumed in the literature), as well as on design studies for concepts currently in the research and development (R&D) stage. Table TS.3 summarizes the results for new supercritical PC, NGCC and IGCC plants based on current technology with and without CO_2 capture. Capture systems for all three designs reduce CO_2 emissions per kWh by approximately 80–90%, taking into account the energy requirements for capture. All data for PC and IGCC plants in Table TS.3 are for bituminous coals only. The capture costs include the cost of compressing CO_2 (typically to about 11–14 MPa) but do not include the additional costs of CO_2 transport and storage (see Sections 4–7).

The cost ranges for each of the three systems reflect differences in the technical, economic and operating assumptions employed in different studies. While some differences in reported costs can be attributed to differences in the design of CO_2 capture systems, the major sources of variability are differences in the assumed design, operation and financing of the reference plant to which the capture technology is applied (factors such as plant size, location, efficiency, fuel type, fuel cost, capacity factor and cost of capital). No single set of assumptions applies to all situations or all parts of the world, so a range of costs is given.

For the studies listed in Table TS.3, CO_2 capture increases the cost of electricity production[5] by 35–70% (0.01 to 0.02 US\$/kWh) for an NGCC plant, 40–85% (0.02 to 0.03 US\$/kWh) for a supercritical PC plant, and 20–55% (0.01 to 0.02 US\$/kWh) for an IGCC plant. Overall, the electricity production costs for fossil fuel plants with capture (excluding CO_2 transport and storage costs) ranges from 0.04–0.09 US\$/kWh, as compared to 0.03–0.06 US\$/kWh for similar plants without capture. In most studies to date, NGCC systems have typically been found to have lower electricity production costs than new PC and IGCC plants (with or without capture) in the case of large base-load plants with high capacity factors (75% or more) and natural gas prices between 2.6 and 4.4 US\$ GJ^{-1} over the life of the plant. However, in the case of higher gas prices and/or lower capacity factors, NGCC plants often have higher electricity production costs than coal-based plants, with or without capture. Recent studies also found that IGCC plants were on average slightly more costly without capture and slightly less costly with capture than similarly-sized PC plants. However, the difference in cost between PC and IGCC plants with or without CO_2 capture can vary significantly according to coal type and other local factors, such as the cost of capital for each plant type. Since full-scale NGCC, PC and IGCC systems have not yet been built with CCS, the absolute or relative costs of these systems cannot be stated with a high degree of confidence at this time.

The costs of retrofitting existing power plants with CO_2 capture have not been extensively studied. A limited number of reports indicate that retrofitting an amine scrubber to an existing plant results in greater efficiency loss and higher costs than those shown in Table TS.3. Limited studies also indicate that a more cost-effective option is to combine a capture system retrofit with rebuilding the boiler and turbine to increase plant efficiency and output. For some existing plants, studies indicate that similar benefits could be achieved by repowering with an IGCC system that includes CO_2 capture technology. The feasibility and cost of all these options is highly dependent on site-specific factors, including the size, age and efficiency of the plant, and the availability of additional space.

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[5] The cost of electricity production should not be confused with the price of electricity to customers.

Table TS.3. Summary of CO_2 capture costs for new power plants based on current technology. Because these costs do not include the costs (or credits) for CO_2 transport and storage, this table should not be used to assess or compare total plant costs for different systems with capture. The full costs of CCS plants are reported in Section 8.

Performance and cost measures	New NGCC plant			New PC plant			New IGCC plant		
	Range		Rep. value	Range		Rep. value	Range		Rep. value
	Low	High		Low	High		Low	High	
Emission rate without capture (kgCO$_2$/kWh)	0.344	0.379	0.367	0.736	0.811	0.762	0.682	0.846	0.773
Emission rate with capture (kgCO$_2$/kWh)	0.040	0.066	0.052	0.092	0.145	0.112	0.065	0.152	0.108
Percentage CO$_2$ reduction per kWh (%)	83	88	86	81	88	85	81	91	86
Plant efficiency with capture, LHV basis (%)	47	50	48	30	35	33	31	40	35
Capture energy requirement (% increase input/kWh)	11	22	16	24	40	31	14	25	19
Total capital requirement without capture (US$/kW)	515	724	568	1161	1486	1286	1169	1565	1326
Total capital requirement with capture (US$/kW)	909	1261	998	1894	2578	2096	1414	2270	1825
Percent increase in capital cost with capture (%)	64	100	76	44	74	63	19	66	37
COE without capture (US$/kWh)	0.031	0.050	0.037	0.043	0.052	0.046	0.041	0.061	0.047
COE with capture only (US$/kWh)	0.043	0.072	0.054	0.062	0.086	0.073	0.054	0.079	0.062
Increase in COE with capture (US$/kWh)	0.012	0.024	0.017	0.018	0.034	0.027	0.009	0.022	0.016
Percent increase in COE with capture (%)	37	69	46	42	66	57	20	55	33
Cost of net CO$_2$ captured (US$/tCO$_2$)	37	74	53	29	51	41	13	37	23
Capture cost confidence level (see Table 3.6)	moderate			moderate			moderate		

Abbreviations: Representative value is based on the average of the values in the different studies. COE=cost of electricity production; LHV=lower heating value. See Section 3.6.1 for calculation of energy requirement for capture plants.

Notes: Ranges and representative values are based on data from Special Report Tables 3.7, 3.9 and 3.10. All PC and IGCC data are for bituminous coals only at costs of 1.0-1.5 US$ GJ^{-1} (LHV); all PC plants are supercritical units. NGCC data based on natural gas prices of 2.8-4.4 US$ GJ^{-1} (LHV basis). Cost are stated in constant US$2002. Power plant sizes range from approximately 400-800 MW without capture and 300-700 MW with capture. Capacity factors vary from 65-85% for coal plants and 50-95% for gas plants (average for each=80%). Fixed charge factors vary from 11-16%. All costs include CO$_2$ compression but not additional CO$_2$ transport and storage costs

Table TS.4 illustrates the cost of CO$_2$ capture in the production of hydrogen. Here, the cost of CO$_2$ capture is mainly due to the cost of CO$_2$ drying and compression, since CO$_2$ separation is already carried out as part of the hydrogen production process. The cost of CO$_2$ capture adds approximately 5% to 30% to the cost of the hydrogen produced.

CCS also can be applied to systems that use biomass fuels or feedstock, either alone or in combination with fossil fuels. A limited number of studies have looked at the costs of such systems combining capture, transport and storage. The capturing of 0.19 MtCO$_2$ yr^{-1} in a 24 MWe biomass IGCC plant is estimated to be about 80 US$/tCO$_2$ net captured (300 US$/tC), which corresponds to an increase in electricity production costs of about 0.08 US$/kWh. There are relatively few studies of CO$_2$ capture for other industrial processes using fossil fuels and they are typically limited to capture costs reported only as a cost per tonne of CO$_2$ captured or avoided. In general, the CO$_2$ produced in different processes varies widely in pressure and concentration (see Section 2). As a result, the cost of capture in different processes (cement and steel plants, refineries), ranges widely from about 25–115 US$/tCO$_2$ net captured. The unit cost of capture is generally lower for processes where a relatively pure CO$_2$ stream is produced (e.g. natural gas processing, hydrogen production and ammonia production), as seen for the hydrogen plants

Table TS.4. Summary of CO_2 capture costs for new hydrogen plants based on current technology

Performance and cost measures	New hydrogen plant		
	Range		Representative value
	Low	High	
Emission rate without capture ($kgCO_2\ GJ^{-1}$)	78	174	137
Emission rate with capture ($kgCO_2\ GJ^{-1}$)	7	28	17
Percent CO_2 reduction per GJ (%)	72	96	86
Plant efficiency with capture, LHV basis (%)	52	68	60
Capture energy requirement (% more input GJ^{-1})	4	22	8
Cost of hydrogen without capture (US\$ GJ^{-1})	6.5	10.0	7.8
Cost of hydrogen with capture (US\$ GJ^{-1})	7.5	13.3	9.1
Increase in H_2 cost with capture (US\$ GJ^{-1})	0.3	3.3	1.3
Percent increase in H_2 cost with capture (%)	5	33	15
Cost of net CO_2 captured (US\$/tCO_2)	2	56	15
Capture cost confidence level	moderate to high		

Notes: Ranges and representative values are based on data from Table 3.11. All costs in this table are for capture only and do not include the costs of CO_2 transport and storage. Costs are in constant US\$2002. Hydrogen plant feedstocks are natural gas (4.7-5.3 US\$ GJ^{-1}) or coal (0.9-1.3 US\$ GJ^{-1}); some plants in dataset produce electricity in addition to hydrogen. Fixed charge factors vary from 13-20%. All costs include CO_2 compression but not additional CO_2 transport and storage costs (see Section 8 for full CCS costs).

in Table TS.4, where costs vary from 2–56 US\$/tCO_2 net captured.

New or improved methods of CO_2 capture, combined with advanced power systems and industrial process designs, could reduce CO_2 capture costs and energy requirements. While costs for first-of-a-kind commercial plants often exceed initial cost estimates, the cost of subsequent plants typically declines as a result of learning-by-doing and other factors. Although there is considerable uncertainty about the magnitude and timing of future cost reductions, the literature suggests that, provided R&D efforts are sustained, improvements to commercial technologies can reduce current CO_2 capture costs by at least 20–30% over approximately the next ten years, while new technologies under development could achieve more substantial cost reductions. Future cost reductions will depend on the deployment and adoption of commercial technologies in the marketplace as well as sustained R&D.

4. Transport of CO_2

Except when plants are located directly above a geological storage site, captured CO_2 must be transported from the point of capture to a storage site. This section reviews the principal methods of CO_2 transport and assesses the health, safety and environment aspects, and costs.

Methods of CO_2 transport

Pipelines today operate as a mature market technology and are the most common method for transporting CO_2. Gaseous CO_2 is typically compressed to a pressure above 8 MPa in order to avoid two-phase flow regimes and increase the density of the CO_2, thereby making it easier and less costly to transport. CO_2 also can be transported as a liquid in ships, road or rail tankers that carry CO_2 in insulated tanks at a temperature well below ambient, and at much lower pressures.

The first long-distance CO_2 pipeline came into operation in the early 1970s. In the United States, over 2,500 km of pipeline transports more than 40 $MtCO_2$ per year from natural and anthropogenic sources, mainly to sites in Texas, where the CO_2 is used for EOR.These pipelines operate in the 'dense phase' mode (in which there is a continuous progression from gas to liquid, without a distinct phase change), and at ambient temperature and high pressure. In most of these pipelines, the flow is driven by compressors at the upstream end, although some pipelines have intermediate (booster) compressor stations.

In some situations or locations, transport of CO_2 by ship may be economically more attractive, particularly when the CO_2 has to be moved over large distances or overseas. Liquefied petroleum gases (LPG, principally propane and butane) are transported on a large commercial scale by marine tankers. CO_2 can be transported by ship in much the same way (typically at 0.7 MPa pressure), but this currently takes place on a small scale because of limited demand. The properties of liquefied CO_2 are similar to those of LPG, and the technology could be scaled up to large CO_2 carriers if a demand for such systems were to materialize.

Road and rail tankers also are technically feasible options. These systems transport CO_2 at a temperature of -20°C and at 2 MPa pressure. However, they are uneconomical compared to pipelines and ships, except on a very small scale, and are unlikely to be relevant to large-scale CCS.

Environment, safety and risk aspects

Just as there are standards for natural gas admitted to pipelines, so minimum standards for 'pipeline quality' CO_2 should emerge as the CO_2 pipeline infrastructure develops further. Current standards, developed largely in the context of EOR applications, are not necessarily identical to what would be required for CCS. A low-nitrogen content is important for EOR, but would not be so significant for CCS. However, a CO_2 pipeline through populated areas might need a lower specified maximum H_2S content. Pipeline transport of CO_2 through populated areas also requires detailed route selection, over-pressure protection, leak detection and other design factors. However, no major obstacles to pipeline design for CCS are foreseen.

CO_2 could leak to the atmosphere during transport, although leakage losses from pipelines are very small. Dry (moisture-free) CO_2 is not corrosive to the carbon-manganese steels customarily used for pipelines, even if the CO_2 contains contaminants such as oxygen, hydrogen sulphide, and sulphur or nitrogen oxides. Moisture-laden CO_2, on the other hand, is highly corrosive, so a CO_2 pipeline in this case would have to be made from a corrosion-resistant alloy, or be internally clad with an alloy or a continuous polymer coating. Some pipelines are made from corrosion-resistant alloys, although the cost of materials is several times larger than carbon-manganese steels. For ships, the total loss to the atmosphere is between 3 and 4% per 1000 km, counting both boil-off and the exhaust from ship engines. Boil-off could be reduced by capture and liquefaction, and recapture would reduce the loss to 1 to 2% per 1000 km.

Accidents can also occur. In the case of existing CO_2 pipelines, which are mostly in areas of low population density, there have been fewer than one reported incident per year (0.0003 per km-year) and no injuries or fatalities. This is consistent with experience with hydrocarbon pipelines, and the impact would probably not be more severe than for natural gas accidents. In marine transportation, hydrocarbon gas tankers are potentially dangerous, but the recognized hazard has led to standards for design, construction and operation, and serious incidents are rare.

Cost of CO_2 transport

Costs have been estimated for both pipeline and marine transportation of CO_2. In every case the costs depend strongly on the distance and the quantity transported. In the case of pipelines, the costs depend on whether the pipeline is onshore or offshore, whether the area is heavily congested, and whether there are mountains, large rivers, or frozen ground on the route. All these factors could double the cost per unit length, with even larger increases for pipelines in populated areas. Any additional costs for recompression (booster pump stations) that may be needed for longer pipelines would be counted as part of transport costs. Such costs are relatively small and not included in the estimates presented here.

Figure TS.5 shows the cost of pipeline transport for a nominal distance of 250 km. This is typically 1–8 US\$/tCO_2 (4–30 US\$/tC). The figure also shows how pipeline cost depends on the CO_2 mass flow rate. Steel cost accounts for a significant fraction of the cost of a pipeline, so fluctuations in such cost (such as the doubling in the years from 2003 to 2005) could affect overall pipeline economics.

In ship transport, the tanker volume and the characteristics of the loading and unloading systems are some of the key factors determining the overall transport cost.

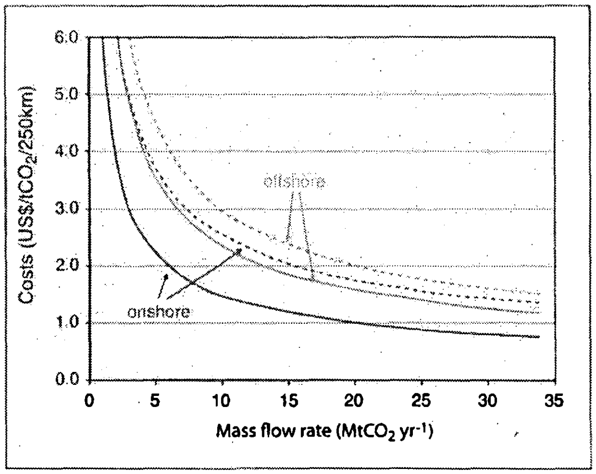

Figure TS.5. Transport costs for onshore pipelines and offshore pipelines, in US\$ per tCO_2 per 250 km as a function of the CO_2 mass flow rate. The graph shows high estimates (dotted lines) and low estimates (solid lines).

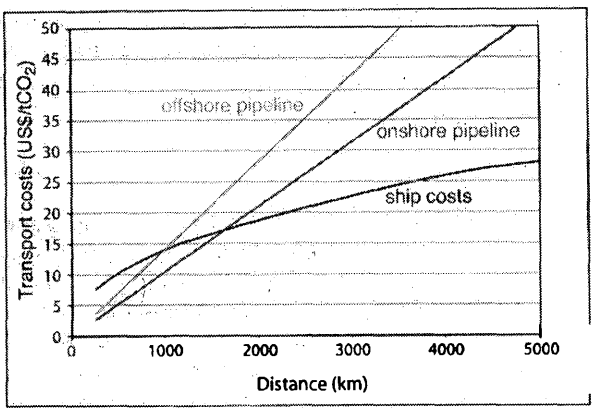

Figure TS.6. Costs, plotted as US$/t$CO_2$ transported against distance, for onshore pipelines, offshore pipelines and ship transport. Pipeline costs are given for a mass flow of 6 MtCO_2 yr^{-1}. Ship costs include intermediate storage facilities, harbour fees, fuel costs, and loading and unloading activities. Costs include also additional costs for liquefaction compared to compression.

The costs associated with CO_2 compression and liquefaction are accounted for in the capture costs presented earlier. Figure TS.6 compares pipeline and marine transportation costs, and shows the break-even distance. If the marine option is available, it is typically cheaper than pipelines for distances greater than approximately 1000 km and for amounts smaller than a few million tonnes of CO_2 per year. In ocean storage the most suitable transport system depends on the injection method: from a stationary floating vessel, a moving ship, or a pipeline from shore.

5. Geological storage

This section examines three types of geological formations that have received extensive consideration for the geological storage of CO_2: oil and gas reservoirs, deep saline formations and unminable coal beds (Figure TS.7). In each case, geological storage of CO_2 is accomplished by injecting it in dense form into a rock formation below the earth's surface. Porous rock formations that hold or (as in the case of depleted oil and gas reservoirs) have previously held fluids, such as natural gas, oil or brines, are potential candidates for CO_2 storage. Suitable storage formations can occur in both onshore and offshore sedimentary basins (natural large-scale depressions in the earth's crust that are filled with sediments). Coal beds also may be used for storage of CO_2 (see Figure TS.7) where it is unlikely that the coal will later be mined and provided that permeability is sufficient. The option of storing CO_2 in coal beds and enhancing methane production is still in the demonstration phase (see Table TS.1).

Existing CO_2 storage projects

Geological storage of CO_2 is ongoing in three industrial-scale projects (projects in the order of 1 MtCO_2 yr^{-1} or more): the Sleipner project in the North Sea, the Weyburn project in Canada and the In Salah project in Algeria. About 3–4 MtCO_2 that would otherwise be released to the atmosphere is captured and stored annually in geological formations. Additional projects are listed in Table TS.5.

In addition to the CCS projects currently in place, 30 MtCO_2 is injected annually for EOR, mostly in Texas, USA, where EOR commenced in the early 1970s. Most of this CO_2 is obtained from natural CO_2 reservoirs found in western regions of the US, with some coming from anthropogenic sources such as natural gas processing. Much of the CO_2 injected for EOR is produced with the oil, from which it is separated and then reinjected. At the end of the oil recovery, the CO_2 can be retained for the purpose of climate change mitigation, rather than vented to the atmosphere. This is planned for the Weyburn project.

Storage technology and mechanisms

The injection of CO_2 in deep geological formations involves many of the same technologies that have been developed in the oil and gas exploration and production industry. Well-drilling technology, injection technology, computer simulation of storage reservoir dynamics and monitoring methods from existing applications are being developed further for design and operation of geological storage. Other underground injection practices also provide relevant operational experience. In particular, natural gas storage, the deep injection of liquid wastes, and acid gas disposal (mixtures of CO_2 and H_2S) have been conducted in Canada and the U.S. since 1990, also at the megatonne scale.

CO_2 storage in hydrocarbon reservoirs or deep saline formations is generally expected to take place at depths below 800 m, where the ambient pressures and temperatures will usually result in CO_2 being in a liquid or supercritical state. Under these conditions, the density of CO_2 will range from 50 to 80% of the density of water. This is close to the density of some crude oils, resulting in buoyant forces that tend to drive CO_2 upwards. Consequently, a well-sealed cap rock over the selected storage reservoir is important to ensure that CO_2 remains trapped underground. When injected underground, the CO_2 compresses and fills the pore space by partially displacing the fluids that are already present (the 'in situ fluids'). In oil and gas reservoirs, the displacement of in situ fluids by injected CO_2 can result in most of the pore volume being available for CO_2 storage. In saline formations, estimates of potential storage volume are lower, ranging from as low as a few percent to over 30% of the total rock volume.

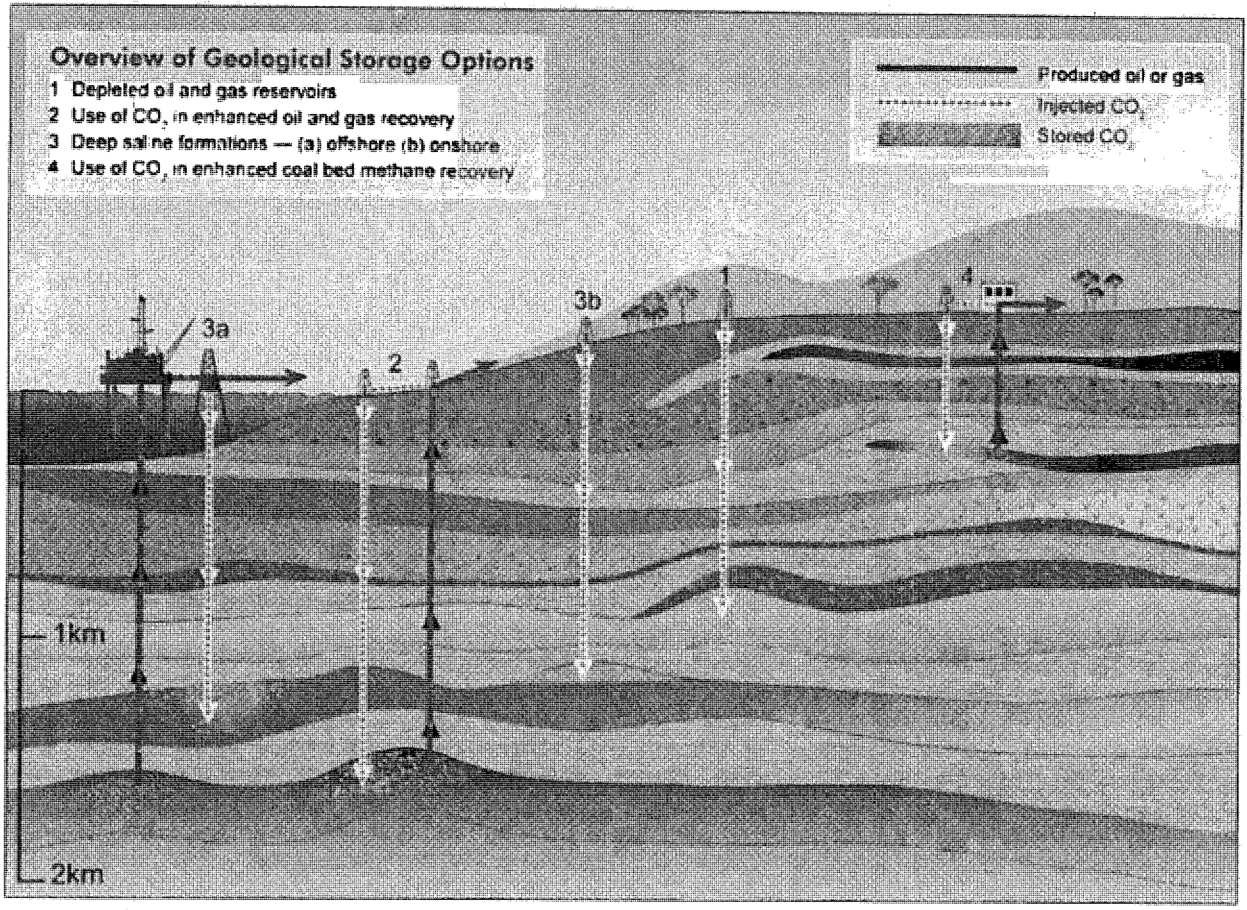

Figure TS.7. Methods for storing CO_2 in deep underground geological formations. Two methods may be combined with the recovery of hydrocarbons: EOR (2) and ECBM (4). See text for explanation of these methods (Courtesy CO2CRC).

Once injected into the storage formation, the fraction retained depends on a combination of physical and geochemical trapping mechanisms. Physical trapping to block upward migration of CO_2 is provided by a layer of shale and clay rock above the storage formation. This impermeable layer is known as the "cap rock". Additional physical trapping can be provided by capillary forces that retain CO_2 in the pore spaces of the formation. In many cases, however, one or more sides of the formation remain open, allowing for lateral migration of CO_2 beneath the cap rock. In these cases, additional mechanisms are important for the long-term entrapment of the injected CO_2.

The mechanism known as geochemical trapping occurs as the CO_2 reacts with the in situ fluids and host rock. First, CO_2 dissolves in the in situ water. Once this occurs (over time scales of hundreds of years to thousands of years), the CO_2-laden water becomes more dense and therefore sinks down into the formation (rather than rising toward the surface). Next, chemical reactions between the dissolved CO_2 and rock minerals form ionic species, so that a fraction of the injected CO_2 will be converted to solid carbonate minerals over millions of years.

Yet another type of trapping occurs when CO_2 is preferentially adsorbed onto coal or organic-rich shales replacing gases such as methane. In these cases, CO_2 will remain trapped as long as pressures and temperatures remain stable. These processes would normally take place at shallower depths than CO_2 storage in hydrocarbon reservoirs and saline formations.

Geographical distribution and capacity of storage sites

As shown earlier in Section 2 (Figure TS.2b), regions with sedimentary basins that are potentially suitable for CO_2 storage exist around the globe, both onshore and offshore. This report focuses on oil and gas reservoirs, deep saline

Table TS.5. Sites where CO_2 storage has been done, is currently in progress or is planned, varying from small pilots to large-scale commercial applications.

Project name	Country	Injection start (year)	Approximate average daily injection rate (tCO_2 day^{-1})	Total (planned) storage (tCO_2)	Storage reservoir type
Weyburn	Canada	2000	3,000-5,000	20,000,000	EOR
In Salah	Algeria	2004	3,000-4,000	17,000,000	Gas field
Sleipner	Norway	1996	3,000	20,000,000	Saline formation
K12B	Netherlands	2004	100 (1,000 planned for 2006+)	8,000,000	Enhanced gas recovery
Frio	U.S.A	2004	177	1600	Saline formation
Fenn Big Valley	Canada	1998	50	200	ECBM
Qinshui Basin	China	2003	30	150	ECBM
Yubari	Japan	2004	10	200	ECBM
Recopol	Poland	2003	1	10	ECBM
Gorgon (planned)	Australia	~2009	10,000	unknown	Saline formation
Snøhvit (planned)	Norway	2006	2,000	unknown	Saline formation

formations and unminable coal beds. Other possible geological formations or structures (such as basalts, oil or gas shales, salt caverns and abandoned mines) represent niche opportunities, or have been insufficiently studied at this time to assess their potential.

The estimates of the technical potential[6] for different geological storage options are summarized in Table TS.6. The estimates and levels of confidence are based on an assessment of the literature, both of regional bottom-up, and global top-down estimates. No probabilistic approach to assessing capacity estimates exists in the literature, and this would be required to quantify levels of uncertainty reliably. Overall estimates, particularly of the upper limit of the potential, vary widely and involve a high degree of uncertainty, reflecting conflicting methodologies in the literature and the fact that our knowledge of saline formations is quite limited in most parts of the world. For oil and gas reservoirs, better estimates are available which are based on the replacement of hydrocarbon volumes with CO_2 volumes. It should be noted that, with the exception of EOR, these reservoirs will not be available for CO_2 storage until the hydrocarbons are depleted, and that pressure changes and geomechanical effects due to hydrocarbon production in the reservoir may reduce actual capacity.

Another way of looking at storage potential, however, is to ask whether it is likely to be adequate for the amounts of CO_2 that would need to be avoided using CCS under different greenhouse gas stabilization scenarios and assumptions about the deployment of other mitigation options. As discussed later in Section 8, the estimated range of economic potential[7] for CCS over the next century is roughly 200 to 2,000 $GtCO_2$. The lower limits in Table TS.6 suggest that, worldwide, it is virtually certain[8] that there is 200 $GtCO_2$ of geological storage capacity, and likely[9] that there is at least about 2,000 $GtCO_2$.

Site selection criteria and methods

Site characterization, selection and performance prediction are crucial for successful geological storage. Before selecting a site, the geological setting must be characterized to determine if the overlying cap rock will provide an effective seal, if there is a sufficiently voluminous and permeable storage formation, and whether any abandoned or active wells will compromise the integrity of the seal.

Techniques developed for the exploration of oil and gas reservoirs, natural gas storage sites and liquid waste disposal sites are suitable for characterizing geological storage sites for CO_2. Examples include seismic imaging, pumping tests for evaluating storage formations and seals, and cement integrity logs. Computer programmes that model underground CO_2 movement are used to support site characterization and selection activities. These programmes were initially developed for applications such as oil and

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[6] Technical potential is the amount by which it is possible to reduce greenhouse gas emissions by implementing a technology or practice that already has been demonstrated.

[7] Economic potential is the amount of greenhouse gas emissions reductions from a specific option that could be achieved cost-effectively, given prevailing circumstances (the price of CO_2 reductions and costs of other options).

[8] "Virtually certain" is a probability of 99% or more.

[9] "Likely" is a probability of 66 to 90%.

Table TS.6. Storage capacity for several geological storage options. The storage capacity includes storage options that are not economical.

Reservoir type	**Lower estimate of storage capacity ($GtCO_2$)**	**Upper estimate of storage capacity ($GtCO_2$)**
Oil and gas fields	675[a]	900[a]
Unminable coal seams (ECBM)	3-15	200
Deep saline formations	1,000	Uncertain, but possibly 10^4

[a] These numbers would increase by 25% if 'undiscovered' oil and gas fields were included in this assessment.

gas reservoir engineering and groundwater resources investigations. Although they include many of the physical, chemical and geomechanical processes needed to predict both short-term and long-term performance of CO_2 storage, more experience is needed to establish confidence in their effectiveness in predicting long-term performance when adapted for CO_2 storage. Moreover, the availability of good site characterization data is critical for the reliability of models.

Risk assessment and environmental impact

The risks due to leakage from storage of CO_2 in geological reservoirs fall into two broad categories: global risks and local risks. Global risks involve the release of CO_2 that may contribute significantly to climate change if some fraction leaks from the storage formation to the atmosphere. In addition, if CO_2 leaks out of a storage formation, local hazards may exist for humans, ecosystems and groundwater. These are the local risks.

With regard to global risks, based on observations and analysis of current CO_2 storage sites, natural systems, engineering systems and models, the fraction retained in appropriately selected and managed reservoirs is very likely[10] to exceed 99% over 100 years, and is likely to exceed 99% over 1000 years. Similar fractions retained are likely for even longer periods of time, as the risk of leakage is expected to decrease over time as other mechanisms provide additional trapping. The question of whether these fractions retained would be sufficient to make impermanent storage valuable for climate change mitigation is discussed in Section 8.

With regard to local risks, there are two types of scenarios in which leakage may occur. In the first case, injection well failures or leakage up abandoned wells could create a sudden and rapid release of CO_2. This type of release is likely to be detected quickly and stopped using techniques that are available today for containing well blow-outs. Hazards associated with this type of release primarily affect workers in the vicinity of the release at the time it occurs, or those called in to control the blow-out. A concentration of CO_2 greater than 7–10% in air would cause immediate dangers to human life and health. Containing these kinds of releases may take hours to days and the overall amount of CO_2 released is likely to be very small compared to the total amount injected. These types of hazards are managed effectively on a regular basis in the oil and gas industry using engineering and administrative controls.

In the second scenario, leakage could occur through undetected faults, fractures or through leaking wells where the release to the surface is more gradual and diffuse. In this case, hazards primarily affect drinking-water aquifers and ecosystems where CO_2 accumulates in the zone between the surface and the top of the water table. Groundwater can be affected both by CO_2 leaking directly into an aquifer and by brines that enter the aquifer as a result of being displaced by CO_2 during the injection process. There may also be acidification of soils and displacement of oxygen in soils in this scenario. Additionally, if leakage to the atmosphere were to occur in low-lying areas with little wind, or in sumps and basements overlying these diffuse leaks, humans and animals would be harmed if a leak were to go undetected. Humans would be less affected by leakage from offshore storage locations than from onshore storage locations. Leakage routes can be identified by several techniques and by characterization of the reservoir. Figure TS.8 shows some of the potential leakage paths for a saline formation. When the potential leakage routes are known, the monitoring and remediation strategy can be adapted to address the potential leakage.

Careful storage system design and siting, together with methods for early detection of leakage (preferably long before CO_2 reaches the land surface), are effective ways of reducing hazards associated with diffuse leakage. The available monitoring methods are promising, but more experience is needed to establish detection levels and resolution. Once leakages are detected, some remediation techniques are available to stop or control them. Depending on the type of leakage, these techniques could involve standard well repair techniques, or the extraction of CO_2 by intercepting its leak into a shallow groundwater aquifer (see Figure TS.8).

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[10] "Very likely" is a probability of 90 to 99%.

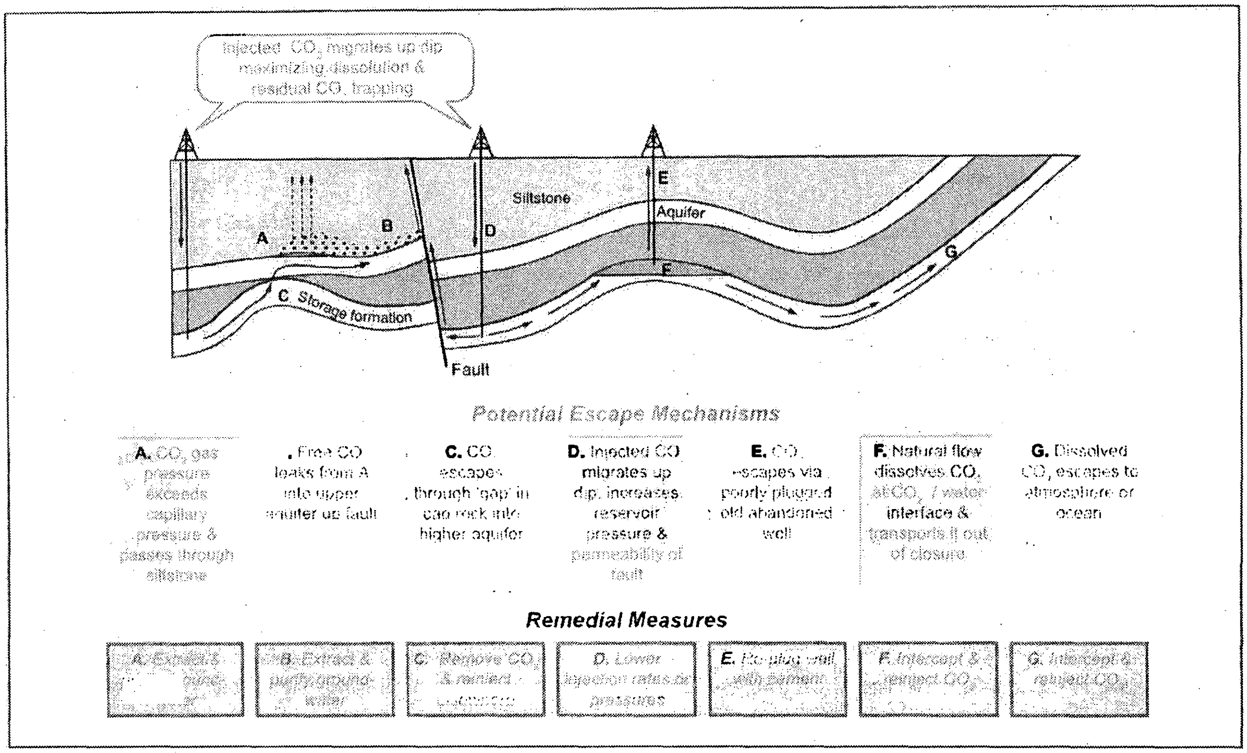

Figure TS.8. Potential leakage routes and remediation techniques for CO$_2$ injected into saline formations. The remediation technique would depend on the potential leakage routes identified in a reservoir (Courtesy CO2CRC).

Techniques to remove CO$_2$ from soils and groundwater are also available, but they are likely to be costly. Experience will be needed to demonstrate the effectiveness, and ascertain the costs, of these techniques for use in CO$_2$ storage.

Monitoring and verification

Monitoring is a very important part of the overall risk management strategy for geological storage projects. Standard procedures or protocols have not been developed yet but they are expected to evolve as technology improves, depending on local risks and regulations. However, it is expected that some parameters such as injection rate and injection well pressure will be measured routinely. Repeated seismic surveys have been shown to be useful for tracking the underground migration of CO$_2$. Newer techniques such as gravity and electrical measurements may also be useful. The sampling of groundwater and the soil between the surface and water table may be useful for directly detecting CO$_2$ leakage. CO$_2$ sensors with alarms can be located at the injection wells for ensuring worker safety and to detect leakage. Surface-based techniques may also be used for detecting and quantifying surface releases. High-quality baseline data improve the reliability and resolution of all measurements and will be essential for detecting small rates of leakage.

Since all of these monitoring techniques have been adapted from other applications, they need to be tested and assessed with regard to reliability, resolution and sensitivity in the context of geological storage. All of the existing industrial-scale projects and pilot projects have programmes to develop and test these and other monitoring techniques. Methods also may be necessary or desirable to monitor the amount of CO$_2$ stored underground in the context of emission reporting and monitoring requirements in the UNFCCC (see Section 9). Given the long-term nature of CO$_2$ storage, site monitoring may be required for very long periods.

Legal issues

At present, few countries have specifically developed legal and regulatory frameworks for onshore CO$_2$ storage. Relevant legislation include petroleum-related legislation, drinking-water legislation and mining regulations. In many cases, there are laws applying to some, if not most, of the issues related to CO$_2$ storage. Specifically, long-term liability issues, such as global issues associated with the leakage of CO_2 to the atmosphere, as well as local concerns about environmental impact, have not yet been addressed. Monitoring and verification regimes and risks of leakage may play an important role in determining liability, and vice-versa. There are also considerations such as the longevity of institutions, ongoing monitoring and transferability of institutional knowledge. The long-term perspective is essential to a legal framework for CCS as storage times extend over many generations as does the climate change problem. In some countries, notably the US, the property rights of all those affected must be considered in legal terms as pore space is owned by surface property owners.

According to the general principles of customary international law, States can exercise their sovereignty in their territories and could therefore engage in activities such as the storage of CO_2 (both geological and ocean) in those areas under their jurisdiction. However, if storage has a transboundary impact, States have the responsibility to ensure that activities within their jurisdiction or control do not cause damage to the environment of other States or of areas beyond the limits of national jurisdiction.

Currently, there are several treaties (notably the UN Convention on the Law of the Sea, and the London[11] and OSPAR[12] Conventions) that could apply to the offshore injection of CO_2 into marine environments (both into the ocean and the geological sub-seabed). All these treaties have been drafted without specific consideration of CO_2 storage. An assessment undertaken by the Jurists and Linguists Group to the OSPAR Convention (relating to the northeast Atlantic region), for example, found that, depending on the method and purpose of injection, CO_2 injection into the geological sub-seabed and the ocean could be compatible with the treaty in some cases, such as when the CO_2 is transported via a pipeline from land. A similar assessment is now being conducted by Parties to the London Convention. Furthermore, papers by legal commentators have concluded that CO_2 captured from an oil or natural gas extraction operation and stored offshore in a geological formation (like the Sleipner operation) would not be considered 'dumping' under, and would not therefore be prohibited by, the London Convention.

Public perception

Assessing public perception of CCS is challenging because of the relatively technical and "remote" nature of this issue at the present time. Results of the very few studies conducted to date about the public perception of CCS indicate that the public is generally not well informed about CCS. If information is given alongside information about other climate change mitigation options, the handful of studies carried out so far indicate that CCS is generally regarded as less favourable than other options, such as improvements in energy efficiency and the use of non-fossil energy sources. Acceptance of CCS, where it occurs, is characterized as "reluctant" rather than "enthusiastic". In some cases, this reflects the perception that CCS might be required because of a failure to reduce CO_2 emissions in other ways. There are indications that geological storage could be viewed favourably if it is adopted in conjunction with more desirable measures. Although public perception is likely to change in the future, the limited research to date indicates that at least two conditions may have to be met before CO_2 capture and storage is considered by the public as a credible technology, alongside other better known options: (1) anthropogenic global climate change has to be regarded as a relatively serious problem; (2) there must be acceptance of the need for large reductions in CO_2 emissions to reduce the threat of global climate change.

Cost of geological storage

The technologies and equipment used for geological storage are widely used in the oil and gas industries so cost estimates for this option have a relatively high degree of confidence for storage capacity in the lower range of technical potential. However, there is a significant range and variability of costs due to site-specific factors such as onshore versus offshore, reservoir depth and geological characteristics of the storage formation (e.g., permeability and formation thickness).

Representative estimates of the cost for storage in saline formations and depleted oil and gas fields are typically between 0.5–8 US\$/tCO_2 injected. Monitoring costs of 0.1–0.3 US\$/tCO_2 are additional. The lowest storage costs are for onshore, shallow, high permeability reservoirs, and/or storage sites where wells and infrastructure from existing oil and gas fields may be re-used.

When storage is combined with EOR, ECBM or (potentially) Enhanced Gas Recovery (EGR), the economic value of CO_2 can reduce the total cost of CCS. Based on data and oil prices prior to 2003, enhanced oil production for onshore EOR with CO_2 storage could yield net benefits of 10–16 US\$/tCO_2 (37–59 US\$/tC) (including the costs of geological storage). For EGR and ECBM, which are still under development, there is no reliable cost information based on actual experience. In all cases, however, the economic benefit of enhanced production

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[11] Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (1972), and its London Protocol (1996), which has not yet entered into force.

[12] Convention for the Protection of the Marine Environment of the North-East Atlantic, which was adopted in Paris (1992). OSPAR is an abbreviation of Oslo-Paris.

depends strongly on oil and gas prices. In this regard, the literature basis for this report does not take into account the rise in world oil and gas prices since 2003 and assumes oil prices of 15–20 US$ per barrel. Should higher prices be sustained over the life of a CCS project, the economic value of CO_2 could be higher than that reported here.

6. Ocean storage

A potential CO_2 storage option is to inject captured CO_2 directly into the deep ocean (at depths greater than 1,000 m), where most of it would be isolated from the atmosphere for centuries. This can be achieved by transporting CO_2 via pipelines or ships to an ocean storage site, where it is injected into the water column of the ocean or at the sea floor. The dissolved and dispersed CO_2 would subsequently become part of the global carbon cycle. Figure TS.9 shows some of the main methods that could be employed. Ocean storage has not yet been deployed or demonstrated at a pilot scale, and is still in the research phase. However, there have been small-scale field experiments and 25 years of theoretical, laboratory and modelling studies of intentional ocean storage of CO_2.

Storage mechanisms and technology

Oceans cover over 70% of the earth's surface and their average depth is 3,800 m. Because carbon dioxide is soluble in water, there are natural exchanges of CO_2 between the atmosphere and waters at the ocean surface that occur until equilibrium is reached. If the atmospheric concentration of CO_2 increases, the ocean gradually takes up additional CO_2. In this way, the oceans have taken up about 500 $GtCO_2$ (140 GtC) of the total 1,300 $GtCO_2$ (350 GtC) of anthropogenic emissions released to the atmosphere over the past 200 years. As a result of the increased atmospheric CO_2 concentrations from human activities relative to pre-industrial levels, the oceans are currently taking up CO_2 at a rate of about 7 $GtCO_2$ yr^{-1} (2 GtC yr^{-1}).

Most of this carbon dioxide now resides in the upper ocean and thus far has resulted in a decrease in *p*H of about 0.1 at the ocean surface because of the acidic nature of CO_2 in water. To date, however, there has been virtually no change in *p*H in the deep ocean. Models predict that over the next several centuries the oceans will eventually take up most of the CO_2 released to the atmosphere as CO_2 is dissolved at the ocean surface and subsequently mixed with deep ocean waters.

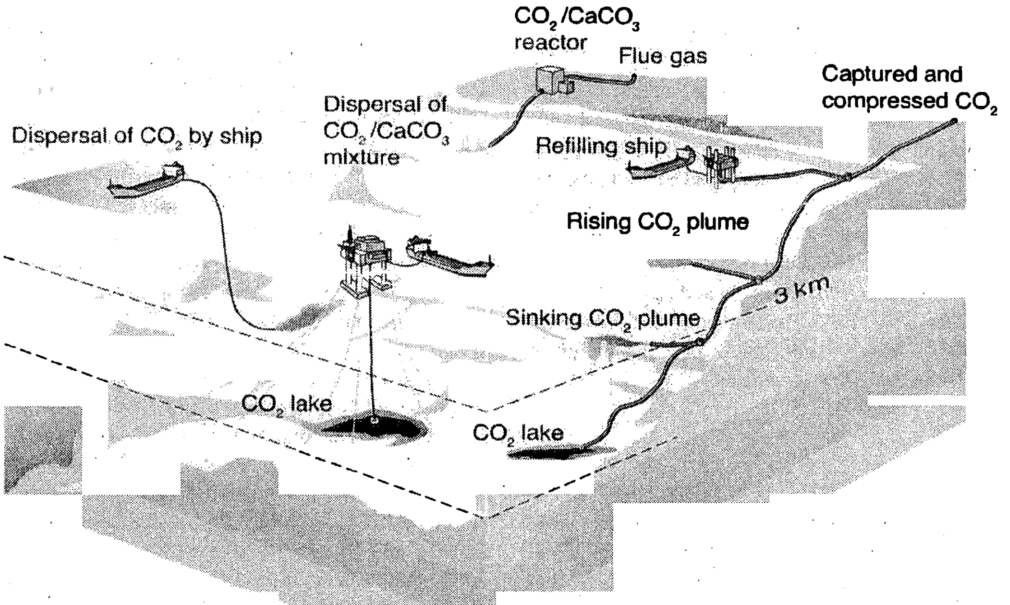

Figure TS.9. Methods of ocean storage.

There is no practical physical limit to the amount of anthropogenic CO_2 that could be stored in the ocean. However, on a millennial time scale, the amount stored will depend on oceanic equilibration with the atmosphere. Stabilizing atmospheric CO_2 concentrations between 350 ppmv and 1000 ppmv would imply that between 2,000 and 12,000 $GtCO_2$ would eventually reside in the ocean if there is no intentional CO_2 injection. This range therefore represents the upper limit for the capacity of the ocean to store CO_2 through active injection. The capacity would also be affected by environmental factors, such as a maximum allowable *p*H change.

Analysis of ocean observations and models both indicate that injected CO_2 will be isolated from the atmosphere for at least several hundreds of years, and that the fraction retained tends to be higher with deeper injection (see Table TS.7). Ideas for increasing the fraction retained include forming solid CO_2 hydrates and/or liquid CO_2 lakes on the sea floor, and dissolving alkaline minerals such as limestone to neutralize the acidic CO_2. Dissolving mineral carbonates, if practical, could extend the storage time scale to roughly 10,000 years, while minimizing changes in ocean *p*H and CO_2 partial pressure. However, large amounts of limestone and energy for materials handling would be required for this approach (roughly the same order of magnitude as the amounts per tonne of CO_2 injected that are needed for mineral carbonation; see Section 7).

Ecological and environmental impacts and risks

The injection of a few $GtCO_2$ would produce a measurable change in ocean chemistry in the region of injection, whereas the injection of hundreds of $GtCO_2$ would produce larger changes in the region of injection and eventually produce measurable changes over the entire ocean volume. Model simulations that assume a release from seven locations at 3,000 m depth and ocean storage providing 10% of the mitigation effort for stabilization at 550 ppmv CO_2 projected acidity changes (*p*H changes) of more than 0.4 over approximately 1% of the ocean volume. By comparison, in a 550 ppmv stabilization case without ocean storage, a *p*H change of more than 0.25 at the ocean surface was estimated due to equilibration with the elevated CO_2 concentrations in the atmosphere. In either case, a *p*H change of 0.2 to 0.4 is significantly greater than pre-industrial variations in ocean acidity. Over centuries, ocean mixing will result in the loss of isolation of injected CO_2. As more CO_2 reaches the ocean surface waters, releases into the atmosphere would occur gradually from large regions of the ocean. There are no known mechanisms for sudden or catastrophic release of injected CO_2 from the ocean into the atmosphere.

Experiments show that adding CO_2 can harm marine organisms. Effects of elevated CO_2 levels have mostly been studied on time scales up to several months in individual organisms that live near the ocean surface. Observed phenomena include reduced rates of calcification, reproduction, growth, circulatory oxygen supply and mobility, as well as increased mortality over time. In some organisms these effects are seen in response to small additions of CO_2. Immediate mortality is expected close to injection points or CO_2 lakes. The chronic effects of direct CO_2 injection into the ocean on ocean organisms or ecosystems over large ocean areas and long time scales have not yet been studied.

No controlled ecosystem experiments have been performed in the deep ocean, so only a preliminary assessment of potential ecosystem effects can be given. It is expected that ecosystem consequences will increase with increasing CO_2 concentrations and decreasing *p*H, but the nature of such consequences is currently not understood, and no environmental criteria have as yet been identified to avoid adverse effects. At present, it is also unclear how or whether species and ecosystems would adapt to the sustained chemical changes.

Costs of ocean storage

Although there is no experience with ocean storage, some attempts have been made to estimate the costs of CO_2 storage projects that release CO_2 on the sea floor or in the deep ocean. The costs of CO_2 capture and transport to the shoreline (e.g

Table TS.7. Fraction of CO_2 retained for ocean storage as simulated by seven ocean models for 100 years of continuous injection at three different depths starting in the year 2000.

	Injection depth		
Year	**800 m**	**1500 m**	**3000 m**
2100	0.78 ± 0.06	0.91 ± 0.05	0.99 ± 0.01
2200	0.50 ± 0.06	0.74 ± 0.07	0.94 ± 0.06
2300	0.36 ± 0.06	0.60 ± 0.08	0.87 ± 0.10
2400	0.28 ± 0.07	0.49 ± 0.09	0.79 ± 0.12
2500	0.23 ± 0.07	0.42 ± 0.09	0.71 ± 0.14

Table TS.8. Costs for ocean storage at depths deeper than 3,000 m.

Ocean storage method	**Costs (US$/tCO$_2$ net injected)**	
	100 km offshore	**500 km offshore**
Fixed pipeline	6	31
Moving ship/platform[a]	12-14	13-16

[a] The costs for the moving ship option are for injection depths of 2,000-2,500 m.

via pipelines) are not included in the cost of ocean storage. However, the costs of offshore pipelines or ships, plus any additional energy costs, are included in the ocean storage cost. The costs of ocean storage are summarized in Table TS.8. These numbers indicate that, for short distances, the fixed pipeline option would be cheaper. For larger distances, either the moving ship or the transport by ship to a platform with subsequent injection would be more attractive.

Legal aspects and public perception

The global and regional treaties on the law of the sea and marine environment, such as the OSPAR and the London Convention discussed earlier in Section 5 for geological storage sites, also affect ocean storage, as they concern the 'maritime area'. Both Conventions distinguish between the storage method employed and the purpose of storage to determine the legal status of ocean storage of CO$_2$. As yet, however, no decision has been made about the legal status of intentional ocean storage.

The very small number of public perception studies that have looked at the ocean storage of CO$_2$ indicate that there is very little public awareness or knowledge of this subject. In the few studies conducted thus far, however, the public has expressed greater reservations about ocean storage than geological storage. These studies also indicate that the perception of ocean storage changed when more information was provided; in one study this led to increased acceptance of ocean storage, while in another study it led to less acceptance. The literature also notes that 'significant opposition' developed around a proposed CO$_2$ release experiment in the Pacific Ocean.

7. Mineral carbonation and industrial uses

This section deals with two rather different options for CO$_2$ storage. The first is mineral carbonation, which involves converting CO$_2$ to solid inorganic carbonates using chemical reactions. The second option is the industrial use of CO$_2$, either directly or as feedstock for production of various carbon-containing chemicals.

Mineral carbonation: technology, impacts and costs

Mineral carbonation refers to the fixation of CO$_2$ using alkaline and alkaline-earth oxides, such as magnesium oxide (MgO) and calcium oxide (CaO), which are present in naturally occurring silicate rocks such as serpentine and olivine. Chemical reactions between these materials and CO$_2$ produces compounds such as magnesium carbonate (MgCO$_3$) and calcium carbonate (CaCO$_3$, commonly known as limestone). The quantity of metal oxides in the silicate rocks that can be found in the earth's crust exceeds the amounts needed to fix all the CO$_2$ that would be produced by the combustion of all available fossil fuel reserves. These oxides are also present in small quantities in some industrial wastes, such as stainless steel slags and ashes. Mineral carbonation produces silica and carbonates that are stable over long time scales and can therefore be disposed of in areas such as silicate mines, or re-used for construction purposes (see Figure TS.10), although such re-use is likely to be small relative to the amounts produced. After carbonation, CO$_2$ would not be released to the atmosphere. As a consequence, there would be little need to monitor the disposal sites and the associated risks would be very low. The storage potential is difficult to estimate at this early phase of development. It would be limited by the fraction of silicate reserves that can be technically exploited, by environmental issues such as the volume of product disposal, and by legal and societal constraints at the storage location.

The process of mineral carbonation occurs naturally, where it is known as 'weathering'. In nature, the process occurs very slowly; it must therefore be accelerated considerably to be a viable storage method for CO$_2$ captured from anthropogenic sources. Research in the field of mineral carbonation therefore focuses on finding process routes that can achieve reaction rates viable for industrial purposes and make the reaction more energy-efficient. Mineral carbonation technology using natural silicates is in the research phase but some processes using industrial wastes are in the demonstration phase.

A commercial process would require mining, crushing and milling of the mineral-bearing ores and their transport to a processing plant receiving a concentrated CO$_2$ stream from a capture plant (see Figure TS.10). The carbonation process

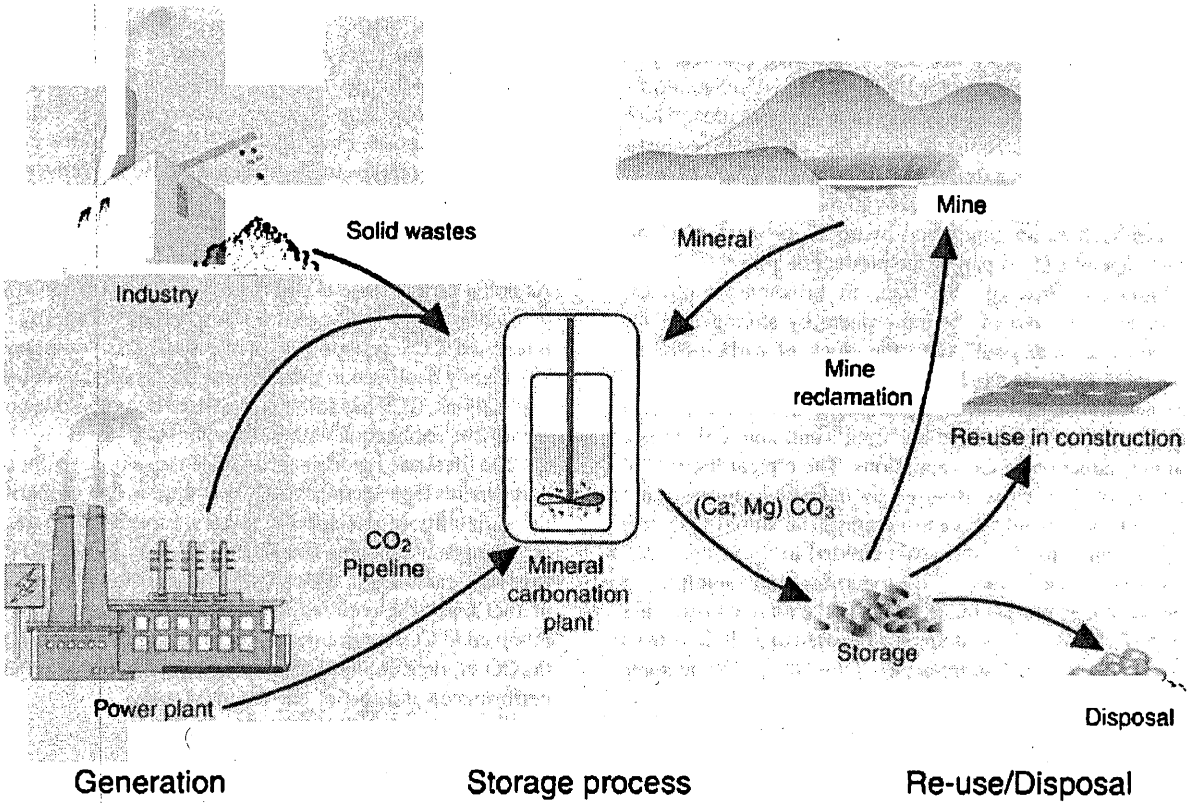

Figure TS.10. Material fluxes and process steps associated with the mineral carbonation of silicate rocks or industrial residues (Courtesy ECN).

energy required would be 30 to 50% of the capture plant output. Considering the additional energy requirements for the capture of CO_2, a CCS system with mineral carbonation would require 60 to 180% more energy input per kilowatt-hour than a reference electricity plant without capture or mineral carbonation. These energy requirements raise the cost per tonne of CO_2 avoided for the overall system significantly (see Section 8). The best case studied so far is the wet carbonation of natural silicate olivine. The estimated cost of this process is approximately 50–100 US$/t$CO_2$ net mineralized (in addition to CO_2 capture and transport costs, but taking into account the additional energy requirements). The mineral carbonation process would require 1.6 to 3.7 tonnes of silicates per tonne of CO_2 to be mined, and produce 2.6 to 4.7 tonnes of materials to be disposed per tonne of CO_2 stored as carbonates. This would therefore be a large operation, with an environmental impact similar to that of current large-scale surface mining operations. Serpentine also often contains chrysotile, a natural form of asbestos. Its presence therefore demands monitoring and mitigation measures of the kind available in the mining industry. On the other hand, the products of mineral carbonation are chrysotile-free, since this is the most reactive component of the rock and therefore the first substance converted to carbonates.

A number of issues still need to be clarified before any estimates of the storage potential of mineral carbonation can be given. The issues include assessments of the technical feasibility and corresponding energy requirements at large scales, but also the fraction of silicate reserves that can be technically and economically exploited for CO_2 storage. The environmental impact of mining, waste disposal and product storage could also limit potential. The extent to which mineral carbonation may be used cannot be determined at this time, since it depends on the unknown amount of silicate reserves that can be technically exploited, and environmental issuessuch as those noted above.

Industrial uses

Industrial uses of CO_2 include chemical and biological processes where CO_2 is a reactant, such as those used in urea and methanol production, as well as various technological applications that use CO_2 directly, for example in the horticulture industry, refrigeration, food packaging, welding, beverages and fire extinguishers. Currently, CO_2 is used at a rate of approximately 120 $MtCO_2$ per year (30 MtC yr^{-1}) worldwide, excluding use for EOR (discussed in Section 5). Most (two thirds of the total) is used to produce urea, which is used in the manufacture of fertilizers and other products. Some of the CO_2 is extracted from natural wells, and some originates from industrial sources – mainly high-concentration sources such as ammonia and hydrogen production plants – that capture CO_2 as part of the production process.

Industrial uses of CO_2 can, in principle, contribute to keeping CO_2 out of the atmosphere by storing it in the "carbon chemical pool" (i.e., the stock of carbon-bearing manufactured products). However, as a measure for mitigating climate change, this option is meaningful only if the quantity and duration of CO_2 stored are significant, and if there is a real net reduction of CO_2 emissions. The typical lifetime of most of the CO_2 currently used by industrial processes has storage times of only days to months. The stored carbon is then degraded to CO_2 and again emitted to the atmosphere. Such short time scales do not contribute meaningfully to climate change mitigation. In addition, the total industrial use figure of 120 $MtCO_2$ yr^{-1} is small compared to emissions from major anthropogenic sources (see Table TS.2). While some industrial processes store a small proportion of CO_2 (totalling roughly 20 $MtCO_2$ yr^{-1}) for up to several decades, the total amount of long-term (century-scale) storage is presently in the order of 1 $MtCO_2$ yr^{-1} or less, with no prospects for major increases.

Another important question is whether industrial uses of CO_2 can result in an overall net reduction of CO_2 emissions by substitution for other industrial processes or products. This can be evaluated correctly only by considering proper system boundaries for the energy and material balances of the CO_2 utilization processes, and by carrying out a detailed life-cycle analysis of the proposed use of CO_2. The literature in this area is limited but it shows that precise figures are difficult to estimate and that in many cases industrial uses could lead to an increase in overall emissions rather than a net reduction. In view of the low fraction of CO_2 retained, the small volumes used and the possibility that substitution may lead to increases in CO_2 emissions, it can be concluded that the contribution of industrial uses of captured CO_2 to climate change mitigation is expected to be small.

8. Costs and economic potential

The stringency of future requirements for the control of greenhouse gas emissions and the expected costs of CCS systems will determine, to a large extent, the future deployment of CCS technologies relative to other greenhouse gas mitigation options. This section first summarizes the overall cost of CCS for the main options and process applications considered in previous sections. As used in this summary and the report, "costs" refer only to market prices but do not include external costs such as environmental damages and broader societal costs that may be associated with the use of CCS. To date, little has been done to assess and quantify such external costs. Finally CCS is examined in the context of alternative options for global greenhouse gas reductions.

Cost of CCS systems

As noted earlier, there is still relatively little experience with the combination of CO_2 capture, transport and storage in a fully integrated CCS system. And while some CCS components are already deployed in mature markets for certain industrial applications, CCS has still not been used in large-scale power plants (the application with most potential).

The literature reports a fairly wide range of costs for CCS components (see Sections 3–7). The range is due primarily to the variability of site-specific factors, especially the design, operating and financing characteristics of the power plants or industrial facilities in which CCS is used; the type and costs of fuel used; the required distances, terrains and quantities involved in CO_2 transport; and the type and characteristics of the CO_2 storage. In addition, uncertainty still remains about the performance and cost of current and future CCS technology components and integrated systems. The literature reflects a widely-held belief, however, that the cost of building and operating CO_2 capture systems will decline over time as a result of learning-by-doing (from technology deployment) and sustained R&D. Historical evidence also suggests that costs for first-of-a-kind capture plants could exceed current estimates before costs subsequently decline. In most CCS systems, the cost of capture (including compression) is the largest cost component. Costs of electricity and fuel vary considerably from country to country, and these factors also influence the economic viability of CCS options.

Table TS.9 summarizes the costs of CO_2 capture, transport and storage reported in Sections 3 to 7. Monitoring costs are also reflected. In Table TS.10, the component costs are combined to show the total costs of CCS and electricity generation for three power systems with pipeline transport and two geological storage options.

For the plants with geological storage and no EOR credit, the cost of CCS ranges from 0.02–0.05 US$/kWh for PC plants and 0.01–0.03 US$/kWh for NGCC plants (both employing post-combustion capture). For IGCC plants (using pre-combustion capture), the CCS cost ranges from 0.01–0.03 US$/kWh relative to a similar plant without CCS. For all electricity systems, the cost of CCS can be reduced by about 0.01–0.02 US$/kWh when using EOR with CO_2 storage because the EOR revenues partly compensate for the CCS costs. The largest cost reductions are seen for coal-based plants, which capture the largest amounts of CO_2. In a few cases, the low end of the CCS cost range can be negative,

Table TS.9. 2002 Cost ranges for the components of a CCS system as applied to a given type of power plant or industrial source. The costs of the separate components cannot simply be summed to calculate the costs of the whole CCS system in US\$/CO_2 avoided. All numbers are representative of the costs for large-scale, new installations, with natural gas prices assumed to be 2.8-4.4 US\$ GJ^{-1} and coal prices 1-1.5 US\$ GJ^{-1}.

CCS system components	Cost range	Remarks
Capture from a coal- or gas-fired power plant	15-75 US\$/tCO_2 net captured	Net costs of captured CO_2, compared to the same plant without capture.
Capture from hydrogen and ammonia production or gas processing	5-55 US\$/tCO_2 net captured	Applies to high-purity sources requiring simple drying and compression.
Capture from other industrial sources	25-115 US\$/tCO_2 net captured	Range reflects use of a number of different technologies and fuels.
Transportation	1-8 US\$/tCO_2 transported	Per 250 km pipeline or shipping for mass flow rates of 5 (high end) to 40 (low end) MtCO_2 yr^{-1}.
Geological storage[a]	0.5-8 US\$/tCO_2 net injected	Excluding potential revenues from EOR or ECBM.
Geological storage: monitoring and verification	0.1-0.3 US\$/tCO_2 injected	This covers pre-injection, injection, and post-injection monitoring, and depends on the regulatory requirements.
Ocean storage	5-30 US\$/tCO_2 net injected	Including offshore transportation of 100-500 km, excluding monitoring and verification.
Mineral carbonation	50-100 US\$/tCO_2 net mineralized	Range for the best case studied. Includes additional energy use for carbonation.

[a] Over the long term, there may be additional costs for remediation and liabilities.

indicating that the assumed credit for EOR over the life of the plant is greater than the lowest reported cost of CO_2 capture for that system. This might also apply in a few instances of low-cost capture from industrial processes.

In addition to fossil fuel-based energy conversion processes, CO_2 could also be captured in power plants fueled with biomass, or fossil-fuel plants with biomass co-firing. At present, biomass plants are small in scale (less than 100 MW_e). This means that the resulting costs of production with and without CCS are relatively high compared to fossil alternatives. Full CCS costs for biomass could amount to 110 US\$/tCO_2 avoided. Applying CCS to biomass-fuelled or co-fired conversion facilities would lead to lower or negative[13] CO_2 emissions, which could reduce the costs for this option, depending on the market value of CO_2 emission reductions. Similarly, CO_2 could be captured in biomass-fueled H_2 plants. The cost is reported to be 22–25 US\$/tCO_2 (80–92 US\$/tC) avoided in a plant producing 1 million Nm^3 day^{-1} of H_2, and corresponds to an increase in the H_2 product costs of about 2.7 US\$ GJ^{-1}. Significantly larger biomass plants could potentially benefit from economies of scale, bringing down costs of the CCS systems to levels broadly similar to coal plants. However, to date, there has been little experience with large-scale biomass plants, so their feasibility has not been proven yet, and costs and potential are difficult to estimate.

The cost of CCS has not been studied in the same depth for non-power applications. Because these sources are very diverse in terms of CO_2 concentration and gas stream pressure, the available cost studies show a very broad range. The lowest costs were found for processes that already separate CO_2 as part of the production process, such as hydrogen production (the cost of capture for hydrogen production was reported earlier in Table TS.4). The full CCS cost, including transport and storage, raises the cost of hydrogen production by 0.4 to 4.4 US\$ GJ^{-1} in the case of geological storage, and by -2.0 to 2.8 US\$ GJ^{-1} in the case of EOR, based on the same cost assumptions as for Table TS.10.

Cost of CO_2 avoided

Table TS.10 also shows the ranges of costs for 'CO_2 avoided'. CCS energy requirements push up the amount of fuel input (and therefore CO_2 emissions) per unit of net power output. As a result, the amount of CO_2 produced per unit of product (a kWh of electricity) is greater for the power plant with CCS than the reference plant, as shown in Figure TS.11. To determine the CO_2 reductions one can attribute to CCS, one needs to compare CO_2 emissions per kWh of the plant with capture to that of a reference plant without capture. The difference is referred to as the 'avoided emissions'.

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[13] If for example the biomass is harvested at an unsustainable rate (that is, faster than the annual re-growth), the net CO_2 emissions of the activity might not be negative.

Table TS.10. Range of total costs for CO_2 capture, transport and geological storage based on current technology for new power plants using bituminous coal or natural gas

Power plant performance and cost parameters[a]	Pulverized coal power plant	Natural gas combined cycle power plant	Integrated coal gasification combined cycle power plant
Reference plant without CCS			
Cost of electricity (US$/kWh)	0.043-0.052	0.031-0.050	0.041-0.061
Power plant with capture			
Increased fuel requirement (%)	24-40	11-22	14-25
CO_2 captured (kg/kWh)	0.82-0.97	0.36-0.41	0.67-0.94
CO_2 avoided (kg/kWh)	0.62-0.70	0.30-0.32	0.59-0.73
% CO_2 avoided	81-88	83-88	81-91
Power plant with capture and geological storage[b]			
Cost of electricity (US$/kWh)	0.063-0.099	0.043-0.077	0.055-0.091
Cost of CCS (US$/kWh)	0.019-0.047	0.012-0.029	0.010-0.032
% increase in cost of electricity	43-91	37-85	21-78
Mitigation cost (US$/t$CO_2$ avoided)	30-71	38-91	14-53
(US$/tC avoided)	110-260	140-330	51-200
Power plant with capture and enhanced oil recovery[c]			
Cost of electricity (US$/kWh)	0.049-0.081	0.037-0.070	0.040-0.075
Cost of CCS (US$/kWh)	0.005-0.029	0.006-0.022	(-0.005)-0.019
% increase in cost of electricity	12-57	19-63	(-10)-46
Mitigation cost (US$/t$CO_2$ avoided)	9-44	19-68	(-7)-31
(US$/tC avoided)	31-160	71-250	(-25)-120

[a] All changes are relative to a similar (reference) plant without CCS. See Table TS.3 for details of assumptions underlying reported cost ranges.

[b] Capture costs based on ranges from Table TS.3; transport costs range from 0-5 US$/t$CO_2$; geological storage cost ranges from 0.6-8.3 US$/t$CO_2$.

Same capture and transport costs as above; Net storage costs for EOR range from -10 to -16 US$/t$CO_2$ (based on pre-2003 oil prices of 15-20 US$ per barrel).

Introducing CCS to power plants may influence the decision about which type of plant to install and which fuel to use. In some situations therefore, it can be useful to calculate a cost per tonne of CO_2 avoided based on a reference plant different from the CCS plant. Table TS.10 displays the cost and emission factors for the three reference plants and the corresponding CCS plants for the case of geological storage. Table TS.11 summarizes the range of estimated costs for different combinations of CCS plants and the lowest-cost reference plants of potential interest. It shows, for instance, that where a PC plant is planned initially, using CCS in that plant may lead to a higher CO_2 avoidance cost than if an NGCC plant with CCS is selected, provided natural gas is available. Another option with lower avoidance cost could be to build an IGCC plant with capture instead of equipping a PC plant with capture.

Economic potential of CCS for climate change mitigation

Assessments of the economic potential of CCS are based on energy and economic models that study future CCS deployment and costs in the context of scenarios that achieve economically efficient, least-cost paths to the stabilization of atmospheric CO_2 concentrations.

While there are significant uncertainties in the quantitative results from these models (see discussion below), all models indicate that CCS systems are unlikely to be deployed on a large scale in the absence of an explicit policy that substantially limits greenhouse gas emissions to the atmosphere. With greenhouse gas emission limits imposed, many integrated assessments foresee the deployment of CCS systems on a large scale within a few decades from the start of any significant climate change mitigation regime. Energy and economic models indicate that CCS systems

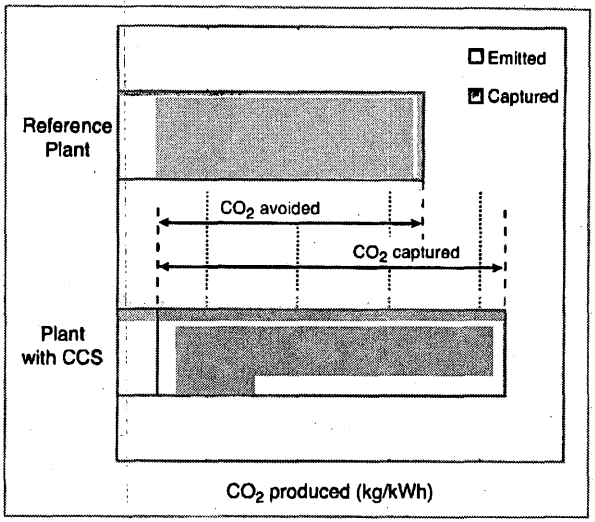

Figure TS.11. CO_2 capture and storage from power plants. The increased CO_2 production resulting from loss in overall efficiency of power plants due to the additional energy required for capture, transport and storage, and any leakage from transport result in a larger amount of "CO_2 produced per unit of product" (lower bar) relative to the reference plant (upper bar) without capture.

are unlikely to contribute significantly to the mitigation of climate change unless deployed in the power sector. For this to happen, the price of carbon dioxide reductions would have to exceed 25–30 US\$/tCO_2, or an equivalent limit on CO_2 emissions would have to be mandated. The literature and current industrial experience indicate that, in the absence of measures for limiting CO_2 emissions, there are only small, niche opportunities for CCS technologies to deploy. These early opportunities involve CO_2 captured from a high-purity, low-cost source, the transport of CO_2 over distances of less than 50 km, coupled with CO_2 storage in a value-added application such as EOR. The potential of such niche options is about 360 MtCO_2 per year (see Section 2).

Models also indicate that CCS systems will be competitive with other large-scale mitigation options such as nuclear power and renewable energy technologies. These studies show that including CCS in a mitigation portfolio could reduce the cost of stabilizing CO_2 concentrations by 30% or more. One aspect of the cost competitiveness of CCS technologies is that they are compatible with most current energy infrastructures.

In most scenarios, emissions abatement becomes progressively more constraining over time. Most analyses indicate that notwithstanding significant penetration of CCS systems by 2050, the majority of CCS deployment will occur in the second half of this century. The earliest CCS deployments are typically foreseen in the industrialized nations, with deployment eventually spreading worldwide. While results for different scenarios and models differ (often

Table TS.11. Mitigation cost ranges for different combinations of reference and CCS plants based on current technology for new power plants. Currently, in many regions, common practice would be either a PC plant or an NGCC plant[14]. EOR benefits are based on oil prices of 15 - 20 US\$ per barrel. Gas prices are assumed to be 2.8 -4.4 US\$/GJ^{-1}, coal prices 1-1.5 US\$/GJ^{-1} (based on Table 8.3a).

CCS plant type	NGCC reference plant US\$/tCO_2 avoided (US\$/tC avoided)	PC reference plant US\$/tCO_2 avoided (US\$/tC avoided)
Power plant with capture and geological storage		
NGCC	40 - 90 (140 - 330)	20 - 60 (80 - 220)
PC	70 - 270 (260 - 980)	30 - 70 (110 - 260)
IGCC	40 - 220 (150 - 790)	20 - 70 (80 - 260)
Power plant with capture and EOR		
NGCC	20 - 70 (70 - 250)	0 - 30 (0 - 120)
PC	50 - 240 (180 - 890)	10 - 40 (30 - 160)
IGCC	20 - 190 (80 - 710)	0 - 40 (0 - 160)

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[14] IGCC is not included as a reference power plant that would be built today since this technology is not yet widely deployed in the electricity sector and is usually slightly more costly than a PC plant.

significantly) in the specific mix and quantities of different measures needed to achieve a particular emissions constraint (see Figure TS.12), the consensus of the literature shows that CCS could be an important component of the broad portfolio of energy technologies and emission reduction approaches.

The actual use of CCS is likely to be lower than the estimates of economic potential indicated by these energy and economic models. As noted earlier, the results are typically based on an optimized least-cost analysis that does not adequately account for real-world barriers to technology development and deployment, such as environmental impact, lack of a clear legal or regulatory framework, the perceived investment risks of different technologies, and uncertainty as to how quickly the cost of CCS will be reduced through R&D and learning-by-doing. Models typically employ simplified assumptions regarding the costs of CCS for different applications and the rates at which future costs will be reduced.

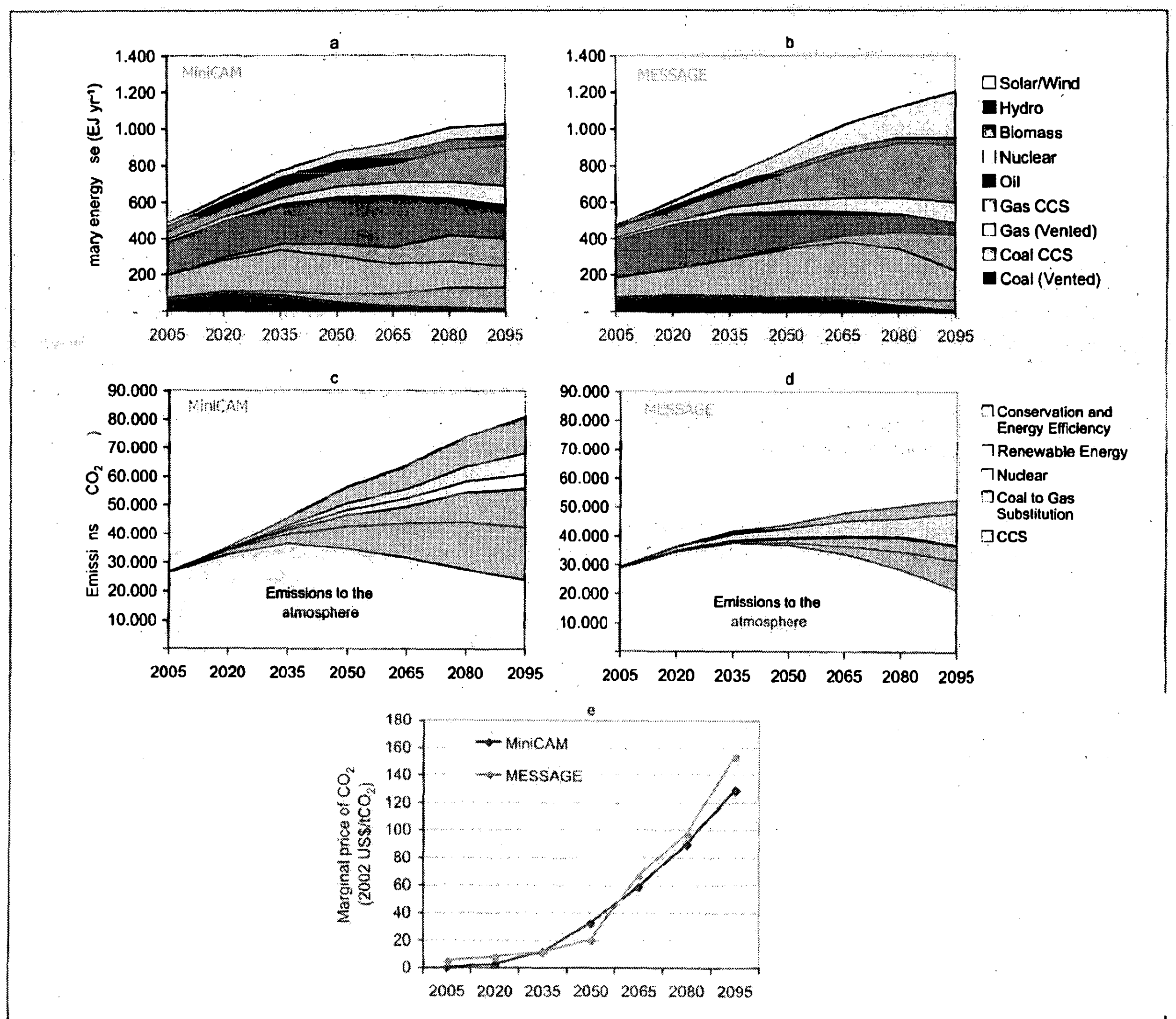

Figure TS.12. These figures are an illustrative example of the global potential contribution of CCS as part of a mitigation portfolio. They are based on two alternative integrated assessment models (MESSAGE and MiniCAM) adopting the same assumptions for the main emissions drivers. The results would vary considerably on regional scales. This example is based on a single scenario and therefore does not convey the full range of uncertainties. Panels a) and b) show global primary energy use, including the deployment of CCS. Panels c) and d) show the global CO_2 emissions in grey and corresponding contributions of main emissions reduction measures in colour. Panel e) shows the calculated marginal price of CO_2 reductions.

For CO_2 stabilization scenarios between 450 and 750 ppmv, published estimates of the cumulative amount of CO_2 potentially stored globally over the course of this century (in geological formations and/or the oceans) span a wide range, from very small contributions to thousands of gigatonnes of CO_2. To a large extent, this wide range is due to the uncertainty of long-term socio-economic, demographic and, in particular, technological changes, which are the main drivers of future CO_2 emissions. However, it is important to note that the majority of results for stabilization scenarios of 450–750 ppmv CO_2 tend to cluster in a range of 220–2,200 $GtCO_2$ (60–600 GtC) for the cumulative deployment of CCS. For CCS to achieve this economic potential, several hundreds or thousands of CCS systems would be required worldwide over the next century, each capturing some 1–5 $MtCO_2$ per year. As indicated in Section 5, it is likely that the technical potential for geological storage alone is sufficient to cover the high end of the economic potential range for CCS.

Perspectives on CO_2 leakage from storage

The policy implications of slow leakage from storage depend on assumptions in the analysis. Studies conducted to address the question of how to deal with impermanent storage are based on different approaches: the value of delaying emissions, cost minimization of a specified mitigation scenario, or allowable future emissions in the context of an assumed stabilization of atmospheric greenhouse gas concentrations. Some of these studies allow future releases to be compensated by additional reductions in emissions; the results depend on assumptions regarding the future cost of reductions, discount rates, the amount of CO_2 stored, and the assumed level of stabilization for atmospheric concentrations. In other studies, compensation is not seen as an option because of political and institutional uncertainties and the analysis focuses on limitations set by the assumed stabilization level and the amount stored.

While specific results of the range of studies vary with the methods and assumptions made, the outcomes suggest that a fraction retained on the order of 90–99% for 100 years or 60–95% for 500 years could still make such impermanent storage valuable for the mitigation of climate change. All studies imply that, if CCS is to be acceptable as a mitigation measure, there must be an upper limit to the amount of leakage that can take place.

9. Emission inventories and accounting

An important aspect of CO_2 capture and storage is the development and application of methods to estimate and report the quantities in which emissions of CO_2 (and associated emissions of methane or nitrous oxides) are reduced, avoided, or removed from the atmosphere. The two elements involved here are (1) the actual estimation and reporting of emissions for national greenhouse gas inventories, and (2) accounting for CCS under international agreements to limit net emissions.[15]

Current framework

Under the UNFCCC, national greenhouse gas emission inventories have traditionally reported emissions for a specific year, and have been prepared on an annual basis or another periodic basis. The IPCC Guidelines (IPCC 1996) and Good Practice Guidance Reports (IPCC 2000; 2003) describe detailed approaches for preparing national inventories that are complete, transparent, documented, assessed for uncertainties, consistent over time, and comparable across countries. The IPCC documents now in use do not specifically include CO_2 capture and storage options. However, the IPCC Guidelines are currently undergoing revisions that should provide some guidance when the revisions are published in 2006. The framework that already has been accepted could be applied to CCS systems, although some issues might need revision or expansion.

Issues relevant to accounting and reporting

In the absence of prevailing international agreements, it is not clear whether the various forms of CO_2 capture and storage will be treated as reductions in emissions or as removals from the atmosphere. In either case, CCS results in new pools of CO_2 that may be subject to physical leakage at some time in the future. Currently, there are no methods available within the UNFCCC framework for monitoring, measuring or accounting for physical leakage from storage sites. However, leakage from well-managed geological storage sites is likely to be small in magnitude and distant in time.

Consideration may be given to the creation of a specific category for CCS in the emissions reporting framework but this is not strictly necessary since the quantities of CO_2 captured and stored could be reflected in the sector in which the CO_2 was produced. CO_2 storage in a given location could include CO_2 from many different source categories, and even from sources in many different countries. Fugitive

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[15] In this context, "estimation" is the process of calculating greenhouse gas emissions and "reporting" is the process of providing the estimates to the UNFCCC. "Accounting" refers to the rules for comparing emissions and removals as reported with commitments (IPCC 2003).

emissions from the capture, transport and injection of CO_2 to storage can largely be estimated within the existing reporting methods, and emissions associated with the added energy required to operate the CCS systems can be measured and reported within the existing inventory frameworks. Specific consideration may also be required for CCS applied to biomass systems as that application would result in reporting negative emissions, for which there is currently no provision in the reporting framework.

Issues relevant to international agreements

Quantified commitments to limit greenhouse gas emissions and the use of emissions trading, Joint Implementation (JI) or the Clean Development Mechanism (CDM) require clear rules and methods to account for emissions and removals. Because CCS has the potential to move CO_2 across traditional accounting boundaries (e.g. CO_2 might be captured in one country and stored in another, or captured in one year and partly released from storage in a later year), the rules and methods for accounting may be different than those used in traditional emissions inventories.

To date, most of the scientific, technical and political discussions on accounting for stored CO_2 have focused on sequestration in the terrestrial biosphere. The history of these negotiations may provide some guidance for the development of accounting methods for CCS. Recognizing the potential impermanence of CO_2 stored in the terrestrial biosphere, the UNFCCC accepted the idea that net emissions can be reduced through biological sinks, but has imposed complex rules for such accounting. CCS is markedly different in many ways from CO_2 sequestration in the terrestrial biosphere (see Table TS.12), and the different forms of CCS are markedly different from one another. However, the main goal of accounting is to ensure that CCS activities produce real and quantifiable reductions in net emissions. One tonne of CO_2 permanently stored has the same benefit in terms of atmospheric CO_2 concentrations as one tonne of CO_2 not emitted, but one tonne of CO_2 temporarily stored has less benefit. It is generally accepted that this difference should be reflected in any system of accounting for reductions in net greenhouse gas emissions.

The IPCC Guidelines (IPCC 1996) and Good Practice Guidance Reports (IPCC 2000; 2003) also contain guidelines for monitoring greenhouse gas emissions. It is not known whether the revised guidelines of the IPCC for CCS can be satisfied by using monitoring techniques, particularly for geological and ocean storage. Several techniques are available for the monitoring and verification of CO_2 emissions from geological storage, but they vary in applicability, detection limits and uncertainties. Currently, monitoring for geological storage can take place quantitatively at injection and qualitatively in the reservoir and by measuring surface fluxes of CO_2. Ocean storage monitoring can take place by

Table TS.12. Differences in the forms of CCS and biological sinks that might influence the way accounting is conducted.

Property	Terrestrial biosphere	Deep ocean	Geological reservoirs
CO_2 sequestered or stored	Stock changes can be monitored over time.	Injected carbon can be measured.	Injected carbon can be measured.
Ownership	Stocks will have a discrete location and can be associated with an identifiable owner.	Stocks will be mobile and may reside in international waters.	Stocks may reside in reservoirs that cross national or property boundaries and differ from surface boundaries.
Management decisions	Storage will be subject to continuing decisions about land-use priorities.	Once injected there are no further human decisions about maintenance once injection has taken place.	Once injection has taken place, human decisions about continued storage involve minimal maintenance, unless storage interferes with resource recovery.
Monitoring	Changes in stocks can be monitored.	Changes in stocks will be modelled.	Release of CO_2 can be detected by physical monitoring.
Expected retention time	Decades, depending on management decisions.	Centuries, depending on depth and location of injection.	Essentially permanent, barring physical disruption of the reservoir.
Physical leakage	Losses might occur due to disturbance, climate change, or land-use decisions.	Losses will assuredly occur as an eventual consequence of marine circulation and equilibration with the atmosphere.	Losses are unlikely except in the case of disruption of the reservoir or the existence of initially undetected leakage pathways.
Liability	A discrete land-owner can be identified with the stock of sequestered carbon.	Multiple parties may contribute to the same stock of stored CO_2 and the CO_2 may reside in international waters.	Multiple parties may contribute to the same stock of stored CO_2 that may lie under multiple countries.

detecting the CO_2 plume, but not by measuring ocean surface release to the atmosphere. Experiences from monitoring existing CCS projects are still too limited to serve as a basis for conclusions about the physical leakage rates and associated uncertainties.

The Kyoto Protocol creates different units of accounting for greenhouse gas emissions, emissions reductions, and emissions sequestered under different compliance mechanisms. 'Assigned amount units' (AAUs) describe emissions commitments and apply to emissions trading, 'certified emission reductions' (CERs) are used under the CDM, and 'emission reduction units' (ERUs) are employed under JI. To date, international negotiations have provided little guidance about methods for calculating and accounting for project-related CO_2 reductions from CCS systems (only CERs or ERUs), and it is therefore uncertain how such reductions will be accommodated under the Kyoto Protocol. Some guidance may be given by the methodologies for biological-sink rules. Moreover, current agreements do not deal with cross-border CCS projects. This is particularly important when dealing with cross-border projects involving CO_2 capture in an 'Annex B' country that is party to the Kyoto Protocol but stored in a country that is not in Annex B or is not bound by the Protocol.

Although methods currently available for national emissions inventories can either accommodate CCS systems or be revised to do so, accounting for stored CO_2 raises questions about the acceptance and transfer of responsibility for stored emissions. Such issues may be addressed through national and international political processes.

10. Gaps in knowledge

This summary of the gaps in knowledge covers aspects of CCS where increasing knowledge, experience and reducing uncertainty would be important to facilitate decision-making about the large-scale deployment of CCS.

Technologies for capture and storage

Technologies for the capture of CO_2 are relatively well understood today based on industrial experience in a variety of applications. Similarly, there are no major technical or knowledge barriers to the adoption of pipeline transport, or to the adoption of geological storage of captured CO_2. However, the integration of capture, transport and storage in full-scale projects is needed to gain the knowledge and experience required for a more widespread deployment of CCS technologies. R&D is also needed to improve knowledge of emerging concepts and enabling technologies for CO_2 capture that have the potential to significantly reduce the costs of capture for new and existing facilities. More specifically, there are knowledge gaps relating to large coal-based and natural gas-based power plants with CO_2 capture on the order of several hundred megawatts (or several $MtCO_2$). Demonstration of CO_2 capture on this scale is needed to establish the reliability and environmental performance of different types of power systems with capture, to reduce the costs of CCS, and to improve confidence in the cost estimates. In addition, large-scale implementation is needed to obtain better estimates of the costs and performance of CCS in industrial processes, such as the cement and steel industries, that are significant sources of CO_2 but have little or no experience with CO_2 capture.

With regard to mineral carbonation technology, a major question is how to exploit the reaction heat in practical designs that can reduce costs and net energy requirements. Experimental facilities at pilot scales are needed to address these gaps.

With regard to industrial uses of captured CO_2, further study of the net energy and CO_2 balance of industrial processes that use the captured CO_2 could help to establish a more complete picture of the potential of this option.

Geographical relationship between the sources and storage opportunities of CO_2

An improved picture of the proximity of major CO_2 sources to suitable storage sites (of all types), and the establishment of cost curves for the capture, transport and storage of CO_2, would facilitate decision-making about large-scale deployment of CCS. In this context, detailed regional assessments are required to evaluate how well large CO_2 emission sources (both current and future) match suitable storage options that can store the volumes required.

Geological storage capacity and effectiveness

There is a need for improved storage capacity estimates at the global, regional and local levels, and for a better understanding of long-term storage, migration and leakage processes. Addressing the latter issue will require an enhanced ability to monitor and verify the behaviour of geologically stored CO_2. The implementation of more pilot and demonstration storage projects in a range of geological, geographical and economic settings would be important to improve our understanding of these issues.

Impacts of ocean storage

Major knowledge gaps that should be filled before the risks and potential for ocean storage can be assessed concern the ecological impact of CO_2 in the deep ocean. Studies are needed of the response of biological systems in the deep sea to added CO_2, including studies that are longer in duration and larger in scale than those that have been performed until now. Coupled with this is a need to develop techniques and sensors to detect and monitor CO_2 plumes and their biological and geochemical consequences.

Legal and regulatory issues

Current knowledge about the legal and regulatory requirements for implementing CCS on a larger scale is still inadequate. There is no appropriate framework to facilitate the implementation of geological storage and take into account the associated long-term liabilities. Clarification is needed regarding potential legal constraints on storage in the marine environment (ocean or sub-seabed geological storage). Other key knowledge gaps are related to the methodologies for emissions inventories and accounting.

Global contribution of CCS to mitigating climate change

There are several other issues that would help future decision-making about CCS by further improving our understanding of the potential contribution of CCS to the long-term global mitigation and stabilization of greenhouse gas concentrations. These include the potential for transfer and diffusion of CCS technologies, including opportunities for developing countries to exploit CCS, its application to biomass sources of CO_2, and the potential interaction between investment in CCS and other mitigation options. Further investigation is warranted into the question of how long CO_2 would need to be stored. This issue is related to stabilization pathways and intergenerational aspects.

3

Capture of CO_2

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Contents

EXECUTIVE SUMMARY

The purpose of CO_2 capture is to produce a concentrated stream that can be readily transported to a CO_2 storage site. CO_2 capture and storage is most applicable to large, centralized sources like power plants and large industries. Capture technologies also open the way for large-scale production of low-carbon or carbon-free electricity and fuels for transportation, as well as for small-scale or distributed applications. The energy required to operate CO_2 capture systems reduces the overall efficiency of power generation or other processes, leading to increased fuel requirements, solid wastes and environmental impacts relative to the same type of base plant without capture. However, as more efficient plants with capture become available and replace many of the older less efficient plants now in service, the net impacts will be compatible with clean air emission goals for fossil fuel use. Minimization of energy requirements for capture, together with improvements in the efficiency of energy conversion processes will continue to be high priorities for future technology development in order to minimize overall environmental impacts and cost.

At present, CO_2 is routinely separated at some large industrial plants such as natural gas processing and ammonia production facilities, although these plants remove CO_2 to meet process demands and not for storage. CO_2 capture also has been applied to several small power plants. However, there have been no applications at large-scale power plants of several hundred megawatts, the major source of current and projected CO_2 emissions. There are three main approaches to CO_2 capture, for industrial and power plant applications. *Post-combustion* systems separate CO_2 from the flue gases produced by combustion of a primary fuel (coal, natural gas, oil or biomass) in air. *Oxy-fuel combustion* uses oxygen instead of air for combustion, producing a flue gas that is mainly H_2O and CO_2 and which is readily captured. This is an option still under development. *Pre-combustion* systems process the primary fuel in a reactor to produce separate streams of CO_2 for storage and H_2 which is used as a fuel. Other industrial processes, including processes for the production of low-carbon or carbon-free fuels, employ one or more of these same basic capture methods. The monitoring, risk and legal aspects associated with CO_2 capture systems appear to present no new challenges, as they are all elements of long-standing health, safety and environmental control practice in industry.

For all of the aforementioned applications, we reviewed recent studies of the performance and cost of commercial or near-commercial technologies, as well as that of newer CO_2 capture concepts that are the subject of intense R&D efforts worldwide. For power plants, current commercial CO_2 capture systems can reduce CO_2 emissions by 80-90% kWh^{-1} (85-95% capture efficiency). Across all plant types the cost of electricity production (COE) increases by 12-36 US\$ MWh^{-1} (US\$ 0.012-0.036 kWh^{-1}) over a similar type of plant without capture, corresponding to a 40-85% increase for a supercritical pulverized coal (PC) plant, 35-70% for a natural gas combined cycle (NGCC) plant and 20-55% for an integrated gasification combined cycle (IGCC) plant using bituminous coal. Overall the COE for fossil fuel plants with capture, ranges from 43-86 US\$ MWh^{-1}, with the cost per tonne of CO_2 ranging from 11-57 US\$/tCO_2 captured or 13-74 US\$/tCO_2 avoided (depending on plant type, size, fuel type and a host of other factors). These costs include CO_2 compression but not additional transport and storage costs. NGCC systems typically have a lower COE than new PC and IGCC plants (with or without capture) for gas prices below about 4 US\$ GJ^{-1}. Most studies indicate that IGCC plants are slightly more costly without capture and slightly less costly with capture than similarly sized PC plants, but the differences in cost for plants with CO_2 capture can vary with coal type and other local factors. The lowest CO_2 capture costs (averaging about 12 US\$/tCO_2 captured or 15 US\$/tCO_2 avoided) were found for industrial processes such as hydrogen production plants that produce concentrated CO_2 streams as part of the current production process; such industrial processes may represent some of the earliest opportunities for CO_2 Capture and Storage (CCS). In all cases, CO_2 capture costs are highly dependent upon technical, economic and financial factors related to the design and operation of the production process or power system of interest, as well as the design and operation of the CO_2 capture technology employed. Thus, comparisons of alternative technologies, or the use of CCS cost estimates, require a specific context to be meaningful.

New or improved methods of CO_2 capture, combined with advanced power systems and industrial process designs, can significantly reduce CO_2 capture costs and associated energy requirements. While there is considerable uncertainty about the magnitude and timing of future cost reductions, this assessment suggests that improvements to commercial technologies can reduce CO_2 capture costs by at least 20-30% over approximately the next decade, while new technologies under development promise more substantial cost reductions. Realization of future cost reductions, however, will require deployment and adoption of commercial technologies in the marketplace as well as sustained R&D.

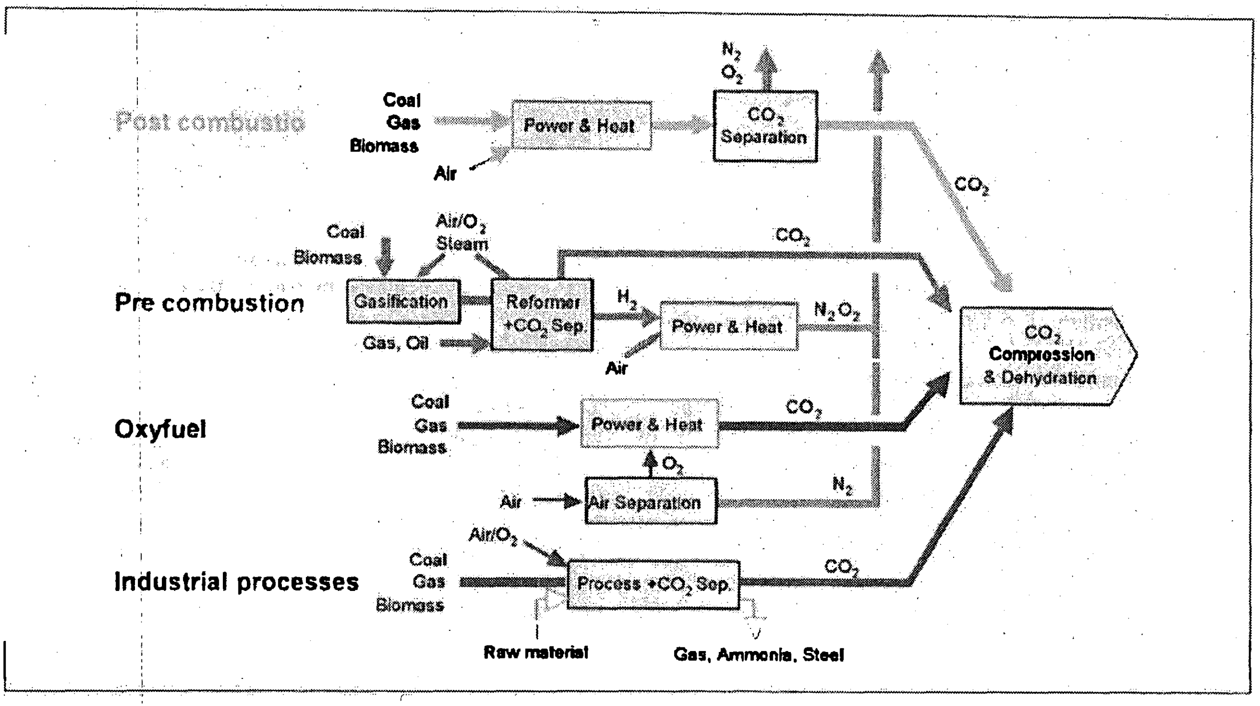


Figure 3.1 CO_2 capture systems (adapted from BP).

3.1 Introduction

3.1.1 The basis for CO_2 capture

The main application of CO_2 capture is likely to be at large point sources: fossil fuel power plants, fuel processing plants and other industrial plants, particularly for the manufacture of iron, steel, cement and bulk chemicals, as discussed in Chapter 2.

Capturing CO_2 directly from small and mobile sources in the transportation and residential & commercial building sectors is expected to be more difficult and expensive than from large point sources. Small-scale capture is therefore not further discussed in this chapter. An alternative way of avoiding emissions of CO_2 from these sources would be by use of energy carriers such as hydrogen or electricity produced in large fossil fuel-based plants with CO_2 capture or by using renewable energy sources. Production of hydrogen with CO_2 capture is included in this chapter.

The possibility of CO_2 capture from ambient air (Lackner, 2003) is not discussed in this chapter because the CO_2 concentration in ambient air is around 380 ppm, a factor of 100 or more lower than in flue gas. Capturing CO_2 from air by the growth of biomass and its use in industrial plants with CO_2 capture is more cost-effective based on foreseeable technologies, and is included in this chapter.

In an analysis of possible future scenarios for anthropogenic greenhouse-gas emissions it is implicit that technological innovations will be one of the key factors which determines our future path (Section 2.5.3). Therefore this chapter deals not only with application of existing technology for CO_2 capture, but describes many new processes under development which may result in lower CO_2 capture costs in future.

3.1.2 CO_2 capture systems

There are four basic systems for capturing CO_2 from use of fossil fuels and/or biomass:

- Capture from industrial process streams (described in Section 3.2);
- Post-combustion capture (described in Section 3.3);
- Oxy-fuel combustion capture (described in Section 3.4);
- Pre-combustion capture (described in Section 3.5).

These systems are shown in simplified form in Figure 3.1

3.1.2.1 Capture from industrial process streams

CO_2 has been captured from industrial process streams for 80 years (Kohl and Nielsen, 1997), although most of the CO_2 that is captured is vented to the atmosphere because there is no incentive or requirement to store it. Current examples of CO_2 capture from process streams are purification of natural gas and production of hydrogen-containing synthesis gas for the manufacture of ammonia, alcohols and synthetic liquid fuels. Most of the techniques employed for CO_2 capture in the examples mentioned are also similar to those used in pre-combustion capture. Other industrial process streams which are a source of CO_2 that is not captured include cement and steel production, and fermentation processes for food and drink production. CO_2 could be captured from these streams using techniques that are common to post-combustion capture, oxy-fuel combustion capture and pre-combustion capture (see below and Section 3.2).

3.1.2.2 Post-combustion capture

Capture of CO_2 from flue gases produced by combustion of fossil fuels and biomass in air is referred to as post-combustion capture. Instead of being discharged directly to the atmosphere, flue gas is passed through equipment which separates most of the CO_2. The CO_2 is fed to a storage reservoir and the remaining flue gas is discharged to the atmosphere. A chemical sorbent process as described in Section 3.1.3.1 would normally be used for CO_2 separation. Other techniques are also being considered but these are not at such an advanced stage of development.

Besides industrial applications, the main systems of reference for post-combustion capture are the current installed capacity of 2261 GW_e of oil, coal and natural gas power plants (IEA WEO, 2004) and in particular, 155 GW_e of supercritical pulverized coal fired plants (IEA CCC, 2005) and 339 GW_e of natural gas combined cycle (NGCC) plants, both representing the types of high efficiency power plant technology where CO_2 capture can be best applied (see Sections 3.3 and 3.7).

3.1.2.3 Oxy-fuel combustion capture

In oxy-fuel combustion, nearly pure oxygen is used for combustion instead of air, resulting in a flue gas that is mainly CO_2 and H_2O. If fuel is burnt in pure oxygen, the flame temperature is excessively high, but CO_2 and/or H_2O-rich flue gas can be recycled to the combustor to moderate this. Oxygen is usually produced by low temperature (cryogenic) air separation and novel techniques to supply oxygen to the fuel, such as membranes and chemical looping cycles are being developed. The power plant systems of reference for oxy-fuel combustion capture systems are the same as those noted above for post-combustion capture systems.

3.1.2.4 Pre-combustion capture

Pre-combustion capture involves reacting a fuel with oxygen or air and/or steam to give mainly a 'synthesis gas (syngas)' or 'fuel gas' composed of carbon monoxide and hydrogen. The carbon monoxide is reacted with steam in a catalytic reactor, called a shift converter, to give CO_2 and more hydrogen. CO_2 is then separated, usually by a physical or chemical absorption process, resulting in a hydrogen-rich fuel which can be used in many applications, such as boilers, furnaces, gas turbines, engines and fuel cells. These systems are considered to be strategically important (see Section 3.5) but the power plant systems of reference today are 4 GW_e of both oil and coal-based, integrated gasification combined cycles (IGCC) which are around 0.1% of total installed capacity worldwide (3719 GW_e; IEA WEO, 2004). Other reference systems for the application of pre-combustion capture include substantially more capacity than that identified above for IGCC in existing natural gas, oil and coal-based syngas/hydrogen production facilities and other types of industrial systems described in more detail in Sections 3.2 and 3.5.

3.1.3 Types of CO_2 capture technologies

CO_2 capture systems use many of the known technologies for gas separation which are integrated into the basic systems for CO_2 capture identified in the last section. A summary of these separation methods is given below while further details are available in standard textbooks.

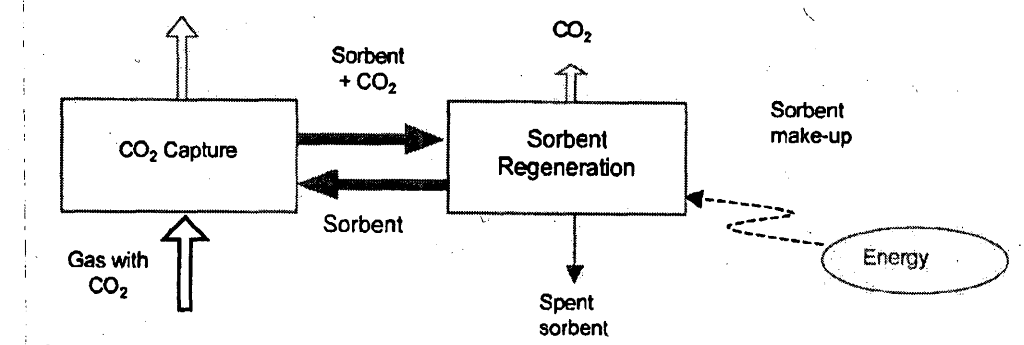
3.1.3.1 Separation with sorbents/solvents

The separation is achieved by passing the CO_2-containing gas in intimate contact with a liquid absorbent or solid sorbent that is capable of capturing the CO_2. In the general scheme of Figure 3.2a, the sorbent loaded with the captured CO_2 is transported to a different vessel, where it releases the CO_2 (regeneration) after being heated, after a pressure decrease or after any other change in the conditions around the sorbent. The sorbent resulting after the regeneration step is sent back to capture more CO_2 in a cyclic process. In some variants of this scheme the sorbent is a solid and does not circulate between vessels because the sorption and regeneration are achieved by cyclic changes (in pressure or temperature) in the vessel where the sorbent is contained. A make-up flow of fresh sorbent is always required to compensate for the natural decay of activity and/or sorbent losses. In some situations, the sorbent may be a solid oxide which reacts in a vessel with fossil fuel or biomass producing heat and mainly CO_2 (see Section 3.4.6). The spent sorbent is then circulated to a second vessel where it is re-oxidized in air for reuse with some loss and make up of fresh sorbent.

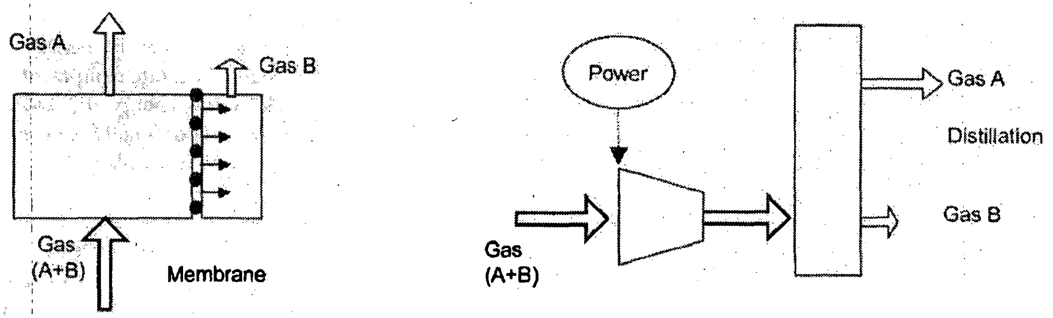
The general scheme of Figure 3.2 governs many important CO_2 capture systems, including leading commercial options like chemical absorption and physical absorption and adsorption. Other emerging processes based on new liquid sorbents, or new solid regenerable sorbents are being developed with the aim of overcoming the limitations of the existing systems. One common problem of these CO_2 capture systems is that the flow of sorbent between the vessels of Figure 3.2a is large because it has to match the huge flow of CO_2 being processed in the power plant. Therefore, equipment sizes and the energy required for sorbent regeneration are large and tend to translate into an important efficiency penalty and added cost. Also, in systems using expensive sorbent materials there is always a danger of escalating cost related to the purchase of the sorbent and the disposal of sorbent residues. Good sorbent performance under high CO_2 loading in many repetitive cycles is obviously a necessary condition in these CO_2 capture systems.

3.1.3.2 Separation with membranes

Membranes (Figure 3.2b) are specially manufactured materials that allow the selective permeation of a gas through them. The selectivity of the membrane to different gases is intimately related to the nature of the material, but the flow of gas through the membrane is usually driven by the pressure difference across the membrane. Therefore, high-pressure streams are usually preferred for membrane separation. There are many different types of membrane materials (polymeric, metallic, ceramic) that may find application in CO_2 capture systems to



a) Separation with sorbents/solvents



b) Separation with a membrane *c) Separation by cryogenic distillation*

Figure 3.2 General schemes of the main separation processes relevant for CO_2 capture. The gas removed in the separation may be CO_2, H_2 or O_2. In Figures 3.2b and 3.2c one of the separated gas streams (A and B) is a concentrated stream of CO_2, H_2 or O_2 and the other is a gas stream with all the remaining gases in the original gas (A+B).

preferentially separate H_2 from a fuel gas stream, CO_2 from a range of process streams or O_2 from air with the separated O_2 subsequently aiding the production of a highly concentrated CO_2 stream. Although membrane separation finds many current commercial applications in industry (some of a large scale, like CO_2 separation from natural gas) they have not yet been applied for the large scale and demanding conditions in terms of reliability and low-cost required for CO_2 capture systems. A large worldwide R&D effort is in progress aimed at the manufacture of more suitable membrane materials for CO_2 capture in large-scale applications.

3.1.3.3 Distillation of a liquefied gas stream and refrigerated separation

A gas can be made liquid by a series of compression, cooling and expansion steps. Once in liquid form, the components of the gas can be separated in a distillation column. In the case of air, this operation is currently carried out commercially on a large scale. Oxygen can be separated from air following the scheme of Figure 3.2c and be used in a range of CO_2 capture systems (oxy-fuel combustion and pre-combustion capture). As in the previous paragraphs, the key issue for these systems is the large flow of oxygen required. Refrigerated separation can also be used to separate CO_2 from other gases. It can be used to separate impurities from relatively high purity CO_2 streams, for example, from oxy-fuel combustion and for CO_2 removal from natural gas or synthesis gas that has undergone a shift conversion of CO to CO_2.

3.1.4 Application of CO_2 capture

The CO_2 capture systems shown in Figure 3.1 can be cross-referenced with the different separation technologies of Figure 3.2, resulting in a capture toolbox. Table 3.1 gives an overview of both current and emerging technologies in this toolbox. In the next sections of this chapter a more detailed description of all these technological options will be given, with more emphasis on the most developed technologies for which the CO_2 capture cost can be estimated most reliably. These leading commercial options are shown in bold in Table 3.1. An overview of the diverse range of emerging options being investigated worldwide for CO_2 capture applications will also be provided. All of these options are aimed at more efficient and lower cost CO_2-capture systems (compared with the leading options). It is important

Table apture toolbox.

paration task	**Process st ams***		**Post-com stion capture**		**Oxy-fuel combustion capt re**		**Pre-combustion c pture**	
	CO_2/CH_4		**CO_2/N_2**		**O_2/N_2**		**CO_2/H_2**	
Capture Technologies	**Cur t**	**Emergin**	**Current**	**Emerging**	**Current**	**Emerging**	**Current**	**Emerging**
Solvents (Absorption)	**Physical sol ents** **Chemical solvents**	Improved solvents Novel contacting equipment Improved design of processes	**Chemical solvents**	Improved solvents Novel contacting equipment Improved design cf processes	a.	metic solven s, :moglobine-tives	**Physical solvent** **Chemical solvents**	Improved chemical solvents Novel contacting equipment Improved design of processes
M mbranes	**Polymeric**	Ceramic Facilitated transport Carbon Contactors	Polyme ic	Ceramic Facilitated transport Carbon Contactors	Polymeric	Ion transport membranes Facilitated transport	Polymeric	Ceramic Palladium Reactors Contactors
Solid s rbents	Zeolites Activated carbon		Zeolites Activated carbon	Carbonates Carbon based sorbents	Zeolites Activated carbon	Adsorbents for O_2/N_2 separation, Perovskites Oxygen chemical looping	Zeolites Activated carb n Alumina	Carbonates Hydrotalcites Silicates
C genic	Ryan-H l process		Liquefaction	brid processes	**illation**	Improved distillation	Liq faction	Hybrid se

Notes: Processes wn in bold are co ercial processes that are cu tly ferred in most circumstances. S process treams involve CO_2/H_2 or CO_2/N_2 sepa i t this is ered unde pre-combustion captu nd post-combustion capture. The key separation ces are outlined in Section 1.3 an scribed in Sections 3.2-3.5.

to understand that this wide variety of approaches for CO_2 capture will tend to settle with time as the expected benefits (and potential weaknesses) in the technological portfolio of Table 3.1 becomes obvious with new results from current and future research and demonstration projects. Only a few of these options will prove truly cost-effective in the medium to long term.

CO_2 capture may be installed in new energy utilization plants or it may be retrofitted to existing plants. In principle, if CO_2 capture is to be introduced rapidly, it may have to be retrofitted to some existing plants or these plants would have to be retired prematurely and replaced by new plants with capture. Disadvantages of retrofits are:

- There may be site constraints such as availability of land for the capture equipment;
- A long remaining plant life may be needed to justify the large expense of installing capture equipment;
- Old plants tend to have low energy efficiencies. Including CO_2 capture will have a proportionally greater impact on the net output than in high efficiency plants.

To minimize the site constraints, new energy utilization plants could be built 'capture-ready', that is with the process design initially factoring in the changes necessary to add capture and with sufficient space and facilities made available for simple installation of CO_2 capture at a later date. For some types of capture retrofit, for example pre-combustion capture and oxy-fuel combustion, much of the retrofit equipment could be built on a separate site if necessary.

The other barriers could be largely overcome by upgrading or substantially rebuilding the existing plant when capture is retrofitted. For example, old inefficient boilers and steam turbines could be replaced by modern, high-efficiency supercritical boilers and turbines or IGCC plants. As the efficiencies of power generation technologies are increasing, the efficiency of the retrofitted plant with CO_2 capture could be as high as that of the original plant without capture.

3.2 Industrial process capture systems

3.2.1 *Introduction*

There are several industrial applications involving process streams where the opportunity exists to capture CO_2 in large quantities and at costs lower than from the systems described in the rest of this chapter. Capture from these sources will not be the complete answer to the needs of climate change, since the volumes of combustion-generated CO_2 are much higher, but it may well be the place where the first capture and storage occurs.

3.2.2 *Natural gas sweetening*

Natural gas contains different concentration levels of CO_2, depending on its source, which must be removed. Often pipeline specifications require that the CO_2 concentration be lowered to around 2% by volume (although this amount varies in different places) to prevent pipeline corrosion, to avoid excess energy for transport and to increase the heating value of the gas. Whilst accurate figures are published for annual worldwide natural gas production (BP, 2004), none seem to be published on how much of that gas may contain CO_2. Nevertheless, a reasonable assumption is that about half of raw natural gas production contains CO_2 at concentrations averaging at least 4% by volume. These figures can be used to illustrate the scale of this CO_2 capture and storage opportunity. If half of the worldwide production of 2618.5 billion m^3 of natural gas in 2003 is reduced in CO_2 content from 4 to 2% mol, the resultant amount of CO_2 removed would be at least 50 Mt CO_2 yr^{-1}. It is interesting to note that there are two operating natural gas plants capturing and storing CO_2, BP's In Salah plant in Algeria and a Statoil plant at Sleipner in the North Sea. Both capture about 1 $MtCO_2$ yr^{-1} (see Chapter 5). About 6.5 million tCO_2 yr^{-1} from natural gas sweetening is also currently being used in enhanced oil recovery (EOR) in the United States (Beecy and Kuuskraa, 2005) where in these commercial EOR projects, a large fraction of the injected CO_2 is also retained underground (see Chapter 5).

Depending on the level of CO_2 in natural gas, different processes for natural gas sweetening (i.e., H_2S and CO_2 removal) are available (Kohl and Nielsen, 1997 and Maddox and Morgan, 1998):

- Chemical solvents
- Physical solvents
- Membranes

Natural gas sweetening using various alkanolamines (MEA, DEA, MDEA, etc.; See Table 3.2), or a mixture of them, is the most commonly used method. The process flow diagram for CO_2 recovery from natural gas is similar to what is presented for flue gas treatment (see Figure 3.4, Section 3.3.2.1), except that in natural gas processing, absorption occurs at high pressure, with subsequent expansion before the stripper column, where CO_2 will be flashed and separated. When the CO_2 concentration in natural gas is high, membrane systems may be more economical. Industrial application of membranes for recovery of CO_2 from natural gas started in the early 1980s for small units, with many design parameters unknown (Noble and Stern, 1995). It is now a well-established and competitive technology with advantages compared to other technologies, including amine treatment in certain cases (Tabe-Mohammadi, 1999). These advantages include lower capital cost, ease of skid-mounted installation, lower energy consumption, ability to be applied in remote areas, especially offshore and flexibility.

3.2.3 Steel production

The iron and steel industry is the largest energy-consuming manufacturing sector in the world, accounting for 10-15% of total industrial energy consumption (IEA GHG, 2000a). Associated CO_2 emissions were estimated at 1442 $MtCO_2$ in 1995. Two types of iron- and steel-making technologies are in operation today. The integrated steel plant has a typical capacity of 3-5 Mtonnes yr^{-1} of steel and uses coal as its basic fuel with, in many cases, additional natural gas and oil. The mini-mill uses electric arc furnaces to melt scrap with a typical output of 1 Mtonnes yr^{-1} of steel and an electrical consumption of 300-350 kWh $tonne^{-1}$ steel. Increasingly mini-mills blend direct-reduced iron (DRI) with scrap to increase steel quality. The production of direct-reduced iron involves reaction of high oxygen content iron ore with H_2 and CO to form reduced iron plus H_2O and CO_2. As a result, many of the direct reduction iron processes could capture a pure CO_2 stream.

An important and growing trend is the use of new iron-making processes, which can use lower grade coal than the coking coals required for blast furnace operation. A good example is the COREX process (von Bogdandy *et. al*, 1989), which produces a large additional quantity of N_2-free fuel gas which can be used in a secondary operation to convert iron ore to iron. Complete CO_2 capture from this process should be possible with this arrangement since the CO_2 and H_2O present in the COREX top gas must be removed to allow the CO plus H_2 to be heated and used to reduce iron oxide to iron in the secondary shaft kiln. This process will produce a combination of molten iron and iron with high recovery of CO_2 derived from the coal feed to the COREX process.

Table 3.2 Common solvents used for the removal of CO_2 from natural gas or shifted syngas in pre-combustion capture processes.

Solvent name	Type	Chemical name	Vendors
Rectisol	Physical	Methanol	Lurgi and Linde, Germany Lotepro Corporation, USA
Purisol	Physical	N-methyl-2-pyrolidone (NMP)	Lurgi, Germany
Selexol	Physical	Dimethyl ethers of polyethylene glycol (DMPEG)	Union Carbide, USA
Benfield	Chemical	Potassium carbonate	UOP
MEA	Chemical	Monoethanolamine	Various
MDEA	Chemical	Methyldiethylamine	BASF and others
Sulfinol	Chemical	Tetrahydrothiophene 1,1-dioxide (Sulfolane), an alkaloamine and water	Shell

Early opportunities exist for the capture of CO_2 emissions from the iron and steel industry, such as:

- CO_2 recovery from blast furnace gas and recycle of CO-rich top gas to the furnace. A minimum quantity of coke is still required and the blast furnace is fed with a mixture of pure O_2 and recycled top gas. The furnace is, in effect, converted from air firing to oxy-fuel firing with CO_2 capture (see Section 3.4). This would recover 70% of the CO_2 currently emitted from an integrated steel plant (Dongke et al., 1988). It would be feasible to retrofit existing blast furnaces with this process.
- Direct reduction of iron ore, using hydrogen derived from a fossil fuel in a pre-combustion capture step (see Section 3.5) (Duarte and Reich, 1998). Instead of the fuel being burnt in the furnace and releasing its CO_2 to atmosphere, the fuel would be converted to hydrogen and the CO_2 would be captured during that process. The hydrogen would then be used as a reduction agent for the iron ore. Capture rates should be 90-95% according to the design of the pre-combustion capture technique (see Section 3.5).

Other novel process routes for steel making to which CO_2 capture can be applied are currently in the research and development phase (Gielen, 2003; IEA, 2004)

3.2.4 *Cement production*

Emissions of CO_2 from the cement industry account for 6% of the total emissions of CO_2 from stationary sources (see Chapter 2). Cement production requires large quantities of fuel to drive the high temperature, energy-intensive reactions associated with the calcination of the limestone – that is calcium carbonate being converted to calcium oxide with the evolution of CO_2.

At present, CO_2 is not captured from cement plants, but possibilities do exist. The concentration of CO_2 in the flue gases is between 15-30% by volume, which is higher than in flue gases from power and heat production (3-15% by volume). So, in principle, the post-combustion technologies for CO_2 capture described in Section 3.3 could be applied to cement production plants, but would require the additional generation of steam in a cement plant to regenerate the solvent used to capture CO_2. Oxy-fuel combustion capture systems may also become a promising technique to recover CO_2 (IEA GHG, 1999). Another emerging option would be the use of calcium sorbents for CO_2 capture (see Sections 3.3.3.4 and 3.5.3.5) as calcium carbonate (limestone) is a raw material already used in cement plants. All of these capture techniques could be applied to retrofit, or new plant applications.

3.2.5 *Ammonia production*

CO_2 is a byproduct of ammonia (NH_3) production (Leites *et al.*, 2003); Two main groups of processes are used:

- Steam reforming of light hydrocarbons (natural gas, liquefied petroleum gas, naphtha)
- Partial oxidation or gasification of heavy hydrocarbons (coal, heavy fuel oil, vacuum residue).

Around 85% of ammonia is made by processes in the steam methane reforming group and so a description of the process is useful. Although the processes vary in detail, they all comprise the following steps:

1. Purification of the feed;
2. Primary steam methane reforming (see Section 3.5.2.1);
3. Secondary reforming, with the addition of air, commonly called auto thermal reforming (see Section 3.5.2.3);
4. Shift conversion of CO and H_2O to CO_2 and H_2;
5. Removal of CO_2;
6. Methanation (a process that reacts and removes trace CO and CO_2);
7. Ammonia synthesis.

The removal of CO_2 as a pure stream is of interest to this report. A typical modern plant will use the amine solvent process to treat 200,000 $Nm^3\ h^{-1}$ of gas from the reformer, to produce 72 tonnes h^{-1} of concentrated CO_2 (Apple, 1997). The amount of CO_2 produced in modern plants from natural gas is about 1.27 tCO_2/tNH_3. Hence, with a world ammonia production of about 100 Mtonnes yr^{-1}, about 127 $MtCO_2\ yr^{-1}$ is produced. However, it should be noted that this is not all available for storage, as ammonia plants are frequently combined with urea plants, which are capable of utilizing 70-90% of the CO_2. About 0.7 $MtCO_2\ yr^{-1}$ captured from ammonia plants is currently used for enhanced oil recovery in the United States (Beecy and Kuuskraa, 2005) with a large fraction of the injected CO_2 being retained underground (see Chapter 5) in these commercial EOR projects.

3.2.6 *Status and outlook*

We have reviewed processes – current and potential - that may be used to separate CO_2 in the course of producing another product. One of these processes, natural gas sweetening, is already being used in two industrial plants to capture and store about 2 $MtCO_2\ yr^{-1}$ for the purpose of climate change mitigation. In the case of ammonia production, pure CO_2 is already being separated. Over 7 $MtCO_2\ yr^{-1}$ captured from both natural gas sweetening and ammonia plants is currently being used in enhanced oil recovery with some storage (see also Chapter 5) of the injected CO_2 in these commercial EOR projects. Several potential processes for CO_2 capture in steel and cement production exist, but none have yet been applied. Although the total amount of CO_2 that may be captured from these industrial processes is insignificant in terms of the scale of the climate change challenge, significance may arise in that their use could serve as early examples of solutions that can be applied on larger scale elsewhere.

3.3 Post-combustion capture systems

3.3.1 *Introduction*

Current anthropogenic CO_2 emissions from stationary sources come mostly from combustion systems such as power plants, cement kilns, furnaces in industries and iron and steel production plants (see Chapter 2). In these large-scale processes, the direct firing of fuel with air in a combustion chamber has been (for centuries, as it is today) the most economic technology to extract and use the energy contained in the fuel. Therefore, the strategic importance of post-combustion capture systems becomes evident when confronted with the reality of today's sources of CO_2 emissions. Chapter 2 shows that any attempt to mitigate CO_2 emissions from stationary sources on a relevant scale using CO_2 capture and storage, will have to address CO_2 capture from combustion systems. All the CO_2 capture systems described in this section are aimed at the separation of CO_2 from the flue gases generated in a large-scale combustion process fired with fossil fuels. Similar capture systems can also be applied to biomass fired combustion processes that tend to be used on a much smaller scale compared to those for fossil fuels.

Flue gases or stack gases found in combustion systems are usually at atmospheric pressure. Because of the low pressure, the large presence of nitrogen from air and the large scale of the units, huge flows of gases are generated, the largest example of which may be the stack emissions coming from a natural gas combined cycle power plant having a maximum capacity of around 5 million normal $m^3\ h^{-1}$. CO_2 contents of flue gases vary depending on the type of fuel used (between 3% for a natural gas combined cycle to less than 15% by volume for a coal-fired combustion plant See Table 2.1). In principle post-combustion capture systems can be applied to flue gases produced from the combustion of any type of fuel. However, the impurities in the fuel are very important for the design and costing of the complete plant (Rao and Rubin, 2002). Flue gases coming from coal combustion will contain not only CO_2, N_2, O_2 and H_2O, but also air pollutants such as SO_x, NO_x, particulates, HCl, HF, mercury, other metals and other trace organic and inorganic contaminants. Figure 3.3 shows a general schematic of a coal-fired power plant in which additional unit operations are deployed to remove the air pollutants prior to CO_2 capture in an absorption-based process. Although capture of CO_2 in these flue gases is in principle more problematic and energy intensive than from other gas streams, commercial experience is available at a sufficiently large scale (see Section 3.3.2) to provide the basis for cost estimates for post-combustion CO_2 capture systems (see Section 3.7). Also, a large R&D effort is being undertaken worldwide to develop more efficient and lower cost post-combustion systems (see Section 3.3.3), following all possible approaches for the CO_2 separation step (using sorbents, membranes or cryogenics; see Section 3.1.3).

3.3.2 *Existing technologies*

There are several commercially available process technologies which can in principle be used for CO_2 capture from flue gases. However, comparative assessment studies (Hendriks, 1994; Riemer and Ormerod, 1995; IEA GHG, 2000b) have shown that absorption processes based on chemical solvents are currently the preferred option for post-combustion CO_2 capture. At this point in time, they offer high capture efficiency and selectivity, and the lowest energy use and costs when compared with other existing post-combustion capture processes. Absorption processes have reached the commercial stage of operation for post-combustion CO_2 capture systems, albeit not on the scale required for power plant flue gases. Therefore, the following paragraphs are devoted to a review of existing knowledge of the technology and the key technical and environmental issues relevant to the application of this currently leading commercial option for CO_2 capture. The fundamentals of the CO_2 separation step using commercial chemical absorption processes are discussed first. The requirements of flue gas pretreatment (removal of pollutants other than CO_2) and the energy requirements for regeneration of the chemical solvent follow.

3.3.2.1 *Absorption processes*

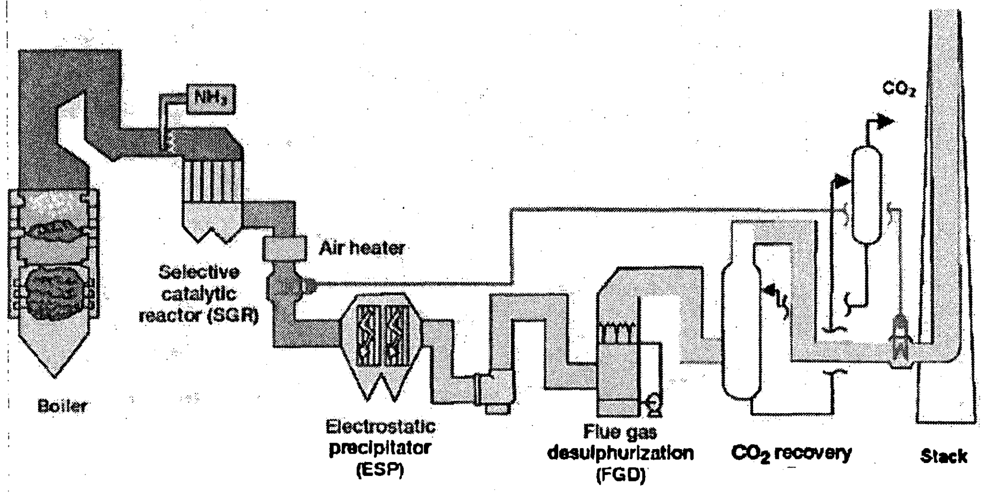


Figure 3.3 Schematic of a pulverized coal-fired power plant with an amine-based CO_2 capture system and other emission controls.

Absorption processes in post-combustion capture make use of the reversible nature of the chemical reaction of an aqueous alkaline solvent, usually an amine, with an acid or sour gas. The process flow diagram of a commercial absorption system is presented in Figure 3.4. After cooling the flue gas, it is brought into contact with the solvent in the absorber. A blower is required to overcome the pressure drop through the absorber. At absorber temperatures typically between 40 and 60°C, CO_2 is bound by the chemical solvent in the absorber. The flue gas then undergoes a water wash section to balance water in the system and to remove any solvent droplets or solvent vapour carried over, and then it leaves the absorber. It is possible to reduce CO_2 concentration in the exit gas down to very low values, as a result of the chemical reaction in the solvent, but lower exit concentrations tend to increase the height of the absorption vessel. The 'rich' solvent, which contains the chemically bound CO_2 is then pumped to the top of a stripper (or regeneration vessel), via a heat exchanger. The regeneration of the chemical solvent is carried out in the stripper at elevated temperatures (100°C–140°C) and pressures not very much higher than atmospheric pressure. Heat is supplied to the reboiler to maintain the regeneration conditions. This leads to a thermal energy penalty as a result of heating up the solvent, providing the required desorption heat for removing the chemically bound CO_2 and for steam production which acts as a stripping gas. Steam is recovered in the condenser and fed back to the stripper, whereas the CO_2 product gas leaves the stripper. The 'lean' solvent, containing far less CO_2 is then pumped back to the absorber via the lean-rich heat exchanger and a cooler to bring it down to the absorber temperature level.

Figure 3.4 also shows some additional equipment needed to maintain the solution quality as a result of the formation of degradation products, corrosion products and the presence of particles. This is generally done using filters, carbon beds and a thermally operated reclaimer. Control of degradation and corrosion has in fact been an important aspect in the development of absorption processes over the past few decades.

The key parameters determining the technical and economic operation of a CO_2 absorption system are:

- *Flue gas flow rate* - The flue gas flow rate will determine the size of the absorber and the absorber represents a sizeable contribution to the overall cost.
- *CO_2 content in flue gas* - Since flue gas is usually at atmospheric pressure, the partial pressure of CO_2 will be as low as 3-15 kPa. Under these low CO_2 partial pressure conditions, aqueous amines (chemical solvents) are the most suitable absorption solvents (Kohl and Nielsen, 1997).
- *CO_2 removal* - In practice, typical CO_2 recoveries are between 80% and 95%. The exact recovery choice is an economic trade-off, a higher recovery will lead to a taller absorption column, higher energy penalties and hence increased costs.
- *Solvent flow rate* - The solvent flow rate will determine the size of most equipment apart from the absorber. For a given solvent, the flow rate will be fixed by the previous parameters and also the chosen CO_2 concentrations within the lean and the rich solutions.
- *Energy requirement* - The energy consumption of the process is the sum of the thermal energy needed to regenerate the solvents and the electrical energy required to operate liquid pumps and the flue gas blower or fan. Energy is also required to compress the CO_2 recovered to the final pressure required for transport and storage.

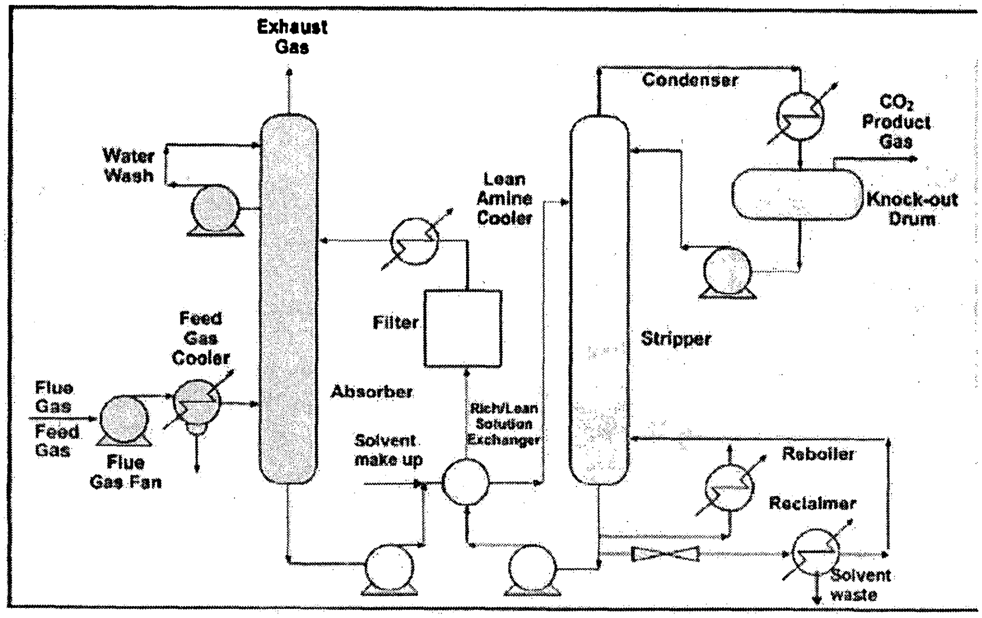


Figure 3.4 Process flow diagram for CO_2 recovery from flue gas by chemical absorption.

- Cooling requirement - Cooling is needed to bring the flue gas and solvent temperatures down to temperature levels required for efficient absorption of CO_2. Also, the product from the stripper will require cooling to recover steam from the stripping process.

The purity and pressure of CO_2 typically recovered from an amine-based chemical absorption process are as follows (Sander and Mariz, 1992):

- CO_2 purity: 99.9% by volume or more (water saturated conditions)
- CO_2 pressure: 50 kPa (gauge)

A further CO_2 purification step makes it possible to bring the CO_2-quality up to food-grade standard. This is required for use in beverages and packaging.

Since combustion flue gases are generally at atmospheric pressure and the CO_2 is diluted, the CO_2 partial pressure is very low. Also, flue gas contains oxygen and other impurities; therefore an important characteristic of an absorption process is in the proper choice of solvent for the given process duty. High CO_2 loading and low heat of desorption energy are essential for atmospheric flue gas CO_2 recovery. The solvents must also have low byproduct formation and low decomposition rates, to maintain solvent performance and to limit the amount of waste materials produced. The important effect of other contaminants on the solvent is discussed in Section 3.3.2.2.

The following three absorption processes are commercially available for CO_2 capture in post-combustion systems:

- The Kerr-McGee/ABB Lummus Crest Process (Barchas and Davis, 1992) - This process recovers CO_2 from coke and coal-fired boilers, delivering CO_2 for soda ash and liquid CO_2 preparations. It uses a 15-20% by weight aqueous MEA (Mono-Ethanolamine) solution. The largest capacity experienced for this process is 800 tCO_2 d^{-1}utilizing two parallel trains (Arnold *et al.*, 1982).
- The Fluor Daniel ® ECONAMINE™ Process (Sander and Mariz, 1992, Chapel *et al.*, 1999) - This process was acquired by Fluor Daniel Inc. from Dow Chemical Company in 1989. It is a MEA-based process (30% by weight aqueous solution) with an inhibitor to resist carbon steel corrosion and is specifically tailored for oxygen-containing gas streams. It has been used in many plants worldwide recovering up to 320 tCO_2 d^{-1} in a single train for use in beverage and urea production.
- The Kansai Electric Power Co., Mitsubishi Heavy Industries, Ltd., KEPCO/MHI Process (Mimura *et al.*, 1999 and 2003) - The process is based upon sterically-hindered amines and already three solvents (KS-1, KS-2 and KS-3) have been developed. KS-1 was commercialized in a urea production application. In this process, low amine losses and low solvent degradation have been noted without the use of inhibitors or additives. As shown in Figure 3.5, the first commercial plant at 200 tCO_2 d^{-1} recovery from a flue gas stream has been operating in Malaysia since 1999 for urea production (equivalent to the emissions from a 10 MWt coal-fired power plant)

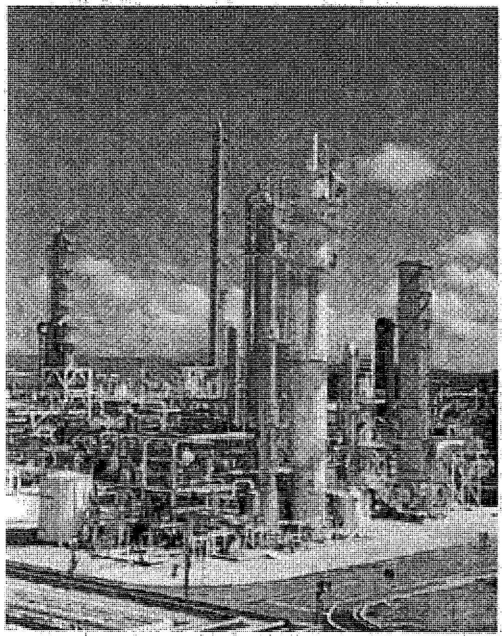


Figure 3.5 CO_2 capture plant in Malaysia using a 200 tonne d^{-1} KEPCO/MHI chemical solvent process (Courtesy of Mitsubishi).

The performance of the chemical solvent in the operation is maintained by replacement, filtering and reclaiming, which leads to a consumables requirement. Typical values for the solvent consumption are between 0.2 and 1.6 kg/tCO2. In addition, chemicals are needed to reclaim the amine from the heat stable salt (typically 0.03–0.13 kg NaOH/tCO2) and to remove decomposition products (typically 0.03-0.06 kg activated carbon/tCO2). The ranges are primarily dependent on the absorption process, with KS-1 being at the low end of the range and ECONAMINE ™ at the high end.

3.3.2.2. Flue gas pretreatment

Flue gases from a combustion power plant are usually above 100°C, which means that they need to be cooled down to the temperature levels required for the absorption process. This can be done in a cooler with direct water contact, which also acts as a flue gas wash with additional removal of fine particulates.

In addition to the above, flue gas from coal combustion will contain other acid gas components such as NO_x and SO_x. Flue gases from natural gas combustion will normally only contain NO_x. These acidic gas components will, similar to CO_2, have a chemical interaction with the alkaline solvent. This is not desirable as the irreversible nature of this interaction leads to the formation of heat stable salts and hence a loss in absorption capacity of the solvent and the risk of formation of solids in the solution. It also results in an extra consumption of chemicals to regenerate the solvent and the production of a waste stream such as sodium sulphate or sodium nitrate. Therefore, the pre-removal of NO_x and SO_x to very low values before CO_2

recovery becomes essential. For NO_x it is the NO_2 which leads to the formation of heat stable salts. Fortunately, the level of NO_2 is mostly less than 10% of the overall NO_x content in a flue gas (Chapel *et al.*, 1999).

The allowable SO_x content in the flue gas is primarily determined by the cost of the solvent - as this is consumed by reaction with SO_x. SO_2 concentrations in the flue gas are typically around 300-5000 ppm. Commercially available SO_2-removal plants will remove up to 98-99%. Amines are relatively cheap chemicals, but even cheap solvents like MEA (with a price around 1.25 US$ kg^{-1} (Rao and Rubin, 2002) may require SO_x concentrations of around 10 ppm, to keep solvent consumption (around 1.6 kg of MEA/tCO_2 separated) and make up costs at reasonable values, which often means that additional flue gas desulphurization is needed. The optimal SO_2 content, before the CO_2 absorption process is a cost trade-off between CO_2-solvent consumption and SO_2-removal costs. For the Kerr-Mcgee/ABB Lummus Crest Technology, SO_2-removal is typically not justified for SO_2 levels below 50 ppm (Barchas and Davis, 1992). For the Fluor Daniel Econamine FG process a maximum of 10 ppm SO_2 content is generally set as the feed gas specification (Sander and Mariz, 1992). This can be met by using alkaline salt solutions in a spray scrubber (Chapel *et al.*, 1999). A SO_2 scrubber might also double as a direct contact cooler to cool down the flue gas.

Careful attention must also be paid to fly ash and soot present in the flue gas, as they might plug the absorber if contaminants levels are too high. Often the requirements of other flue gas treatment are such that precautions have already been taken. In the case of CO_2 recovery from a coal-fired boiler flue gas, the plant typically has to be equipped with a DeNO_x unit, an electrostatic precipitator or a bag house filter and a DeSO_x or flue gas desulphurization unit as part of the environmental protection of the power plant facilities. In some cases, these environmental protection facilities are not enough to carry out deep SO_x removal up to the 1-2 ppm level sometimes needed to minimize solvent consumption and its reclamation from sticking of solvent wastes on reclaimer tube surfaces.

3.3.2.3 Power generation efficiency penalty in CO_2 capture

A key feature of post-combustion CO_2 capture processes based on absorption is the high energy requirement and the resulting efficiency penalty on power cycles. This is primarily due to the heat necessary to regenerate the solvent, steam use for stripping and to a lesser extent the electricity required for liquid pumping, the flue gas fan and finally compression of the CO_2 product. Later in this chapter, Sections 3.6 and 3.7 present summaries of CO_2 capture energy requirements for a variety of power systems and discuss the environmental and economic implications of these energy demands.

In principle, the thermal energy for the regeneration process can be supplied by an auxiliary boiler in a retrofit situation. Most studies, however, focus on an overall process in which the absorption process is integrated into the power plant. The heat requirement is at such levels that low-pressure steam, for example condensing at 0.3 MPa(g), can be used in the reboiler. The steam required for the regeneration process is then extracted from the steam cycle in the power plant. For a coal-fired power station, low-pressure steam will be extracted prior to the last expansion stage of the steam turbine. For a natural gas fired combined cycle, low-pressure steam will be extracted from the last stage in the heat recovery steam generator. Some of this heat can be recovered by preheating the boiler feed water (Hendriks, 1994). Values for the heat requirement for the leading absorption technologies are between 2.7 and 3.3 GJ/tCO_2, depending on the solvent process. Typical values for the electricity requirement are between 0.06 and 0.11 GJ/tCO_2 for post-combustion capture in coal- fired power plants and 0.21 and 0.33 GJ/tCO_2 for post-combustion capture in natural gas fired combined cycles. Compression of the CO_2 to 110 bar will require around 0.4 GJ/tCO_2 (IEA GHG, 2004).

Integration of the absorption process with an existing power plant will require modifications of the low-pressure part of the steam cycle, as a sizeable fraction of the steam will be extracted and hence will not be available to produce power (Nsakala *et al.*, 2001, Mimura *et al.*,1995, Mimura *et al.*, 1997). To limit the required modifications, small back-pressure steam turbines using medium pressure steam to drive the flue gas fan and boiler feed water pumps can be used. The steam is then condensed in the reboiler (Mimura *et al.*, 1999). Furthermore, in power plants based on steam cycles more than 50% thermal energy in the steam cycle is disposed off in the steam condenser. If the steam cycle system and CO_2 recovery can be integrated, part of the waste heat disposed by the steam condenser can be utilized for regeneration of the chemical solvent.

The reduction of the energy penalty is, nevertheless, closely linked to the chosen solvent system. The IEA Greenhouse Programme (IEA GHG) has carried out performance assessments of power plants with post-combustion capture of CO_2, taking into consideration the most recent improvements in post-combustion CO_2 capture processes identified by technology licensors (IEA GHG, 2004). In this study, Mitsui Babcock Energy Ltd. and Alstom provided information on the use of a high efficiency, ultra-supercritical steam cycle (29 MPa, 600°C, 620°C reheat) boiler and steam turbine for a coal-fired power plant, while for the NGCC case, a combined cycle using a GE 9FA gas turbine was adopted. Fluor provided information on the Fluor Econamine + process based on MEA, and MHI provided information on KEPCO/MHI process based on the KS-1 solvent for CO_2 capture. CO_2 leaving these systems were compressed to a pressure of 11 MPa. The overall net power plant efficiencies with and without CO_2 capture are shown in Figure 3.6, while Figure 3.7 shows the efficiency penalty for CO_2 capture. Overall, results from this study show that the efficiency penalty for post-combustion capture in coal and gas fired plant is lower for KEPCO/MHI's CO_2 absorption process. For the purpose of comparison, the performance of power plants with pre-combustion and oxy-fuel capture, based on the same standard set of plant design criteria are also shown in Figures 3.6 and 3.7.

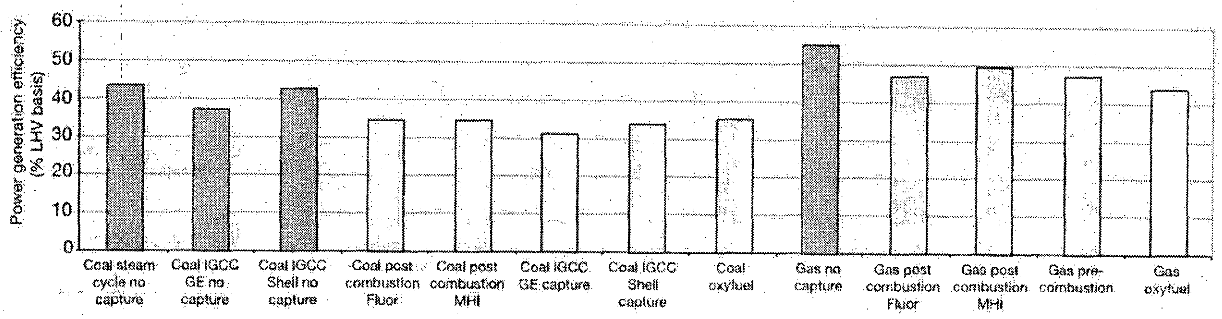


Figure 3.6 Thermal efficiencies of power plants with and without CO_2 capture, % LHV-basis (Source data: Davison 2005, IEA GHG 2004, IEA GHG 2003; IEA GHG, 2000b; Dillon *et al.*, 2005).

a. The efficiencies are based on a standard set of plant design criteria (IEA GHG, 2004).
b. The coal steam cycle plants, including the post-combustion capture and oxy-fuel plants, are based on ultra-supercritical steam (29MPa, 600C superheat, 620C reheat). The IGCC and natural gas pre- and post-combustion capture plants are based on GE 9FA gas turbine combined cycles. The natural gas oxy-fuel plant is based on a CO_2 recycle gas turbine, as shown in Figure 3.10, with different operating pressures and temperatures but similar mechanical design criteria to that of the 9FA.
c. Data are presented for two types of post-combustion capture solvent: MEA (Fluor plant designs) and KS-1 (MHI plant designs). The solvent desorption heat consumptions are 3.2 and 2.7 MJ/kgCO_2 captured respectively for the coal plants and 3.7 and 2.7 MJ kg^{-1} for the natural gas plants.
d. Data are presented for IGCC plants based on two types of gasifier: the Shell dry feed/heat recovery boiler type and the GE (formerly Texaco) slurry feed water quench type.
e. The natural gas pre-combustion capture plant is based on partial oxidation using oxygen.
f. The oxy-fuel plants include cryogenic removal of some of the impurities from the CO_2 during compression. Electricity consumption for oxygen production by cryogenic distillation of air is 200 kWh/ tO_2 at atmospheric pressure for the coal plant and 320 kWh/ tO_2 at 40 bar for the natural gas plant. Oxygen production in the IGCC and natural gas pre-combustion capture plants is partially integrated with the gas turbine compressor, so comparable data cannot be provided for these plants.
g. The percentage CO_2 capture is 85–90% for all plants except the natural gas oxy-fuel plant which has an inherently higher percentage capture of 97%.

3.3.2.4 Effluents

As a result of decomposition of amines, effluents will be created, particularly ammonia and heat-stable salts. Rao and Rubin (2002) have estimated these emissions for an MEA-based process based on limited data. In such processes, heat stable salts (solvent decomposition products, corrosion products etc.) are removed from the solution in a reclaimer and a waste stream is created and is disposed of using normal HSE (Health, Safety and Environmental) practices. In some cases, these reclaimer bottoms may be classified as a hazardous waste, requiring special handling (Rao and Rubin, 2002). Also a particle filter and carbon filter is normally installed in the solvent circuit to remove byproducts. Finally, some solvent material will be lost to the environment through evaporation and carry over in the absorber, which is accounted for in the solvent consumption. It is expected that acid gases other than CO_2, which are still present in the flue gas (SO_x and NO_2) will also be absorbed in the solution. This will lower the concentration of these components further and even the net emissions in some cases depending on the amount of additional energy use for CO_2 capture (see Tables 3.4 and 3.5). As SO_2-removal prior to CO_2-removal is very likely in coal-fired plants, this will lead to the production of a waste or byproduct stream containing gypsum and water from the FGD unit.

3.3.3 Emerging technologies

3.3.3.1 Other absorption process

Various novel solvents are being investigated, with the object of achieving a reduced energy consumption for solvent regeneration (Chakma, 1995; Chakma and Tontiwachwuthikul, 1999; Mimura *et al.*, 1999; Zheng *et al.*, 2003; Cullinane and Rochelle, 2003; Leites, 1998; Erga *et al.*, 1995; Aresta and Dibenedetto, 2003; Bai and Yeh, 1997).

Besides novel solvents, novel process designs are also currently becoming available (Leites *et al.* 2003). Research is also being carried out to improve upon the existing practices and packing types (Aroonwilas *et al.*, 2003). Another area of research is to increase the concentration levels of aqueous MEA solution used in absorption systems as this tends to reduce the size of equipment used in capture plants (Aboudheir *et al.*, 2003). Methods to prevent oxidative degradation of MEA by de-oxygenation of the solvent solutions are also being investigated (Chakravarti *et al.*, 2001). In addition to this, the catalytic removal of oxygen in flue gases from coal firing has been suggested (Nsakala *et al.*, 2001) to enable operation with promising solvents sensitive to oxygen.

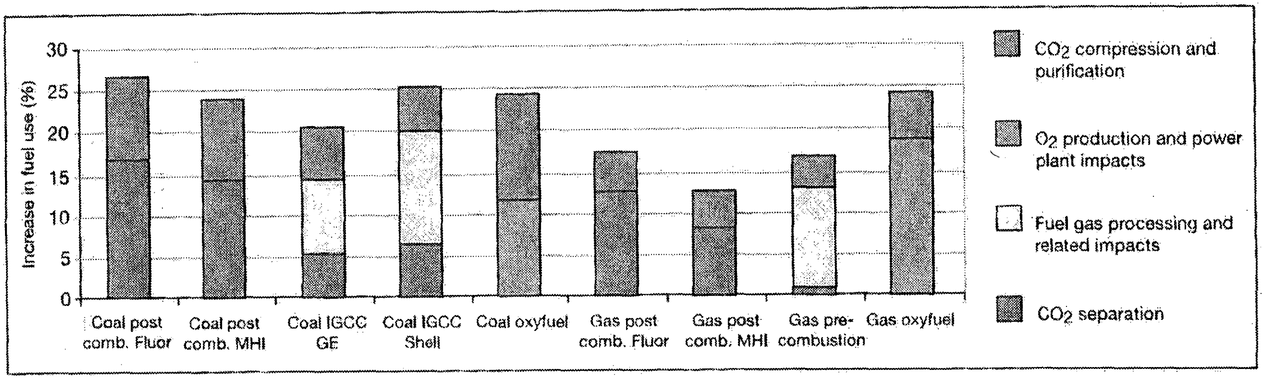


Figure 3.7 Percentage increase in fuel use per kWh of electricity due to CO_2 capture, compared to the same plant without capture (Source data: Davison, 2005; IEA GHG, 2004; IEA GHG, 2003; IEA GHG, 2000b; Dillon *et al.*, 2005).

a. The increase in fuel required to produce a kWh of electricity is calculated by comparing the same type of plant with and without capture. The increase in fuel consumption depends on the type of baseline plant without capture. For example, the increase in energy consumption for a GE IGCC plant with capture compared to a coal steam cycle baseline plant without capture would be 40% as opposed to the lower value shown in the figure that was calculated relative to the same type of baseline plant without capture.

b. The direct energy consumptions for CO_2 separation are lower for pre-combustion capture than for post-combustion capture, because CO_2 is removed from a more concentrated, higher pressure gas, so a physical rather than a chemical solvent can be used.

c. The 'Fuel gas processing and related impacts' category for IGCC includes shift conversion of the fuel gas and the effects on the gas turbine combined cycle of removal of CO_2 from the fuel gas and use of hydrogen as a fuel instead of syngas. For natural gas pre-combustion capture this category also includes partial oxidation/steam reforming of the natural gas.

d. The energy consumption for CO_2 compression is lower in pre-combustion capture than in post-combustion capture because some of the CO_2 leaves the separation unit at elevated pressure.

e. The energy consumption for CO_2 compression in the oxy-fuel processes depends on the composition of the extracted product, namely 75% by volume in the coal-fired plant and 93% by volume in the gas fired plant. Impurities are cryogenically removed from the CO_2 during compression, to give a final CO_2 purity of 96% by volume. The energy consumption of the cryogenic CO_2 separation unit is included in the CO_2 compression power consumption.

f. The 'Oxygen production and power plant impacts' category for oxy-fuel processes includes the power consumption for oxygen production and the impacts of CO_2 capture on the rest of the power plant, that is excluding CO_2 compression and purification. In the coal-fired oxy-fuel plant, the efficiency of the rest of the power plant increases slightly, for example due to the absence of a flue gas desulphurization (FGD) unit. The efficiency of the rest of the gas fired oxy-fuel plant decreases because of the change of working fluid in the power cycle from air to recycled flue gas.

3.3.3.2 *Adsorption process*

In the adsorption process for flue gas CO_2 recovery, molecular sieves or activated carbons are used in adsorbing CO_2. Desorbing CO_2 is then done by the pressure swing operation (PSA) or temperature swing operation (TSA). Most applications are associated with pressure swing adsorption (Ishibashi *et al.*, 1999 and Yokoyama, 2003). Much less attention has been focused on CO_2 removal via temperature swing adsorption, as this technique is less attractive compared to PSA due to the longer cycle times needed to heat up the bed of solid particles during sorbent regeneration. For bulk separations at large scales, it is also essential to limit the length of the unused bed and therefore opt for faster cycle times.

Adsorption processes have been employed for CO_2 removal from synthesis gas for hydrogen production (see Section 3.5.2.9). It has not yet reached a commercial stage for CO_2 recovery from flue gases. The following main R&D activities have been conducted:

- Study of CO_2 removal from flue gas of a thermal power plant by physical adsorption (Ishibashi *et al.*, 1999);
- Study of CO_2 removal from flue gas of a thermal power plant by a combined system with pressure swing adsorption and a super cold separator (Takamura *et al.*, 1999);
- Pilot tests on the recovery of CO_2 from a coal and oil fired power plant, using pressure temperature swing adsorption (PTSA) and an X-type zeolite as an adsorbent (Yokoyama, 2003).

Pilot test results of coal-fired flue gas CO_2 recovery by adsorption processes show that the energy consumption for capture (blowers and vacuum pumps) has improved from the original 708 kWh/tCO_2 to 560 kWh/tCO_2. An energy consumption of 560 kWh/tCO_2 is equivalent to a loss corresponding to 21% of the energy output of the power plant. Recovered CO_2 purity is about 99.0% by volume using two stages of a PSA and PTSA system (Ishibashi *et al.*, 1999).

It can be concluded that based on mathematical models and data from pilot-scale experimental installations, the design of a full-scale industrial adsorption process might be feasible. A serious drawback of all adsorptive methods is the necessity to treat the gaseous feed before CO_2 separation in an adsorber. Operation at high temperature with other sorbents (see Section 3.3.3.4) can circumvent this requirement (Sircar and Golden, 2001). In many cases gases have to be also cooled and dried, which limits the attractiveness of PSA, TSA or ESA (electric swing adsorption) vis-à-vis capture by chemical absorption described in previous sections. The development of a new generation of materials that would efficiently adsorb CO_2 will undoubtedly enhance the competitiveness of adsorptive separation in a flue gas application.

3.3.3.3 Membranes

Membrane processes are used commercially for CO_2 removal from natural gas at high pressure and at high CO_2 concentration (see Section 3.2.2). In flue gases, the low CO_2 partial pressure difference provides a low driving force for gas separation. The removal of carbon dioxide using commercially available polymeric gas separation membranes results in higher energy penalties on the power generation efficiency compared to a standard chemical absorption process (Herzog *et al.*, 1991, Van der Sluijs *et al.*, 1992 and Feron, 1994). Also, the maximum percentage of CO_2 removed is lower than for a standard chemical absorption processes. Improvements can be made if more selective membranes become available, such as facilitated membranes, described below.

The membrane option currently receiving the most attention is a hybrid membrane – absorbent (or solvent) system. These systems are being developed for flue gas CO_2 recovery. Membrane/solvent systems employ membranes to provide a very high surface area to volume ratio for mass exchange between a gas stream and a solvent resulting in a very compact system. This results in a membrane contactor system in which the membrane forms a gas permeable barrier between a liquid and a gaseous phase. In general, the membrane is not involved in the separation process. In the case of porous membranes, gaseous components diffuse through the pores and are absorbed by the liquid; in cases of non-porous membranes they dissolve in the membrane and diffuse through the membrane. The contact surface area between gas and liquid phase is maintained by the membrane and is independent of the gas and liquid flow rate. The selectivity of the partition is primarily determined by the absorbent (solvent). Absorption in the liquid phase is determined either by physical partition or by a chemical reaction.

The advantages of membrane/solvent systems are avoidance of operational problems occurring in conventional solvent absorption systems (see Section 3.3.2.1) where gas and liquid flows are in direct contact. Operational problems avoided include foaming, flooding entrainment and channelling, and result in the free choice of the gas and liquid flow rates and a fixed interface for mass transfer in the membrane/solvent system. Furthermore, the use of compact membranes result in smaller equipment sizes with capital cost reductions. The choice of a suitable combination of solvent and membrane material is very important. The material characteristics should be such that the transfer of solvent through the membrane is avoided at operating pressure gradients of typically 50–100 kPa, while the transfer of gas is not hindered. The overall process configuration in terms of unit operations would be very similar to a conventional chemical absorption/desorption process (see Figure 3.4). Membrane/solvent systems can be both used in the absorption as well as in the desorption step. Feron and Jansen (2002) and Falk-Pedersen *et al.* (1999) give examples of suitable membrane/solvent systems.

Research and development efforts have also been reported in the area of facilitated transport membranes. Facilitated transport membranes rely on the formation of complexes or reversible chemical reactions of components present in a gas stream with compounds present in the membrane. These complexes or reaction products are then transported through the membrane. Although solution and diffusion still play a role in the transport mechanism, the essential element is the specific chemical interaction of a gas component with a compound in the membrane, the so-called carrier. Like other pressure driven membrane processes, the driving force for the separation comes from a difference in partial pressure of the component to be transported. An important class of facilitated transport membranes is the so-called supported liquid membrane in which the carrier is dissolved into a liquid contained in a membrane. For CO_2 separations, carbonates, amines and molten salt hydrates have been suggested as carriers (Feron, 1992). Porous membranes and ion-exchange membranes have been employed as the support. Until now, supported liquid membranes have only been studied on a laboratory scale. Practical problems associated with supported liquid membranes are membrane stability and liquid volatility. Furthermore, the selectivity for a gas decreases with increasing partial pressure on the feed side. This is a result of saturation of the carrier in the liquid. Also, as the total feed pressure is increased, the permeation of unwanted components is increased. This also results in a decrease in selectivity. Finally, selectivity is also reduced by a reduction in membrane thickness. Recent development work has focused on the following technological options that are applicable to both CO_2/N_2 and CO_2/H_2 separations:

- Amine-containing membranes (Teramoto *et al.*, 1996);
- Membranes containing potassium carbonate polymer gel membranes (Okabe *et al.*, 2003);
- Membranes containing potassium carbonate-glycerol (Chen *et al.*, 1999);
- Dendrimer-containing membranes (Kovvali and Sirkar, 2001).
- Poly-electrolyte membranes (Quinn and Laciak, 1997);

Facilitated transport membranes and other membranes can also be used in a preconcentration step prior to the liquefaction of CO_2 (Mano *et al.*, 2003).

3.3.3.4 Solid sorbents

There are post-combustion systems being proposed that make use of regenerable solid sorbents to remove CO_2 at relatively high temperatures. The use of high temperatures in the CO_2 separation step has the potential to reduce efficiency penalties with respect to wet-absorption methods. In principle, they all follow the scheme shown in Figure 3.2a, where the combustion flue gas is put in contact with the sorbent in a suitable reactor to allow the gas-solid reaction of CO_2 with the sorbent (usually the carbonation of a metal oxide). The solid can be easily separated from the gas stream and sent for regeneration in a different reactor. Instead of moving the solids, the reactor can also be switched between sorption and regeneration modes of operation in a batch wise, cyclic operation. One key component for the development of these systems is obviously the sorbent itself, that has to have good CO_2 absorption capacity and chemical and mechanical stability for long periods of operation in repeated cycles. In general, sorbent performance and cost are critical issues in all post-combustion systems, and more elaborate sorbent materials are usually more expensive and will have to demonstrate outstanding performance compared with existing commercial alternatives such as those described in 3.3.2.

Solid sorbents being investigated for large-scale CO_2 capture purposes are sodium and potassium oxides and carbonates (to produce bicarbonate), usually supported on a solid substrate (Hoffman *et al.*, 2002; Green *et al.*, 2002). Also, high temperature Li-based and CaO-based sorbents are suitable candidates. The use of lithium-containing compounds (lithium, lithium-zirconia and lithium-silica oxides) in a carbonation-calcination cycle, was first investigated in Japan (Nakagawa and Ohashi, 1998). The reported performance of these sorbents is very good, with very high reactivity in a wide range of temperatures below 700°C, rapid regeneration at higher temperatures and durability in repeated capture-regeneration cycles. This is essential because lithium is an intrinsically expensive material.

The use of CaO as a regenerable CO_2 sorbent has been proposed in several processes dating back to the 19th century. The carbonation reaction of CaO to separate CO_2 from hot gases ($T > 600$°C) is very fast and the regeneration of the sorbent by calcining the $CaCO_3$ into CaO and pure CO_2 is favoured at $T > 900$°C (at a partial pressure of CO_2 of 0.1 MPa). The basic separation principle using this carbonation-calcination cycle was successfully tested in a pilot plant (40 tonne d^{-1}) for the development of the Acceptor Coal Gasification Process (Curran *et al.*, 1967) using two interconnected fluidized beds. The use of the above cycle for a post-combustion system was first proposed by Shimizu *et al.* (1999) and involved the regeneration of the sorbent in a fluidized bed, firing part of the fuel with O_2/CO_2 mixtures (see also Section 3.4.2). The effective capture of CO_2 by CaO has been demonstrated in a small pilot fluidized bed (Abanades *et al.*, 2004a). Other combustion cycles incorporating capture of CO_2 with CaO that might not need O_2 are being developed, including one that works at high pressures with simultaneous capture of CO_2 and SO_2 (Wang *et al.*, 2004). One weak point in all these processes is that natural sorbents (limestones and dolomites) deactivate rapidly, and a large make-up flow of sorbent (of the order of the mass flow of fuel entering the plant) is required to maintain the activity in the capture-regeneration loop (Abanades *et al.*, 2004b). Although the deactivated sorbent may find application in the cement industry and the sorbent cost is low, a range of methods to enhance the activity of Ca-based CO_2 sorbents are being pursued by several groups around the world.

3.3.4 *Status and outlook*

Virtually all the energy we use today from carbon-containing fuels is obtained by directly burning fuels in air. This is despite many decades of exploring promising and more efficient alternative energy conversion cycles that rely on other fuel processing steps prior to fuel combustion or avoiding direct fuel combustion (see pre-combustion capture – Section 3.5). In particular, combustion-based systems are still the competitive choice for operators aiming at large-scale production of electricity and heat from fossil fuels, even under more demanding environmental regulations, because these processes are reliable and well proven in delivering electricity and heat at prices that often set a benchmark for these services. In addition, there is a continued effort to raise the energy conversion efficiencies of these systems through advanced materials and component development. This will allow these systems to operate at higher temperature and higher efficiency.

As was noted in Section 3.1, the main systems of reference for post-combustion capture are the present installed capacity of coal and natural gas power plants, with a total of 970 GW_e subcritical steam and 155 GW_e of supercritical/ultra-supercritical steam-based pulverized coal fired plants, 339 GW_e of natural gas combined cycle, 333 GW_e natural gas steam-electric power plants and 17 GW_e of coal-fired, circulating, fluidized-bed combustion (CFBC) power plants. An additional capacity of 454 GW_e of oil-based power plant, with a significant proportion of these operating in an air-firing mode is also noted (IEA WEO, 2004 and IEA CCC, 2005). Current projections indicate that the generation efficiency of commercial, pulverized coal fired power plants based on ultra-supercritical steam cycles would exceed 50% lower heating value (LHV) over the next decade (IEA, 2004), which will be higher than efficiencies of between 36 and 45% reported for current subcritical and supercritical steam-based plants without capture (see Section 3.7). Similarly, natural gas fired combined cycles are expected to have efficiencies of 65% by 2020 (IEA GHG, 2002b) and up from current efficiencies between 55 and 58% (see Section 3.7). In a future carbon-constrained world, these independent and ongoing developments in power cycle efficiencies will result in lower CO_2-emissions per kWh produced and hence a lower loss in overall cycle efficiency when post-combustion capture is applied.

There are proven post-combustion CO_2 capture technologies based on absorption processes that are commercially available at present. They produce CO_2 from flue gases in coal and gas-fired installations for food/beverage applications and chemicals production in capacity ranges between 6 and 800 tCO_2 d^{-1}. They require scale up to 20-50 times that of current unit capacities for deployment in large-scale power plants in the 500 MW_e capacity range (see Section 3.3.2). The inherent limitations of currently available absorption technologies when applied to post-combustion capture systems are well known and their impact on system cost can be estimated relatively accurately for a given application (see Section 3.7). Hence, with the dominant role played by air- blown energy conversion processes in the global energy infrastructure, the availability of post-combustion capture systems is important if CO_2 capture and storage becomes a viable climate change mitigation strategy.

The intense development efforts on novel solvents for improved performance and reduced energy consumption during regeneration, as well as process designs incorporating new contacting devices such as hybrid membrane-absorbent systems, solid adsorbents and high temperature regenerable sorbents, may lead to the use of more energy efficient post-combustion capture systems. However, all these novel concepts still need to prove their lower costs and reliability of operation on a commercial scale. The same considerations also apply to other advanced CO_2 capture concepts with oxy-fuel combustion or pre-combustion capture reviewed in the following sections of this chapter. It is generally not yet clear which of these emerging technologies, if any, will succeed as the dominant commercial technology for energy systems incorporating CO_2 capture.

3.4 Oxy-fuel combustion capture systems

3.4.1 Introduction

The oxy-fuel combustion process eliminates nitrogen from the flue gas by combusting a hydrocarbon or carbonaceous fuel in either pure oxygen or a mixture of pure oxygen and a CO_2-rich recycled flue gas (carbonaceous fuels include biomass). Combustion of a fuel with pure oxygen has a combustion temperature of about 3500°C which is far too high for typical power plant materials. The combustion temperature is limited to about 1300-1400°C in a typical gas turbine cycle and to about 1900°C in an oxy-fuel coal-fired boiler using current technology. The combustion temperature is controlled by the proportion of flue gas and gaseous or liquid-water recycled back to the combustion chamber.

The combustion products (or flue gas) consist mainly of carbon dioxide and water vapour together with excess oxygen required to ensure complete combustion of the fuel. It will also contain any other components in the fuel, any diluents in the oxygen stream supplied, any inerts in the fuel and from air leakage into the system from the atmosphere. The net flue gas, after cooling to condense water vapour, contains from about 80-98% CO_2 depending on the fuel used and the particular oxy-fuel combustion process. This concentrated CO_2 stream can be compressed, dried and further purified before delivery into a pipeline for storage (see Chapter 4). The CO_2 capture efficiency is very close to 100% in oxy-fuel combustion capture systems. Impurities in the CO_2 are gas components such as SO_x, NO_x, HCl and Hg derived from the fuel used, and the inert gas components, such as nitrogen, argon and oxygen, derived from the oxygen feed or air leakage into the system. The CO_2 is transported by pipeline as a dense supercritical phase. Inert gases must be reduced to a low concentration to avoid two-phase flow conditions developing in the pipeline systems. The acid gas components may need to be removed to comply with legislation covering co-disposal of toxic or hazardous waste or to avoid operations or environmental problems with disposal in deep saline reservoirs, hydrocarbon formations or in the ocean. The carbon dioxide must also be dried to prevent water condensation and corrosion in pipelines and allow use of conventional carbon-steel materials.

Although elements of oxy-fuel combustion technologies are in use in the aluminium, iron and steel and glass melting industries today, oxy-fuel technologies for CO_2 capture have yet to be deployed on a commercial scale. Therefore, the first classification between *existing technologies* and *emerging technologies* adopted in post-combustion (Section 3.3) and pre-combustion (Section 3.5) is not followed in this section. However, it is important to emphasize that the key separation step in most oxy-fuel capture systems (O_2 from air) is an 'existing technology' (see Section 3.4.5). Current methods of oxygen production by air separation comprise cryogenic distillation, adsorption using multi-bed pressure swing units and polymeric membranes. For oxy-fuel conversions requiring less than 200 $tO_2\ d^{-1}$, the adsorption system will be economic. For all the larger applications, which include power station boilers, cryogenic air separation is the economic solution (Wilkinson *et al.*, 2003a).

In the following sections we present the main oxy-fuel combustion systems classified according to how the heat of combustion is supplied and whether the flue gas is used as a working fluid (Sections 3.4.2, 3.4.3, 3.4.4). A brief overview of O_2 production methods relevant for these systems is given (Section 3.4.5). In Section 3.4.6, the emerging technology of chemical looping combustion is presented, in which pure oxygen is supplied by a metal oxide rather than an oxygen production process. The section on oxy-fuel systems closes with an overview of the status of the technology (Section 3.4.7).

3.4.2 Oxy-fuel indirect heating - steam cycle

In these systems, the oxy-fuel combustion chamber provides heat to a separate fluid by heat transfer through a surface. It can be used for either process heating, or in a boiler with a steam cycle for power generation. The indirect system can be used with any hydrocarbon or carbon-containing fuel.

The application of oxy-fuel indirect heating for CO_2 capture in process heating and power generation has been examined in both pilot-scale trials evaluating the combustion of carbonaceous fuels in oxygen and CO_2-rich recycled flue gas mixtures and engineering assessments of plant conversions as described below.

3.4.2.1 Oxy-fuel combustion trials

Work to demonstrate the application of oxy-fuel recycle combustion in process heating and for steam generation for use in steam power cycles have been mostly undertaken in pilot scale tests that have looked at the combustion, heat transfer and pollutant-forming behaviour of natural gas and coal.

One study carried out (Babcock Energy Ltd. *et al.*, 1995) included an oxy-fuel test with flue gas recycle using a 160kW, pulverized coal, low NO_x burner. The system included a heat-transfer test section to simulate fouling conditions. Test conditions included variation in recycle flow and excess O_2 levels. Measurements included all gas compositions, ash analysis and tube fouling after a 5-week test run. The work also included a case study on oxy-fuel operation of a 660 MW power boiler with CO_2 capture, compression and purification. The main test results were that NO_x levels reduced with increase in recycle rate, while SO_2 and carbon in ash levels were insensitive to the recycle rate. Fouling in the convective test section was greater with oxy-fuel firing than with air. High-slagging UK coal had worse slagging when using oxy-fuel firing, the higher excess O_2 level lowered carbon in ash and CO concentration.

For the combustion of pulverized coal, other pilot-scale tests by Croiset and Thambimuthu (2000) have reported that the flame temperature and heat capacity of gases to match fuel burning in air occurs when the feed gas used in oxy-fuel combustion has a composition of approximately 35% by volume O_2 and 65% by volume of dry recycled CO_2 (c.f. 21% by volume O_2 and the rest nitrogen in air). In practice, the presence of inerts such as ash and inorganic components in the coal, the specific fuel composition and moisture in the recycled gas stream and the coal feed will result in minor adjustments to this feed mixture composition to keep the flame temperature at a value similar to fuel combustion in air.

At conditions that match O_2/CO_2 recycle combustion to fuel burning in air, coal burning is reported to be complete (Croiset and Thambimuthu, 2000), with operation of the process at excess O_2 levels in the flue gas as low as 1-3% by volume O_2, producing a flue gas stream of 95-98% by volume dry CO_2 (the rest being excess O_2, NO_x, SO_x and argon) when a very high purity O_2 stream is used in the combustion process with zero leakage of ambient air into the system. No differences were detected in the fly ash formation behaviour in the combustor or SO_2 emissions compared to conventional air firing conditions. For NO_x on the other hand, emissions were lower due to zero thermal NO_x formation from the absence of nitrogen in the feed gas - with the partial recycling of NO_x also reducing the formation and net emissions originating from the fuel bound nitrogen. Other studies have demonstrated that the level of NO_x reduction is as high as 75% compared to coal burning in air (Chatel-Pelage *et al.*, 2003). Similar data for natural gas burning in O_2/CO_2 recycle mixtures report zero thermal NO_x emissions in the absence of air leakage into the boiler, with trace amounts produced as thermal NO_x when residual nitrogen is present in the natural gas feed (Tan *et al.*, 2002).

The above and other findings show that with the application of oxy-fuel combustion in modified utility boilers, the nitrogen-free combustion process would benefit from higher heat transfer rates (McDonald and Palkes, 1999), and if also constructed with higher temperature tolerant materials, are able to operate at higher oxygen concentration and lower flue gas recycle flows – both of which will considerably reduce overall volume flows and size of the boiler.

It should be noted that even when deploying a 2/3 flue gas recycle gas ratio to maintain a 35% by volume O_2 feed to a pulverized coal fired boiler, hot recycling of the flue gas prior to CO_2 purification and compression also reduces the size of all unit operations in the stream leaving the boiler to 1/5 that of similar equipment deployed in conventional air blown combustion systems (Chatel-Pelage *et al.*, 2003). Use of a low temperature gas purification step prior to CO_2 compression (see Section 3.4.2.2) will also eliminate the need to deploy conventional selective catalytic reduction for NO_x removal and flue gas desulphurization to purify the gas, a practice typically adopted in conventional air-blown combustion processes (see Figure 3.3). The overall reduction in flow volumes, equipment scale and simplification of gas purification steps will thus have the benefit of reducing both capital and operating costs of equipment deployed for combustion, heat transfer and final gas purification in process and power plant applications (Marin *et al.*, 2003).

As noted above for pulverized coal, oil, natural gas and biomass combustion, fluidized beds could also be fired with O_2 instead of air to supply heat for the steam cycle. The intense solid mixing in a fluidized bed combustion system can provide very good temperature control even in highly exothermic conditions, thereby minimizing the need for flue gas recycling. In principle, a variety of commercial designs for fluidized combustion boilers exist that could be retrofitted for oxygen firing. A circulating fluidized bed combustor with O_2 firing was proposed by Shimizu *et al.* (1999) to generate the heat required for the calcination of $CaCO_3$ (see also Section 3.3.3.4). More recently, plans for pilot testing of an oxy-fired circulating fluidized bed boiler have been published by Nsakala *et al.* (2003).

3.4.2.2 *Assessments of plants converted to oxy-fuel combustion*

We now discuss performance data from a recent comprehensive design study for an application of oxy-fuel combustion in a new build pulverized coal fired power boiler using a supercritical steam cycle (see Figure 3.8; Dillon *et al.*, 2005). The overall thermal efficiency on a lower heating value basis is reduced from 44.2% to 35.4%. The net power output is reduced from 677 MW_e to 532 MW_e.

Important features of the system include:

- Burner design and gas recycle flow rate have been selected to achieve the same temperatures as in air combustion (compatible temperatures with existing materials in the boiler).
- The CO_2-rich flue gas from the boiler is divided into three gas streams: one to be recycled back to the combustor, one to be used as transport and drying gas of the coal feed, and the third as product gas. The first recycle and the product stream are cooled by direct water scrubbing to remove residual particulates, water vapour and soluble acid gases such as SO_3 and HCl. Oxygen and entrained coal dust together with the second recycle stream flow to the burners.
- The air leakage into the boiler is sufficient to give a high enough inerts level to require a low temperature inert gas

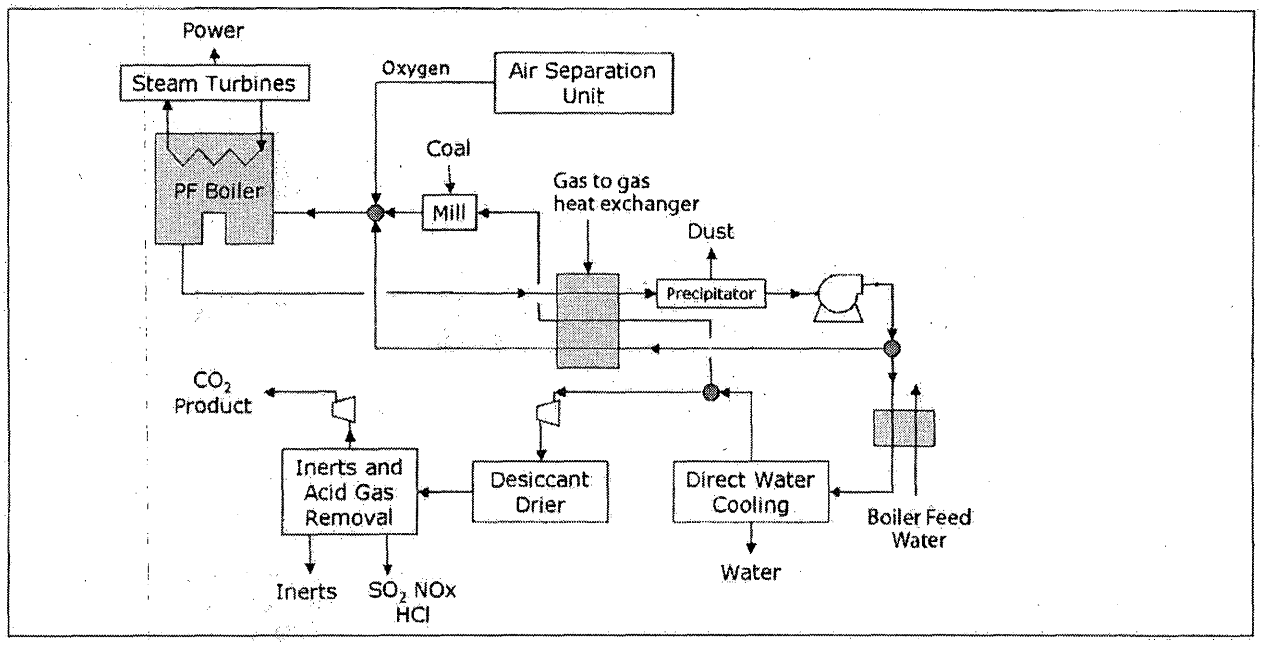


Figure 3.8 Schematic of an oxy-fuel, pulverized coal fired power plant.

removal unit to be installed, even if pure O_2 were used as the oxidant in the boiler. The cryogenic oxygen plant will, in this case, produce 95% O_2 purity to minimize power consumption and capital cost.

- The low temperature (-55°C) CO_2 purification plant (Wilkinson et al., 2003b) integrated with the CO_2 compressor will not only remove excess O_2, N_2, argon but can also remove all NO_x and SO_2 from the CO_2 stream, if high purity CO_2 is required for storage. Significantly, removal of these components before final CO_2 compression eliminates the need to otherwise incorporate upstream NO_x and SO_x removal equipment in the net flue gas stream leaving the boiler. Elimination of N_2 from the flue gas results in higher SO_x concentrations in the boiler and reduced NO_x levels. Suitable corrosion resistant materials of construction must be chosen.
- The overall heat transfer is improved in oxy-fuel firing because of the higher emissivity of the CO_2/H_2O gas mixture in the boiler compared to nitrogen and the improved heat transfer in the convection section. These improvements, together with the recycle of hot flue gas, increase the boiler efficiency and steam generation by about 5%.
- The overall thermal efficiency is improved by running the O_2 plant air compressor and the first and final stages of the CO_2 compressor without cooling, and recovering the compression heat for boiler feed water heating prior to de-aeration.

Engineering studies have also been reported by Simbeck and McDonald (2001b) and by McDonald and Palkes (1999). This work has confirmed that the concept of retrofitting oxy-fuel combustion with CO_2 capture to existing coal-fired power stations does not have any technical barriers and can make use of existing technology systems.

It has been reported (Wilkinson *et al.*, 2003b) that the application of oxy-fuel technology for the retrofit of power plant boilers and a range of refinery heaters in a refinery complex (Grangemouth refinery in Scotland) is technically feasible at a competitive cost compared to other types of CO_2 capture technologies. In this case, the existing boiler is adapted to allow combustion of refinery gas and fuel oil with highly enriched oxygen and with partial flue gas recycling for temperature control. Oxy-fuel boiler conversions only needed minor burner modifications, a new O_2 injection system and controls, and a new flue gas recycle line with a separate blower. These are cheap and relatively simple modifications and result in an increase in boiler/heater thermal efficiency due to the recycle of hot gas. Modifications to a coal-fired boiler are more complex. In this study, it was found to be more economic to design the air separation units for only 95% O_2 purity instead of 99.5% to comply with practical levels of air leakage into boilers and to separate the associated argon and nitrogen in the CO_2 inert gas removal system to produce a purity of CO_2 suitable for geological storage. After conversion of the boiler, the CO_2 concentration in the flue gas increases from 17 to 60% while the water content increases from 10 to 30%. Impurities (SO_x, NO_x) and gases (excess O_2, N_2, argon) representing about 10% of the stream are separated from CO_2 at low temperature (-55°C). After cooling, compression and drying of the separated or non-recycled flue gas, the product for storage comprises 96% CO_2 contaminated with 2% N_2, 1% argon and less than 1% O_2 and SO_2. Production of ultra-pure CO_2 for storage would also be possible if distillation steps are added to the separation process.

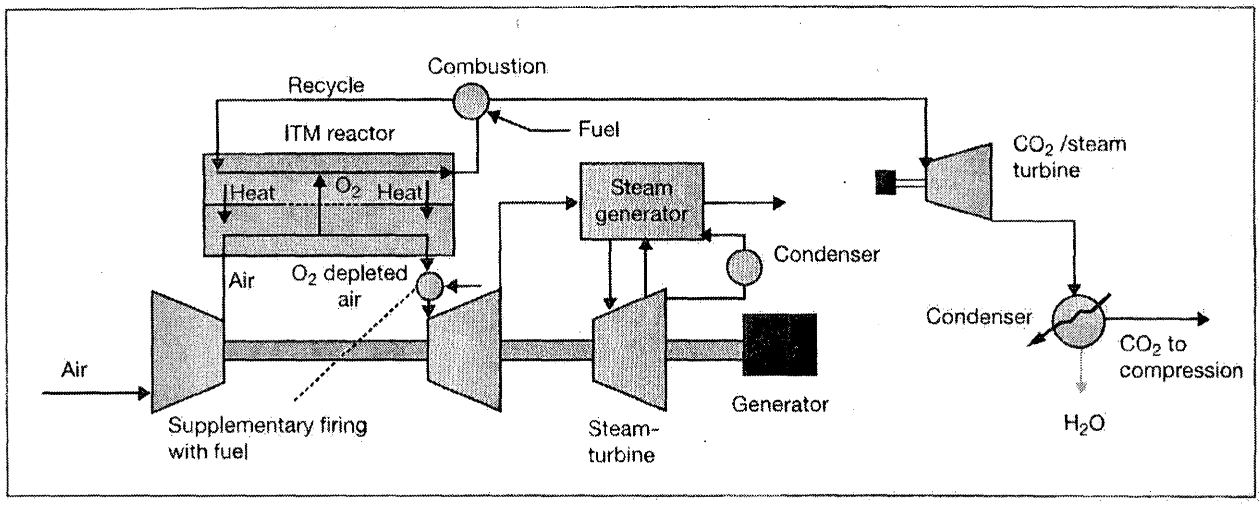


Figure 3.9 Principle flow scheme of the advanced zero emission power plant cycle.

3.4.2.3 Advanced zero emission power plant

The advanced zero emission power plant (or AZEP as outlined in Figure 3.9; Griffin *et al.*, 2003) is an indirect heating gas turbine cycle that incorporates a high-temperature oxygen transport membrane, operating at about 800°C -1000°C (see Section 3.4.5.2). This process uses a standard air-based gas turbine in a combined cycle arrangement. Three process steps take place in a reactor system that replaces the combustion chamber of a standard gas turbine: 1) separation of oxygen from hot air using the membrane and transport to the combustion section; 2) combustion and 3) heat exchange from the combustion products to the compressed air.

A net efficiency for advanced zero emission power cycle of around 49-50% LHV is claimed including CO_2 compression for transport. In order to get full advantage of the potential of the most advanced gas turbines, which have inlet temperatures of 1300°C-1400°C, an afterburner fired with natural gas in air may be added behind the reactor system. The efficiency then climbs up to 52% but now 15% of the CO_2 generated by combustion is released at the stack and is not captured.

3.4.3 Oxy-fuel direct heating - gas turbine cycle

Oxy-fuel combustion takes place in a pressurized CO_2-rich recirculating stream in a modified gas turbine. The hot gas is expanded in the turbine producing power. The turbine exhaust is cooled to provide heat for a steam cycle and water vapour is condensed by further cooling. The CO_2-rich gas is compressed in the compressor section. The net CO_2-rich combustion product is removed from the system. Only natural gas, light hydrocarbons and syngas ($CO + H_2$) can be used as fuel.

3.4.3.1 Cycle description and performance

Figure 3.10 shows how a gas turbine can be adapted to run with oxy-fuel firing using CO_2 as a working fluid. Exhaust gas leaving the heat recovery steam generator is cooled to condense water. The net CO_2 product is removed and the remaining gas is recycled to the compressor. Suitable fuels are natural gas, light to medium hydrocarbons or ($H_2 + CO$) syngas, which could be derived from coal. The use of CO_2 as the working fluid in the turbine will necessitate a complete redesign of the gas turbine (see Section 3.4.3.2). A recent study (Dillon *et al.*, 2005) gives an overall efficiency including CO_2 compression of 45%.

Two typical variants of this configuration are the so-called Matiant and Graz cycles (Mathieu, 2003; Jericha *et al.*, 2003). The Matiant cycle uses CO_2 as the working fluid, and consists of features like intercooled compressor and turbine reheat. The exhaust gas is preheating the recycled CO_2 in a heat exchanger. The CO_2 generated in combustion is extracted from the cycle behind the compressor. The net overall LHV efficiency is expected to be 45-47% and can increase above 50% in a combined cycle configuration similar to that shown in Figure 3.10. The Graz cycle consists of an integrated gas turbine and steam turbine cycle. A net LHV efficiency of above 50% has been calculated for this cycle (Jericha *et al.*, 2003).

A recent comprehensive review of gas turbine cycles with CO_2 capture provides efficiencies of different cycles on a common basis (Kvamsdal *et al.*, 2004).

3.4.3.2 The CO_2/oxy-fuel gas turbine

In existing gas turbines the molecular weight of the gases in the compressor and turbine are close to that of air (28.8). In the case of oxy-fuel combustion with CO_2-recycle the compressor fluid molecular weight is about 43 and about 40 in the turbine. The change in working fluid from air to a CO_2-rich gas results in a number of changes in properties that are of importance for the design of the compressor, combustor and the hot gas path including the turbine:

- The speed of sound is 80% of air;
- The gas density is 50% higher than air;
- The specific heat ratio is lower than air resulting in a lower temperature change on adiabatic compression or expansion. An oxy-fuel gas turbine in a combined cycle has a higher optimal pressure ratio, typically 30 to 35 compared to 15

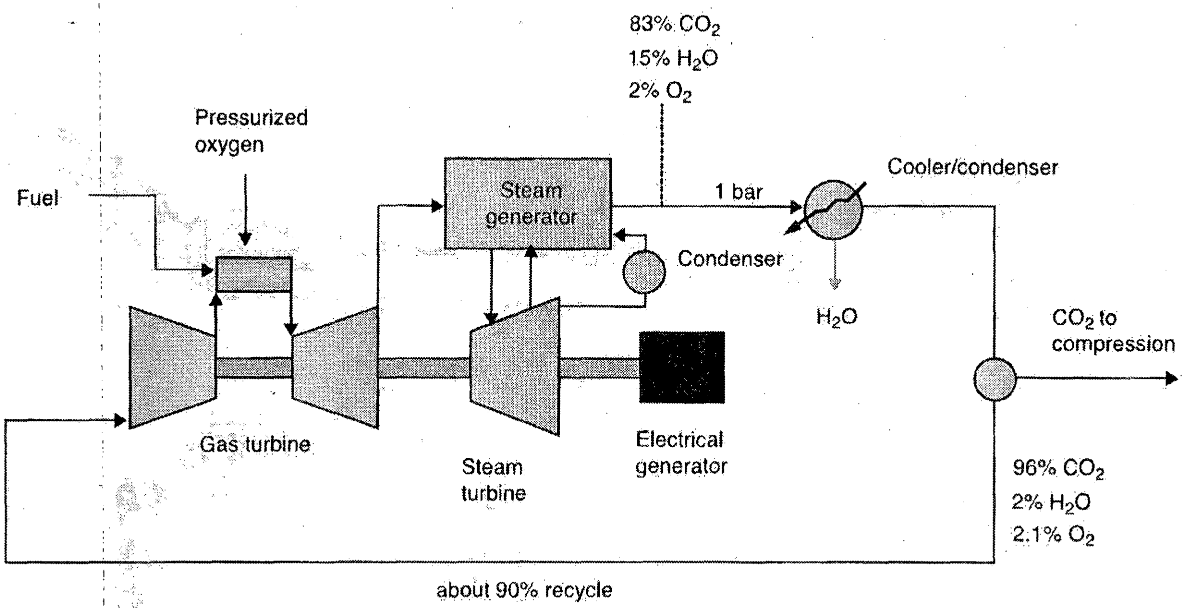


Figure 3.10 Principle of the oxy-fuel gas turbine combined cycle. Exhaust gas is recycled, compressed and used in the combustion chamber to control the temperature entering the turbine.

to 18 used with air in a combined cycle system. With the highest turbine inlet temperature consistent with material limitations, the rather high-pressure ratio results in an exhaust gas temperature of about 600°C, which is optimal for the steam cycle.

These changes in the fundamental properties of the working fluid will have a significant impact on gas turbine components, requiring completely new designs of compressors, combustors (to account for aerodynamic changes and acoustic feedbacks) and hot gas path (O_2 partial pressure must be low in oxy-fuel systems but it is also important to avoid reducing conditions for the materials of the turbine or the change to materials allowing much lower O_2 partial pressures).

3.4.4 Oxy-fuel direct heating - steam turbine cycle

In an oxy-fuel steam turbine cycle, water is pressurized as a liquid and is then evaporated, heated by the direct injection and combustion of a fuel with pure oxygen and expanded in a turbine. Most of the water in the low pressure turbine exhaust gas is cooled and condensed, prior to pumping back to a high pressure while the CO_2 produced from combustion is removed and compressed for pipeline transport. A variant of this cycle in which the heat is provided by burning natural gas fuel in-situ with pure oxygen was proposed by Yantovskii *et al.* (1992).

The direct combustion of fuel and oxygen has been practised for many years in the metallurgical and glass industries where burners operate at near stoichiometric conditions with flame temperatures of up to 3500°C. A water quenched H_2/O_2 burner capable of producing 60 tonne h^{-1}, 6 MPa super heated steam was demonstrated in the mid-1980s (Ramsaier *et al.*, 1985). A recent development by Clean Energy Systems incorporating these concepts where a mixture of 90 % by volume superheated steam and 10% CO_2 is produced at high temperature and pressure to power conventional or advanced steam turbines is shown in Figure 3.11. The steam is condensed in a low-pressure condenser and recycled, while CO_2 is extracted from the condenser, purified and compressed. (Anderson *et al.*, 2003 and Marin *et al.*, 2003).

Plants of this type require a clean gaseous or liquid fuel and will operate at 20 to 50 MPa pressure. The steam plus CO_2 generator is very compact. Control systems must be very precise as start-up and increase to full flow in a preheated plant can take place in less than 2 seconds. Precise control of this very rapid start was demonstrated (Ramsaier *et al.*, 1985) in a 60 tonne steam h^{-1} unit. The Clean Energy Systems studies claim efficiencies as high as 55% with CO_2 capture depending on the process conditions used.

The Clean Energy Systems technology can be initially applied with current steam turbines (565°C inlet temperature). The main technical issue is clearly the design of the steam turbines which could be used at inlet temperatures up to 1300°C by applying technology similar to that used in the hot path of gas turbines. The combustor itself (the 'gas generator') is adapted from existing rocket engine technology. In 2000, Clean Energy Systems proved the concept with a 110 kW pilot project conducted at the University of California Davis. A 20 MW thermal gas generator was successfully operated in a test run of the order of a few minutes in early 2003. A zero emissions demonstration plant (up to 6 MW electrical) is now on-line. US Department of Energy's National Energy Technology Laboratory designed the reheater (Richards, 2003) and NASA tested it in 2002. Much more technology development and demonstration

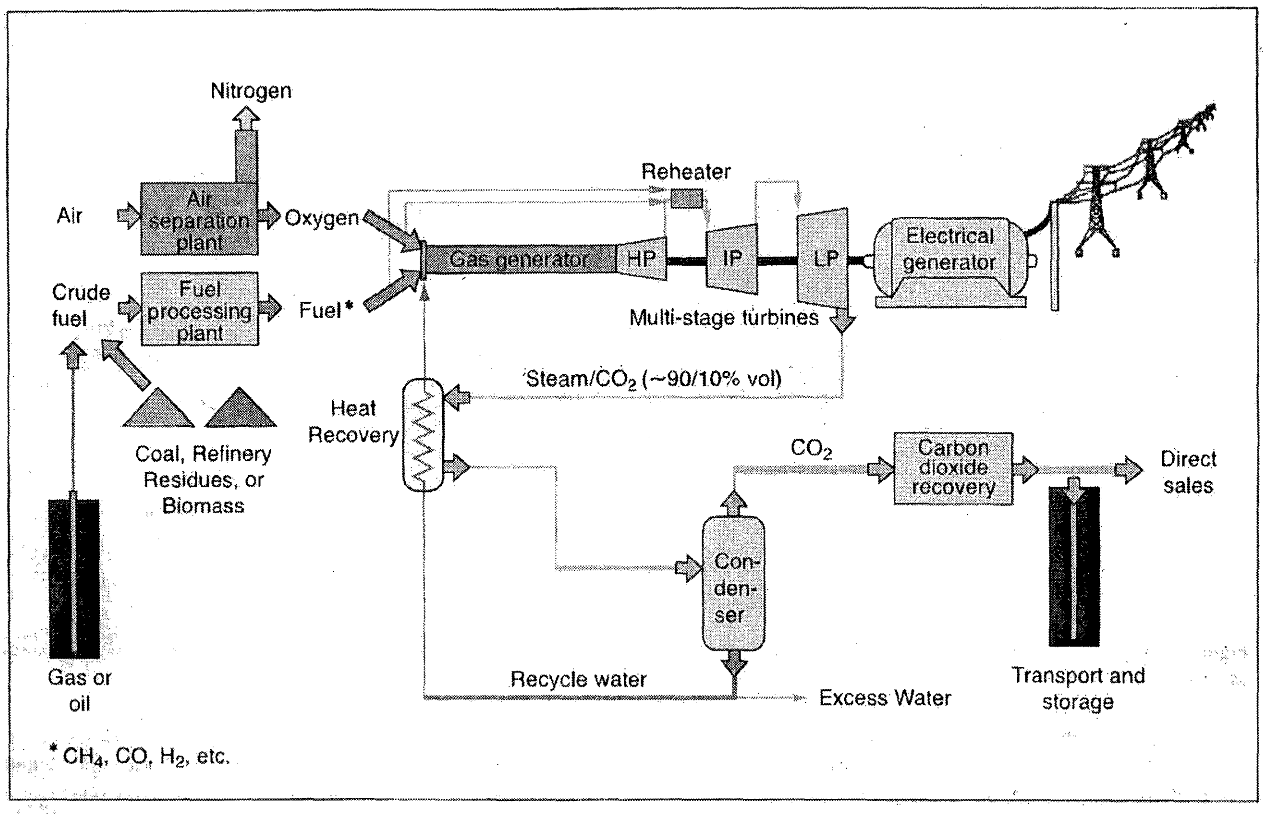


Figure 3.11 Principle of the Clean Energy Systems cycle. The combustion of the fuel and oxygen is cooled by injection of liquid-water, which is recycled in the process.

is needed on this proposed power cycle, but it shows significant potential for low capital cost and high efficiency.

3.4.5 *Techniques and improvements in oxygen production*

Oxygen is the key requirement for any oxy-fuel combustion system. It is also a key technology for pre-combustion CO_2 capture (see Section 3.5). In the next paragraphs, existing large-scale O_2 production methods are described first, followed by emerging concepts aimed at reducing the energy consumption and cost.

3.4.5.1 Cryogenic oxygen production

The very large quantities of oxygen required for CO_2 capture using the techniques of oxy-fuel combustion and pre-combustion de-carbonization can only be economically produced, at present, by using the established process of oxygen separation from air by distillation at cryogenic temperatures (Latimer, 1967). This is a technology that has been practiced for over 100 years.

In a typical cryogenic air separation plant (Castle, 1991; Figure 3.12), air is compressed to a pressure of 0.5 to 0.6 MPa and purified to remove water, CO_2, N_2O and trace hydrocarbons which could accumulate to dangerous levels in oxygen-rich parts of the plant, such as the reboiler condenser. Two or more switching fixed bed adsorbers are used, which can be regenerated by either temperature or pressure swing, using in each case, a low pressure waste nitrogen stream. The air is cooled against returning products (oxygen and nitrogen) in a battery of aluminium plate-fin heat exchangers and separated into pure oxygen and nitrogen fractions in a double distillation column, which uses aluminium packing.

Oxygen can be pumped as liquid and delivered as a high-pressure gas at up to 10 MPa. Pumped oxygen plants have largely replaced the oxygen gas compression systems. They have virtually identical power consumptions but in a pumped cycle, a high-pressure air booster compressor provides a means of efficiently vaporizing and heating the liquid oxygen stream to ambient temperature. Current plant sizes range up to 3500 $tO_2\,d^{-1}$ and larger single train plants are being designed. Typical power consumption for the delivery of 95% O_2 at low pressure (0.17 MPa, a typical pressure for an oxy-fuel application) is 200 to 240 kWh/tO_2. There are numerous process cycle variations particularly for the production of oxygen at less than 97.5% purity which have been developed to reduce power and capital cost. Note that adsorption and polymeric membrane methods of air separation are only economic for small oxygen production rates.

3.4.5.2 High temperature oxygen ion transport membranes

Ceramic mixed metal oxides have been developed which exhibit simultaneous oxygen ion and electron conduction at

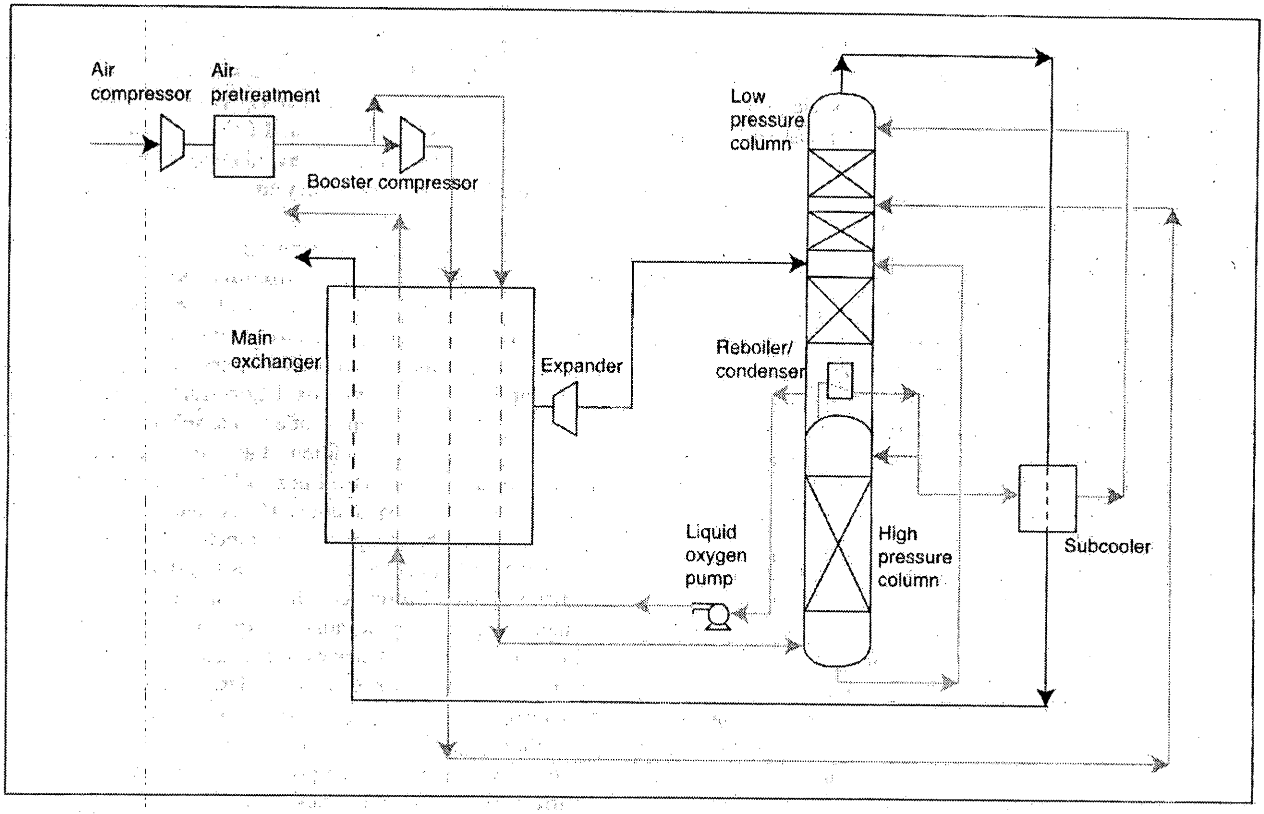


Figure 3.12a Oxygen production by distillation of liquid air.

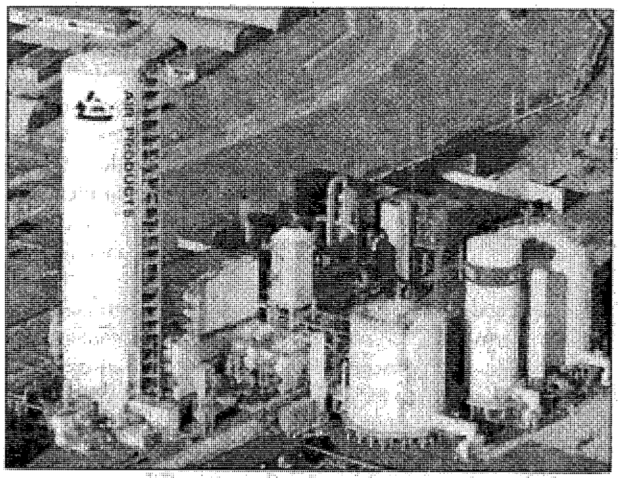


Figure 3.12b A 3000 t day^{-1} oxygen plant (Courtesy of Air Products).

temperatures above 500°C and preferably above 700°C (Skinner and Kilner 2003; Bouwmeester and Van Laar, 2002; Dyer *et al.*, 2000; Bredesen *et al.*, 2004). Typical crystal structures which exhibit these properties include the perovskites and the brownmillerites. The selectivity of these materials for oxygen is infinite. The oxygen permeability is primarily controlled by the oxygen ion vacancies in the metal oxide lattice. A difference in oxygen partial pressure across the membrane will cause oxygen molecules to ionize on the ceramic surface and pass into the crystal structure while simultaneously on the permeate side of the membrane, the oxygen ions give up their electrons and leave the ceramic in the region of lower activity. The electron conduction path is through the metal ions in the lattice. Unlike conventional membranes, the flux through the ceramic is a function of the partial pressure ratio. In the technical literature, the engineered structures of these ceramic mixed metal oxides are referred to as *ion transport membranes, ITM* or *oxygen transport membranes, OTM*.

The oxygen transport membrane can be fabricated in the form of plain tubes or as hollow fins on a central collector tube (Armstrong *et al.*, 2002). The finned elements are then mounted in tube sheets within a pressure vessel with high-pressure air flowing over the fins. There are several new concepts that have been proposed for using oxygen transport membranes in power cycles with CO_2 capture. A prime example of an oxy-fuel gas turbine cycle that incorporates an oxygen transport membrane for oxygen production is the advanced zero emission power plant described in Section 3.4.2.3. Another example is found in Sundnes (1998).

Development status

Oxygen transport membrane systems for oxygen production are currently in the early stages of development by at least two consortia receiving research funding from the US Department of Energy and the European Commission. The concept has now reached the pilot plant stage and projected cost, manufacturing procedures and performance targets for full size systems have been evaluated. Systems capable of large-scale production are projected to be available after industrial demonstration in about 7 years time (Armstrong *et al.*, 2002).

3.4.6 *Chemical looping combustion*

Originally proposed by Richter and Knoche (1983) and with subsequent significant contributions by Ishida and Jin (1994), the main idea of chemical looping combustion is to split combustion of a hydrocarbon or carbonaceous fuel into separate oxidation and reduction reactions by introducing a suitable metal oxide as an oxygen carrier to circulate between two reactors (Figure 3.13). Separation of oxygen from air is accomplished by fixing the oxygen as a metal oxide. No air separation plant is required. The reaction between fuel and oxygen is accomplished in a second reactor by the release of oxygen from the metal oxide in a reducing atmosphere caused by the presence of a hydrocarbon or carbonaceous fuel. The recycle rate of the solid material between the two reactors and the average solids residence time in each reactor, control the heat balance and the temperature levels in each reactor. The effect of having combustion in two reactors compared to conventional combustion in a single stage is that the CO_2 is not diluted with nitrogen gas, but is almost pure after separation from water, without requiring any extra energy demand and costly external equipment for CO_2 separation.

Possible metal oxides are some oxides of common transition-state metals, such as iron, nickel, copper and manganese (Zafar *et al.*, 2005). The metal/metal oxide may be present in various forms, but most studies so far have assumed the use of particles with diameter 100-500 µm. In order to move particles between the two reactors, the particles are fluidized. This method also ensures efficient heat and mass transfer between the gases and the particles. A critical issue is the long-term mechanical and chemical stability of the particles that have to undergo repeated cycles of oxidation and reduction, to minimize the make-up requirement. When a chemical looping cycle is used in a gas turbine cycle, the mechanical strength for crushing and the filtration system is important to avoid damaging carry-over to the turbine.

The temperature in the reactors, according to available information in the literature, may be in the range 800°C-1200°C. NO_x formation at these typical operating temperatures will always be low. The fuel conversion in the reduction reactor may not be complete, but it is likely (Cho *et al.*, 2002) that the concentrations of methane and CO when burning natural gas are very small. In order to avoid deposit of carbon in the reduction reactor, it is necessary to use some steam together with the fuel.

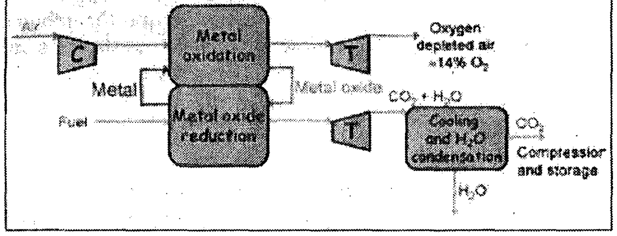


Figure 3.13 The chemical looping combustion principle in a gas turbine cycle.

The chemical looping principle may be applied either in a gas turbine cycle with pressurized oxidation and reduction reactors, or in a steam turbine cycle with atmospheric pressure in the reactors. In the case of a gas turbine cycle, the oxidation reactor replaces the combustion chamber of a conventional gas turbine. The exothermic oxidation reaction provides heat for increasing the air temperature entering the downstream expansion turbine. In addition, the reduction reactor exit stream may also be expanded in a turbine together with steam production for power generation. The cooled low pressure CO_2 stream will then be compressed to pipeline pressure. Another option is to generate steam using heat transfer surfaces in the oxidation reactor. Current circulating fluidized bed combustion technology operating at atmospheric pressure in both the oxidation and reduction stages necessitates the use of a steam turbine cycle for power generation. Using natural gas as fuel in a chemical looping combustion cycle which supplies a gas turbine combined cycle power plant and delivering CO_2 at atmospheric pressure, the potential for natural gas fuel-to-electricity conversion efficiency is estimated to be in the range 45-50% (Brandvoll and Bolland, 2004). Work on chemical looping combustion is currently in the pilot plant and materials research stage.

3.4.7 *Status and outlook*

Oxy-fuel combustion applied to furnaces, process heaters, boilers and power generation systems is feasible since no technical barriers for its implementation have been identified. Early use of this capture technology is likely to address applications involving indirect heating in power generation and process heating (Section 3.4.2), since these options involve the minimal modification of technologies and infrastructure that have hitherto been already developed for the combustion of hydrocarbon or carbonaceous fuels in air. However, several novel applications proposed for direct heating in steam turbine cycles or gas turbine cycles for power generation (Sections 3.4.3 and 3.4.4) still require the development of new components such as oxy-fuel combustors, higher temperature tolerant components such as CO_2- and H_2O-based turbines with blade cooling, CO_2 compressors and high temperature ion transport membranes for oxygen separation. As for Chemical Looping Combustion, it is currently still at an early stage of development.

The potential for thermal efficiencies for oxy-fuel cycles with CO_2 capture, assuming the current state of development in power plant technology, is depicted in Figures 3.6 and 3.7. Power generation from pulverized coal fired systems, using supercritical steam conditions presently operate at efficiencies around 45% (LHV), while projections to the 2010-2020 time frame are predicting efficiencies above 50% (IEA, 2004) for plants using ultra-supercritical steam conditions. An increase in efficiency of more than 5% can therefore be expected for future oxy-fuel capture systems based on coal firing that could potentially match the best efficiencies realisable today for pulverized coal-fired plants without CO_2 capture. Similarly, natural gas fired combined cycles will have efficiencies of 65% in 2020 (IEA GHG, 2000b and up from current efficiencies between 55 and 58%), which will enable plant efficiencies for natural gas fired oxy-fuel cycles with CO_2 capture above 50%. The energy penalty for producing oxygen is by far the most important cause for reduced efficiency in an oxy-fuel cycle compared to a conventional power plant.

Current technology development envisages very high efficiency separation of NO_x, SO_x, and Hg, as part of the CO_2 compression and purification system. Improved separation efficiencies of these contaminants are possible based on further process and heat integration in the power cycle.

Current cryogenic oxygen technology is showing continuing cost reduction based on improved compressor efficiencies, more efficient process equipment and larger scale plants. The new high temperature oxygen membrane could significantly improve power generation efficiency and reduce capital cost.

Future oxy-fuel demonstration plants could be based on retrofits to existing equipment such as process heaters and boilers, in order to minimize development costs and achieve early market entry. In this respect, power systems of reference for oxy-fuel combustion capture are mainly the steam-based pulverized coal and natural gas fired plants that currently represent up to 1468 GW_e, or 40% (IEA WEO, 2004) of the existing global infrastructure (see also Section 3.1.2.3). Several demonstration units may be expected within the next few years particularly in Europe, USA, Canada and Australia where active research initiatives are currently underway. As these developments proceed and the technologies achieve market penetration they may become competitive relative to alternate options based on pre- and post-combustion CO_2 capture. A significant incentive to the development of oxy-fuel combustion technology, as well as for pre- and post-combustion capture technologies, is the introduction of environmental requirements and/or fiscal incentives to promote CO_2 capture and storage.

3.5 Pre-combustion capture systems

3.5.1 *Introduction*

A pre-combustion capture process typically comprises a first stage of reaction producing a mixture of hydrogen and carbon monoxide (syngas) from a primary fuel. The two main routes are to add steam (reaction 1), in which case the process is called 'steam reforming', or oxygen (reaction 2) to the primary fuel. In the latter case, the process is often called 'partial oxidation' when applied to gaseous and liquid fuels and 'gasification' when applied to a solid fuel, but the principles are the same.

Steam reforming

$$C_xH_y + xH_2O \leftrightarrow xCO + (x+y/2)H_2 \quad \Delta H \text{ +ve} \qquad (1)$$

Partial oxidation

$$C_xH_y + x/2O_2 \leftrightarrow xCO + (y/2)H_2 \quad \Delta H \text{ –ve} \qquad (2)$$

This is followed by the 'shift' reaction to convert CO to CO_2 by the addition of steam (reaction 3):

Water Gas Shift Reaction

$$CO + H_2O \leftrightarrow CO_2 + H_2 \quad \Delta H \text{ -41 kJ mol}^{-1} \quad (3)$$

Finally, the CO_2 is removed from the CO_2/H_2 mixture. The concentration of CO_2 in the input to the CO_2/H_2 separation stage can be in the range 15-60% (dry basis) and the total pressure is typically 2-7 MPa. The separated CO_2 is then available for storage.

It is possible to envisage two applications of pre-combustion capture. The first is in producing a fuel (hydrogen) that is essentially carbon-free. Although the product H_2 does not need to be absolutely pure and may contain low levels of methane, CO or CO_2, the lower the level of carbon-containing compounds, the greater the reduction in CO_2 emissions. The H_2 fuel may also contain inert diluents, such as nitrogen (when air is typically used for partial oxidation), depending on the production process and can be fired in a range of heaters, boilers, gas turbines or fuel cells.

Secondly, pre-combustion capture can be used to reduce the carbon content of fuels, with the excess carbon (usually removed as CO_2) being made available for storage. For example, when using a low H:C ratio fuel such as coal it is possible to gasify the coal and to convert the syngas to liquid Fischer-Tropsch fuels and chemicals which have a higher H:C ratio than coal. In this section, we consider both of these applications.

This section reports on technologies for the production of H_2 with CO_2 capture that already exist and those that are currently emerging. It also describes enabling technologies that need to be developed to enhance the pre-combustion capture systems for power, hydrogen or synfuels and chemicals production or combination of all three.

3.5.2 *Existing technologies*

3.5.2.1 *Steam reforming of gas and light hydrocarbons*

Steam reforming is the dominant technology for hydrogen production today and the largest single train plants produce up to 480 $tH_2\ d^{-1}$. The primary energy source is often natural gas. Then the process is referred to as steam methane reforming (SMR), but can also be other light hydrocarbons, such as naphtha. The process begins with the removal of sulphur compounds from the feed, since these are poisons to the current nickel-based catalyst and then steam is added. The reforming reaction (1), which is endothermic, takes place over a catalyst at high temperature (800°C-900°C). Heat is supplied to the reactor tubes by burning part of the fuel (secondary fuel). The reformed gas is cooled in a waste heat boiler which generates the steam needed for the reactions and passed into the CO shift system. Shift reactors in one or two stages are used to convert most of the CO in the syngas to CO_2 (Reaction 3, which is exothermic).

The conventional two-stage CO conversion reduces the CO concentration in syngas (or in hydrogen) down to 0.2-0.3%. High temperature shift reactors operating between 400°C and 550°C and using an iron-chromium catalyst leave between 2% and 3% CO in the exit gas (dry basis). Copper-based catalyst can be used at temperatures from 180°C-350°C and leave from 0.2-1% CO in the exhaust. Lower CO content favours higher CO_2 recovery. The gas is then cooled and hydrogen is produced by a CO_2/H_2 separation step. Until about 30 years ago, the CO_2 was removed using a chemical (solvent) absorption process such as an amine or hot potassium carbonate and was rejected to atmosphere as a pure stream from the top of the regenerator. There are many of these plants still in use and the CO_2 could be captured readily.

Modern plants, however, use a pressure swing adsorber (PSA), where gases other than H_2 are adsorbed in a set of switching beds containing layers of solid adsorbent such as activated carbon, alumina and zeolites (see the fuller description of PSA in Section 3.5.2.9). The H_2 exiting the PSA (typically about 2.2 MPa) can have a purity of up to 99.999%, depending on the market need. The CO_2 is contained in a stream, from the regeneration cycle, which contains some methane and H_2. The stream is used as fuel in the reformer where it is combusted in air and the CO_2 ends up being vented to atmosphere in the reformer flue gas. Hence, to capture CO_2 from modern SMR plants would require one of the post-combustion processes described above in Section 3.3. Alternatively, the PSA system could be designed not only for high recovery of pure H_2 but also to recover pure CO_2 and have a fuel gas as the third product stream.

In a design study for a large modern plant (total capacity 720 $tH_2\,d^{-1}$), the overall efficiency of making 6.0 MPa H_2 from natural gas with CO_2 vented that is without CO_2 capture, is estimated to be 76%, LHV basis, with emissions of 9.1 kg CO_2/kg H_2 (IEA GHG, 1996). The process can be modified (at a cost) to provide a nearly pure CO_2 co-product. One possibility is to remove most of the CO_2 from the shifted, cooled syngas in a 'wet' CO_2 removal plant with an appropriate amine solvent. In this case the CO_2-deficient syngas exiting the amine scrubber is passed to a PSA unit from which relatively pure H_2 is recovered and the PSA purge gases are burned along with additional natural gas to provide the needed reformer heat. The CO_2 is recovered from the amine solvent by heating and pressurized for transport. Taking into account the power to compress the CO_2 (to 11.2 MPa) reduces the efficiency to about 73% and the emission rate to 1.4 $kgCO_2/kgH_2$, while the CO_2 removal rate is 8.0 $kgCO_2/kgH_2$

3.5.2.2 *Partial oxidation of gas and light hydrocarbons*

In the partial oxidation (POX) process (reaction 2), a fuel reacts with pure oxygen at high pressure. The process is exothermic and occurs at high temperatures (typically 1250°C-1400°C). All the heat required for the syngas reaction is supplied by the partial combustion of the fuel and no external heat is required. As with SMR, the syngas will be cooled, shifted and the CO_2 removed from the mixture. The comments made on the separation of CO_2 from SMR syngas above apply equally to the POX process. POX is a technology in common use today, the efficiency is lower than SMR, but the range of fuels that can be processed is much wider.

For large-scale hydrogen production, the oxygen is supplied from a cryogenic air separation unit (ASU). The high investment and energy consumption of the ASU is compensated by the higher efficiency and lower cost of the gasification process and the absence of N_2 (from the air) in the syngas, which reduces the separation costs considerably. However for pre-combustion de-carbonization applications, in which the hydrogen would be used as fuel in a gas turbine, it will be necessary to dilute the H_2 with either N_2 or steam to reduce flame temperature in the gas turbine combustor and to limit NO_x emission levels. In this case the most efficient system will use air as the oxidant and produce a H_2/N_2 fuel mixture (Hufton *et al.* 2005)

3.5.2.3 *Auto-thermal reforming of gas and light hydrocarbons*

The autothermal reforming (ATR) process can be considered as a combination of the two processes described above. The heat required in the SMR reactor is generated by the partial oxidation reaction (2) using air or oxygen, but because steam is supplied to the reactor as well as excess natural gas, the endothermic reforming reaction (1) occurs in a catalytic section of the reactor downstream of the POX burner. The addition of steam enables a high conversion of fuel to hydrogen at a lower temperature. Operating temperatures of the autothermal process are typically 950-1050°C, although this depends on the design of the process. An advantage of the process, compared to SMR, is the lower investment cost for the reactor and the absence of any emissions of CO_2 since all heat release is internal, although this is largely offset by investment and operating cost for the oxygen plant. The range of fuels that can be processed is similar to the SMR process, but the feed gas must be sulphur free. CO_2 capture is accomplished as described above for the steam methane reforming.

3.5.2.4 *Gas heated reformer*

Each of the three syngas generation technologies, SMR, ATR and POX produce high temperature gas which must be cooled, producing in each case a steam flow in excess of that required by the reforming and shift reactions. It is possible to reduce this excess production by, for example, using preheated air and a pre-reformer in an SMR plant. Another technique is to use the hot syngas, leaving the primary reactor, as the shell-side heating fluid in a tubular steam/hydrocarbon reforming reactor which can operate in series, or in parallel, with the primary reactor (Abbott *et al.*, 2002). The addition of a secondary gas heated reformer will increase the hydrogen production by up to 33% and eliminate the excess steam production. The overall efficiency is improved and specific capital cost is typically reduced by 15%. Again, CO_2 capture is accomplished as described previously for steam methane reforming.

3.5.2.5 *Gasification of coal, petroleum residues, or biomass*

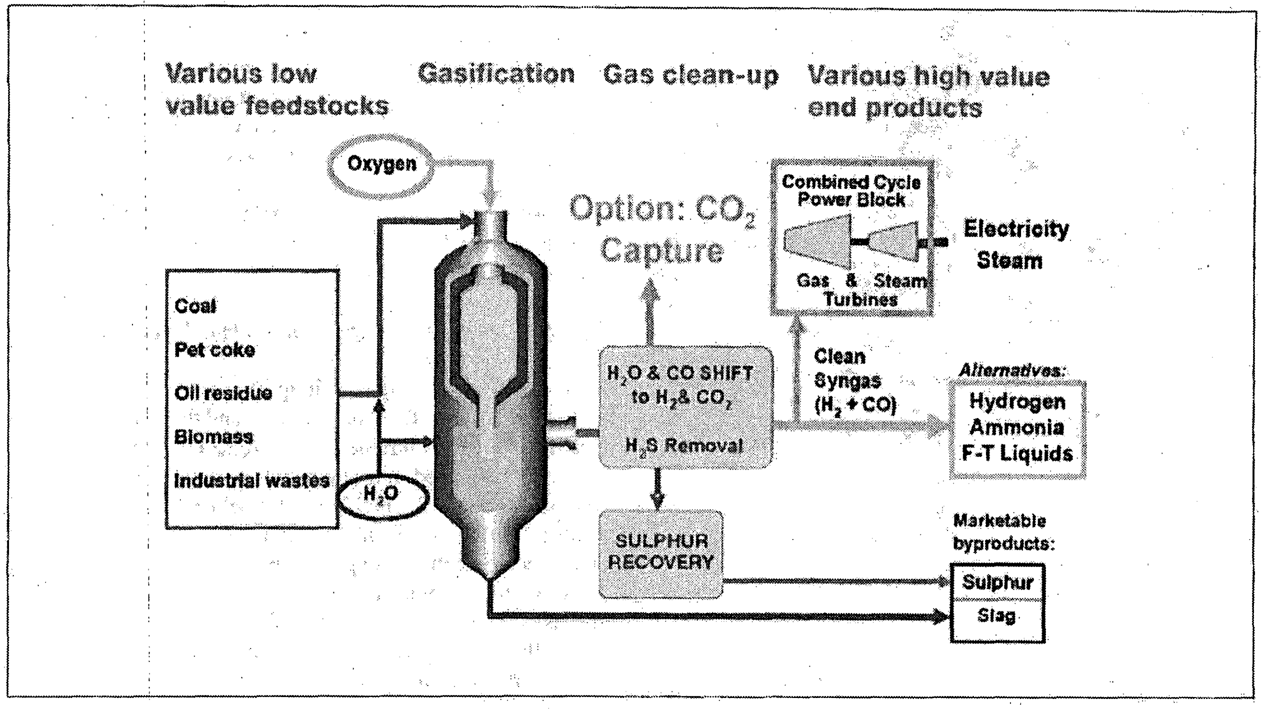


Figure 3.14 Simplified schematic of a gasification process showing options with CO_2 capture and electricity, hydrogen or chemical production.

Gasification (see Figure 3.14) is a chemical process aimed at making high-value products (chemicals, electricity, clean synthetic fuels) out of low-value solid feedstocks such as coal, oil refining residues, or biomass. Gasification is basically partial oxidation (reaction 2), although steam is also supplied to the reactor in most processes. Fixed bed, fluidized bed or entrained flow gasifiers can be used. These can have very different characteristics with respect to oxidant (air or O_2), operating temperature (up to 1350°C), operating pressure (0.1-7 MPa), feed system (dry or water slurry), syngas cooling method (water quench or via radiative and convective heat exchangers) and gas clean-up system deployed. These alternative design options determine the fraction of feedstock converted to syngas, syngas composition and cost. As economics depend strongly on scale, gasification is generally considered to be suitable only for large plants. The gasifier output contains CO, H_2, CO_2, H_2O and impurities (e.g., N_2, COS, H_2S, HCN, NH_3, volatile trace minerals and Hg) that must be managed appropriately.

A worldwide survey of commercial gasification projects identified 128 operating gasification plants with 366 gasifiers producing 42,700 MW_t of syngas (NETL-DOE, 2002 and Simbeck, 2001a). There are also about 24,500 MW_t of syngas projects under development or construction, with 4000-5000 MW_t of syngas added annually. The feedstocks are mainly higher rank coals and oil residues. Most commercial gasification growth for the last 20 years has involved entrained-flow gasifiers, for which there are three competing systems on the market. Recent commercial gasification development has been mainly with industrial ammonia production, industrial polygeneration (in which clean syngas is used to make electricity and steam along with premium syngas chemicals) and IGCC power plants. Commercial experience with biomass gasification and fluidized bed gasification has been limited.

CO_2 capture technology is well established for gasification systems that make chemicals and synthetic fuels (NETL-DOE, 2002). Gasification-based NH_3 plants (many in China) include making pure H_2 and CO_2 separation at rates up to 3500 $tCO_2\ d^{-1}$ per plant. South African plants making Fischer-Tropsch fuels and chemicals and a North Dakota plant making synthetic natural gas (SNG) from coal also produce large streams of nearly pure CO_2. Figure 3.15 shows a picture of the North Dakota gasification plant in which 3.3 $MtCO_2\ yr^{-1}$ is captured using a refrigerated methanol-based, physical solvent scrubbing process (Rectisol process, see Section 3.5.2.11 and Table 3.2). Most of this captured CO_2 is vented and about 1.5 Mtonnes yr^{-1} of this stream is currently pipelined to the Weyburn, Canada enhanced oil recovery and CO_2 storage project (see Chapter 5).

When CO_2 capture is an objective, O_2-blown and high-pressure systems are preferred because of the higher CO_2 partial pressures. De-carbonization via gasification entails lower energy penalties for CO_2 capture than does post-combustion capture when considering only the separation stage, because the CO_2 can be recovered at partial pressures up to 3 orders of magnitude higher. This greatly reduces CO_2 absorber size, solvent circulation rates and CO_2 stripping energy requirements. However, additional energy penalties are incurred in shifting the CO in the syngas to CO_2 and in other parts of the system (see examples for IGCC plant with CO_2 capture in Figures 3.6 and 3.7). Recent analyses for bituminous coals (see, for example, IEA GHG, 2003) suggest using simple high-pressure

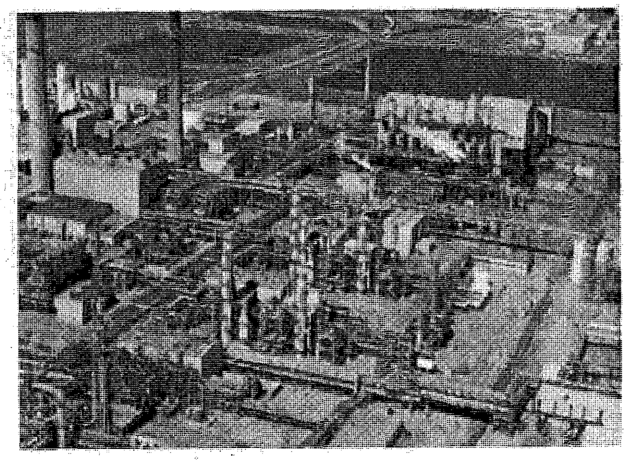


Figure 3.15 North Dakota coal gasification plant with 3.3 $MtCO_2$ yr^{-1} capture using a cold methanol, physical solvent process (cluster of 4 tall columns in the middle of the picture represent the H_2S and CO_2 capture processes; part of the captured stream is used for EOR with CO_2 storage in Weyburn, Saskatchewan, Canada).

entrained-flow gasifiers with water slurry feed and direct water quench followed by 'sour' (sulphur-tolerant) shift reactors and finally co-removal of CO_2 and H_2S by physical absorption. With sour shifting, hot raw syngas leaving the gasifier requires only one cooling cycle and less processing. Oxygen requirements increase for slurry fed gasifiers and conversion efficiencies decline with higher cycle efficiency losses with quench cooling. Similar trends are also noted with a shift from bituminous to lower rank sub-bituminous coal and lignite (Breton and Amick, 2002). Some analyses (e.g., Stobbs and Clark, 2005) suggest that the advantages of pre-combustion over post-combustion de-carbonization may be small or disappear for low-rank coals converted with entrained-flow gasifiers. High-pressure, fluidized-bed gasifiers may be better suited for use with low-rank coals, biomass and various carbonaceous wastes. Although there are examples of successful demonstration of such gasifiers (e.g., the high temperature Winkler, Renzenbrink *et al.*, 1998), there has been little commercial-scale operating experience.

The H_2S in syngas must be removed to levels of tens of ppm for IGCC plants for compliance with SO_2 emissions regulations and to levels much less than 1 ppm for plants that make chemicals or synthetic fuels, so as to protect synthesis catalysts. If the CO_2 must be provided for storage in relatively pure form, the common practice would be to recover first H_2S (which is absorbed more readily than CO_2) from syngas (along with a small amount of CO_2) in one recovery unit, followed by reduction of H_2S to elemental sulphur in a Claus plant and tail gas clean-up, and subsequent recovery of most of the remaining CO_2 in a separate downstream unit. An alternative option is to recover sulphur in the form of sulphuric acid (McDaniel and Hormick, 2002). If H_2S/CO_2 co-storage is allowed, however, it would often be desirable to recover H_2S and CO_2 in the same physical absorption unit, which would lead to moderate system cost savings (IEA GHG, 2003; Larson and Ren, 2003; Kreutz *et al.*, 2005) especially in light of the typically poor prospects for selling byproduct sulphur or sulphuric acid. Although co-storage of H_2S and CO_2 is routinely pursued in Western Canada as an acid gas management strategy for sour natural gas projects (Bachu and Gunter, 2005), it is not yet clear that co-storage would be routinely viable at large scales - a typical gasification-based energy project would involve an annual CO_2 storage rate of 1-4 Mtonnes yr^{-1}, whereas the total CO_2 storage rate for all 48 Canadian projects is presently only 0.48 Mtonnes yr^{-1} (Bachu and Gunter, 2005).

3.5.2.6 Integrated gasification combined cycle (IGCC) for power generation

In a coal IGCC, syngas exiting the gasifier is cleaned of particles, H_2S and other contaminants and then burned to make electricity via a gas turbine/steam turbine combined cycle. The syngas is generated and converted to electricity at the same site, both to avoid the high cost of pipeline transport of syngas (with a heating value only about 1/3 of that for natural gas) and to cost-effectively exploit opportunities for making extra power in the combined cycle's steam turbine using steam from syngas cooling. The main drivers for IGCC development were originally the prospects of exploiting continuing advances in gas turbine technology, the ease of realizing low levels of air-pollutant emissions when contaminants are removed from syngas, and greatly reduced process stream volumes compared to flue gas streams from combustion which are at low pressure and diluted with nitrogen from air.

Since the technology was initially demonstrated in the 1980s, about 4 GW_e of IGCC power plants have been built. Most of this capacity is fuelled with oil or petcoke; less than 1 GW_e of the total is designed for coal (IEA CCC, 2005) and 3 out of 4 plants currently operating on coal and/or petcoke. This experience has demonstrated IGCC load-following capability, although the technology will probably be used mainly in base load applications. All coal-based IGCC projects have been subsidized, whereas only the Italian oil-based IGCC projects have been subsidized. Other polygeneration projects in Canada, the Netherlands and the United States, as well as an oil-based IGCC in Japan, have not been subsidized (Simbeck, 2001a).

IGCC has not yet been deployed more widely because of strong competition from the natural gas combined cycle (NGCC) wherever natural gas is readily available at low prices, because coal-based IGCC plants are not less costly than pulverized coal fired steam-electric plants and because of availability (reliability) concerns. IGCC availability has improved in recent years in commercial-scale demonstration units (Wabash River Energy, 2000; McDaniel and Hornick, 2002). Also, availability has been better for industrial polygeneration and IGCC projects at oil refineries and chemical plants where personnel are experienced with the chemical processes involved. The recent rise in natural gas prices in the USA has also increased interest in IGCC.

Because of the advantages for gasification of CO_2 capture at high partial pressures discussed above, IGCC may be attractive for coal power plants in a carbon-constrained world (Karg and Hannemann, 2004). CO_2 capture for pre-combustion systems is commercially ready, however, no IGCC plant incorporating CO_2 capture has yet been built. With current technology, average estimates of the energy penalties and the impact of increased fuel use for CO_2 removal are compared with other capture systems in Figures 3.6 and 3.7 and show the prospective potential of IGCC options. The data in Figures 3.6 and 3.7 also show that some IGCC options may be different from others (i.e., slurry fed and quench cooled versus dry feed and syngas cooling) and their relative merits in terms of the capital cost of plant and the delivered cost of power are discussed in Section 3.7.

3.5.2.7 *Hydrogen from coal with CO_2 capture*

Relative to intensively studied coal IGCC technology with CO_2 capture, there are few studies in the public domain on making H_2 from coal via gasification with CO_2 capture (NRC, 2004; Parsons 2002a, b; Gray and Tomlinson, 2003; Chiesa *et al.*, 2005; Kreutz *et al.*, 2005), even though this H_2 technology is well established commercially, as noted above. With commercial technology, H_2 with CO_2 capture can be produced via coal gasification in a system similar to a coal IGCC plant with CO_2 capture. In line with the design recommendations for coal IGCC plants described above (IEA GHG, 2003), what follows is the description from a design study of a coal H_2 system that produces, using best available technology, 1070 MW_t of H_2 from high-sulphur (3.4%) bituminous coal (Chiesa *et al.*, 2005; Kreutz *et al.*, 2005). In the base case design, syngas is produced in an entrained flow quench gasifier operated at 7 MPa. The syngas is cooled, cleaned of particulate matter, and shifted (to primarily H_2 and CO_2) in sour water gas shift reactors. After further cooling, H_2S is removed from the syngas using a physical solvent (Selexol). CO_2 is then removed from the syngas, again using Selexol. After being stripped from the solvents, the H_2S is converted to elemental S in a Claus unit and a plant provides tail gas clean-up to remove residual sulphur emissions; and the CO_2 is either vented or dried and compressed to 150 atm for pipeline transport and underground storage. High purity H_2 is extracted at 6 MPa from the H_2-rich syngas via a pressure swing adsorption (PSA) unit. The PSA purge gas is compressed and burned in a conventional gas turbine combined cycle, generating 78 MW_e and 39 MW_e of electricity in excess of onsite electricity needs in the without and with CO_2 capture cases, respectively. For this base case analysis, the effective efficiency of H_2 manufacture was estimated to be 64% with CO_2 vented and 61% with CO_2 captured, while the corresponding emission rates are 16.9 $kgCO_2$ and 1.4 $kgCO_2/kgH_2$, respectively. For the capture case, the CO_2 removal rate was 14.8 $kgCO_2/kgH_2$. Various alternative system configurations were explored. It was found that there are no thermodynamic or cost advantages from increasing the electricity/H_2 output ratio, so this ratio would tend to be determined by relative market demands for electricity and H_2. One potentially significant option for reducing the cost of H_2 with CO_2 capture to about the same level as with CO_2 vented involves H_2S/CO_2 co-capture in a single Selexol unit, as discussed above.

3.5.2.8 *Carbon-based fluid fuels and multi-products*

As discussed in Chapter 2, clean synthetic high H/C ratio fuels can be made from syngas via gasification of coal or other low H/C ratio feedstocks. Potential products include synthetic natural gas, Fischer-Tropsch diesel/gasoline, dimethyl ether, methanol and gasoline from methanol via the Mobil process. A byproduct is typically a stream of relatively pure CO_2 that can be captured and stored.

Coal derived Fischer-Tropsch synfuels and chemicals have been produced on a commercial scale in South Africa; coal methanol is produced in China and at one US plant; and coal SNG is produced at a North Dakota (US) plant (NETL-DOE, 2002). Since 2000, 1.5 $MtCO_2$ yr^{-1} from the North Dakota synthetic natural gas plant (see Figure 3.15) have been transported by pipeline, 300 km to the Weyburn oil field in Saskatchewan, Canada for enhanced oil recovery with CO_2 storage.

Synfuel manufacture involves O_2-blown gasification to make syngas, gas cooling, gas clean-up, water gas shift and acid gas (H_2S/CO_2) removal. Subsequently cleaned syngas is converted catalytically to fuel in a synthesis reactor and unconverted syngas is separated from the liquid fuel product. At this point either most unconverted gas is recycled to the synthesis reactor to generate additional liquid fuel and the remaining unconverted gas is used to make electricity for onsite needs, or syngas is passed only once through the synthesis reactor, and all unconverted syngas is used for other purposes, for example, to make electricity for sale to the electric grid as well as for onsite use. The latter *once through* option is often more competitive as a technology option (Williams, 2000; Gray and Tomlinson, 2001; Larson and Ren, 2003; Celik *et al.*, 2005).

New slurry-phase synthesis reactors make the once through configuration especially attractive for CO-rich (e.g., coal-derived) syngas by making high once through conversion possible. For once through systems, a water gas shift reactor is often placed upstream of the synthesis reactor to generate the H_2/CO ratio that maximizes synfuel conversion in the synthesis reactor. It is desirable to remove most CO_2 from shifted syngas to maximize synthetic fuel conversion. Also, because synthesis catalysts are extremely sensitive to H_2S and various trace contaminants, these must be removed to very low levels ahead of the synthesis reactor. Most trace metals can be removed at low-cost using an activated carbon filter. CO_2 removal from syngas upstream of the synthesis reactor is a low-cost, partial de-carbonization option, especially when H_2S and CO_2 are co-captured and co-stored as an acid gas management strategy (Larson and Ren, 2003). Further de-carbonization can be realized in once through systems, at higher incremental cost, by adding additional shift reactors downstream of the synthesis reactor, recovering the CO_2, and using the CO_2-depleted, H_2-rich syngas to make electricity or some mix of electricity plus H_2 in a 'polygeneration' configuration (see Figure 3.16). The relative amounts of H_2 and electricity produced would depend mainly on relative demands, as there do not seem to be thermodynamic or cost advantages for particular H_2/electricity production ratios (Chiesa *et al.*, 2005; Kreutz *et al.*, 2005). When syngas is de-carbonized both upstream and downstream of the synthesis reactor (see Figure 3.16) it is feasible to capture and store as CO_2 up to 90% of the carbon in the original feedstock except

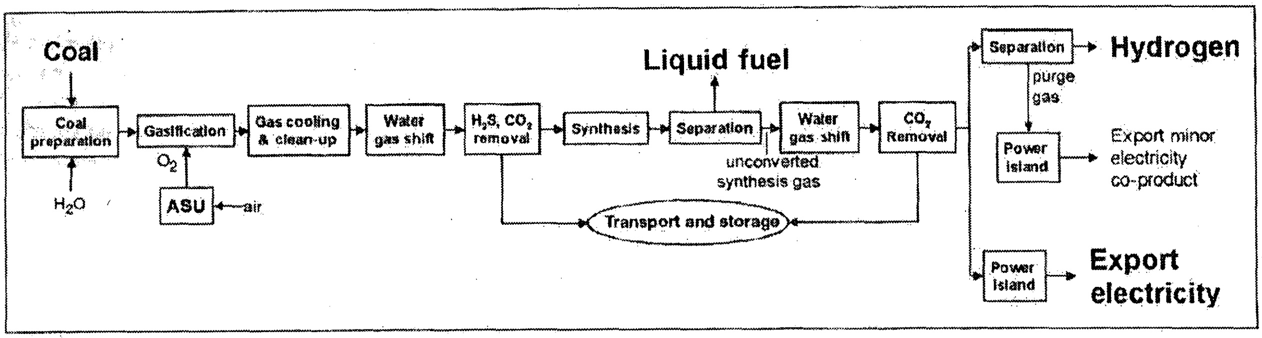


Figure 3.16 Making liquid fuel, electricity and hydrogen from coal via gasification, with CO_2 capture and storage.

that contained in the synthetic fuel produced.

An example of such a system (Celik *et al.*, 2005) is one making 600 MW of dimethyl ether (containing 27% of coal input energy and 20% of coal input carbon) plus 365 MW of electricity (no H_2) from coal. For this system the CO_2 storage rate (equivalent to 74% of C in coal) is 3.8 Mtonnes yr^{-1} (39% from upstream of the synthesis reactor). The estimated fuel cycle-wide GHG emissions for dimethyl ether are 0.9 times those for crude oil-derived diesel and those for electricity are 0.09 times those for a 43% efficient coal-fired power plant with CO_2 vented.

3.5.2.9 Pressure swing adsorption

Pressure Swing Adsorption (PSA) is the system of choice for the purification of syngas, where high purity H_2 is required. However, it does not selectively separate CO_2 from the other waste gases and so for an SMR application the CO_2 concentration in the waste gas would be 40-50% and require further upgrading to produce pure CO_2 for storage. Simultaneous H_2 and CO_2 separation is possible by using an additional PSA section to remove the CO_2 prior to the H_2 separation step, such as the Air Products Gemini Process (Sircar, 1979).

The PSA process is built around adsorptive separations of cyclic character. The cycles consist of two basic steps: adsorption, in which the more adsorbable species are selectively removed from the feed gas and regeneration (desorption), when these species are removed from the adsorbent so that it can be ready for the next cycle. It is possible to obtain useful products during both adsorption and regeneration. The principal characteristic of PSA processes is the use of a decrease in pressure and/or the purge by a less adsorbable gas to clean the adsorbent bed. Apart from adsorption and regeneration, a single commercial PSA cycle consists of a number of additional steps, including co- and counter-current pressurization, pressure equalization and co- and counter-current depressurization. A detailed description of the PSA technique, along with its practical applications can be found elsewhere (Ruthven *et al.*, 1994).

3.5.2.10 Chemical solvent processes

Chemical solvents are used to remove CO_2 from syngas at partial pressures below about 1.5 MPa (Astarita *et al.*, 1983) and are similar to those used in post-combustion capture (see Section 3.3.2.1). The solvent removes CO_2 from the shifted syngas by means of a chemical reaction, which can be reversed by pressure reduction and heating. The tertiary amine methyldiethanolamine (MDEA, see Table 3.2) is widely used in modern industrial processes, due to the high CO_2 loading possible and the low regenerator heating load, relative to other solvents. Hot potassium carbonate (the most common commercial version of which is known as Benfield) was used for CO_2 removal in most hydrogen plants until about 15 years ago.

3.5.2.11 Physical solvent processes

Physical solvent (or absorption) processes are mostly applicable to gas streams which have a high CO_2 partial pressure and/or a high total pressure. They are often used to remove the CO_2 from the mixed stream of CO_2 and H_2 that comes from the shift reaction in pre-combustion CO_2 capture processes, such as product from partial oxidation of coal and heavy hydrocarbons.

The leading physical solvent processes are shown in Table 3.2. The regeneration of solvent is carried out by release of pressure at which CO_2 evolves from the solvent, in one or more stages. If a deeper regeneration is required the solvent would be stripped by heating. The process has low energy consumption, as only the energy for pressurizing the solvent (liquid pumping) is required.

The use of high sulphur fossil fuels in a pre-combustion capture process results in syngas with H_2S. Acid gas components must be removed. If transport and storage of mixed CO_2 and H_2S is possible then both components can be removed together. Sulphinol was developed to achieve significantly higher solubilities of acidic components compared to amine solvents, without added problems of excessive corrosion, foaming, or solution degradation. It consists of a mixture of sulpholane (tetrahydrothiophene 1,1-dioxide), an alkanolamine and water in various proportions depending on the duty. If pure CO_2 is required, then a selective process is required using physical solvents - often Rectisol or Selexol. The H_2S must be separated at sufficiently high concentration (generally >50%) to be treated in a sulphur recovery plant.

3.5.2.12 Effect on other pollutants

Pre-combustion capture includes reforming, partial oxidation or gasification. In order to maintain the operability of the catalyst of reformers, sulphur (H_2S) has to be removed prior to reforming. In gasification, sulphur can be captured from the syngas, and in the case when liquid or solid fuels are gasified, particulates, NH_3, COS and HCN are also present in the system that need to be removed. In general, all of these pollutants can be removed from a high-pressure fuel gas prior to combustion, where combustion products are diluted with nitrogen and excess oxygen. In the combustion of hydrogen or a hydrogen-containing fuel gas, NO_x may be formed. Depending upon combustion technology and hydrogen fraction, the rate at which NO_x is formed may vary. If the volumetric fraction of hydrogen is below approximately 50-60%, NO_x formation is at the same level as for natural gas dry low-NO_x systems (Todd and Battista, 2001).

In general, with the exception of H_2S that could be co-removed with CO_2, other pollutants identified above are separated in additional pretreatment operations, particularly in systems that gasify liquid or solid fuels. High temperature pretreatment operations for these multi-pollutants that avoid cooling of the syngas have the advantage of improving the cycle efficiency of the overall gasification process, but these separation processes have not been commercially demonstrated.

Although it is not yet regulated as a 'criteria pollutant', mercury (Hg), is currently the focus of considerable concern as a pollutant from coal power systems. For gasification systems Hg can be recovered from syngas at ambient temperatures at very low-cost, compared to Hg recovery from flue gases (Klett *et al.*, 2002).

3.5.3 *Emerging technologies*

Emerging options in both natural gas reforming and coal gasification incorporate novel combined reaction/separation systems such as sorption-enhanced reforming and sorption-enhanced water gas shift, membrane reforming and membrane water gas shift. Finally there is a range of technologies that make use of the carbonation of CaO for CO_2 capture.

3.5.3.1 Sorption enhanced reaction

A concept called Sorption Enhanced Reaction (SER) uses a packed bed containing a mixture of a catalyst and a selective adsorbent to remove CO_2 from a high temperature reaction zone, thus driving the reaction to completion. (Hufton *et al.*, 1999). The adsorbent is periodically regenerated by using a pressure swing, or temperature swing adsorption system with steam regeneration (Hufton *et al.*, 2005).

High temperature CO_2 adsorbents such as hydrotalcites (Hufton *et al.*, 1999) or lithium silicate (Nakagawa and Ohashi, 1998) can be mixed with a catalyst to promote either the steam methane reforming reaction (Reaction 1) or water gas shift reaction (Reaction 3) producing pure hydrogen and pure CO_2 in a single process unit. The continuous removal of the CO_2 from the reaction products by adsorption shifts each reaction towards completion.

The SER can be used to produce hydrogen at 400-600°C to fuel a gas turbine combined cycle power generation system. A design study based on a General Electric 9FA gas turbine with hot hydrogen, produced from an air blown ATR with a sorption enhanced water gas shift reactor, gave a theoretical net efficiency of 48.3% with 90% CO_2 capture at 99% purity and 150 bar pressure (Hufton *et al.*, 2005). The process is currently at the pilot plant stage.

3.5.3.2 Membrane reactors for hydrogen production with CO_2 capture

Inorganic membranes with operating temperatures up to 1000°C offer the possibility of combining reaction and separation of the hydrogen in a single stage at high temperature and pressure to overcome the equilibrium limitations experienced in conventional reactor configurations for the production of hydrogen. The combination of separation and reaction in membrane steam reforming and/or membrane water gas shift offers higher conversion of the reforming and/or shift reactions due to the removal of hydrogen from these equilibrium reactions as shown in Reactions (1) and (3) respectively. The reforming reaction is endothermic and can, with this technique, be forced to completion at lower temperature than normal (typically 500-600°C). The shift reaction being exothermic can be forced to completion at higher temperature (500-600°C).

Another reason to incorporate H_2 separation membranes in the hydrogen production system is that CO_2 is also produced without the need for additional separation equipment. Membrane reactors allow one-step reforming, or a single intermediate water gas shift reaction, with hydrogen separation (the permeate) leaving behind a retentate gas which is predominantly CO_2 and a small amount of non-recovered hydrogen and steam. This CO_2 remains at the relatively high pressure of the reacting system (see Figure 3.17). Condensation of the steam leaves a concentrated CO_2 stream at high pressure, reducing the compression energy for transport and storage. Membrane reforming will benefit from high-pressure operation due to the increased H_2 partial pressure differential across the membrane which is the driving force for hydrogen permeation. Therefore membrane reactors are also seen as a good option for pre-combustion de-carbonization where a low-pressure hydrogen stream for fuel gas and a high-pressure CO_2-rich stream for transport and storage are required. The use of the membrane reformer reactor in a gas turbine combined cycle means that the hydrogen needs to be produced at such pressure that the significant power consumption for the hydrogen compression is avoided. This could be done by increasing the operating pressure of the membrane reactor or by using a sweep gas, for instance steam, at the permeate side of the membrane (Jordal *et al.*, 2003).

For these membrane reactor concepts, a hydrogen selective membrane capable of operating in a high-temperature, high-pressure environment is needed. In the literature a number of membrane types have been reported that have these capabilities and these are listed in Table 3.3. Microporous inorganic membranes based upon surface diffusion separation exhibit rather low separation factors (e.g., H_2/CO_2 separation factor of 15). However, the separation ability of the current commercially available gamma-alumina and silica microporous membranes (which have better separation factors, up to 40) depends upon the stability of the membrane pore size, which is adversely

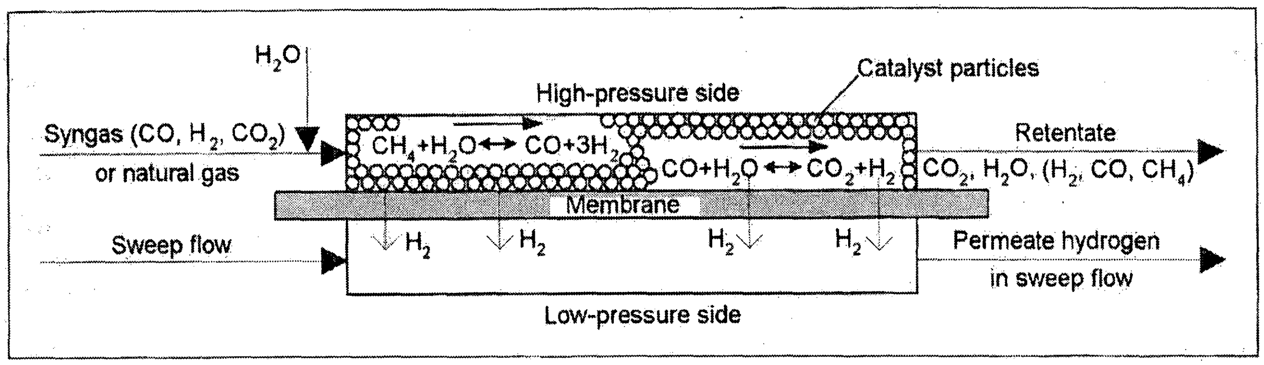


Figure 3.17 Operating principle of a membrane reactor.

Table 3.3 Membrane materials, operating conditions and characteristics for H_2 separation.

	Microporous Ceramic	**Microporous Ceramic**	**Microporous Carbon**	**Zeolites**	**Metal**
Membrane material	Alumina	Silica	Carbon	Silica (Alumina)	Pd/Ag
Temperature range (°C)	<500	<400	<400	<500 - 700	<600
Pressure range (bar)	>100	>100	10	>100	>100
Pore size distribution (nm)	0.7-2	0.7-2	0.7-2	0.3-0.7	no pores
Separation factors (H_2/CO_2)	15	15	15-25	50	100
Permeability (mol $m^{-2}s^{-1}Pa^{-1}$)	10^{-6}	10^{-6}	10^{-7}	10^{-6}	10^{-7}-10^{-6}
Experim. temp. (°C)	200	200	300-400	300-400	300-400
Pre-clean-up requirements				S	S, HCl, HF (?)
Chemical resistance problem		H_2O	O_2	S	S, HCl, HF
Geometry	Top layer tube	Top layer tube	Top layer tube/fibre	Top layer tube	Top layer tube/plate
Configuration	Cascade/recycle/ once through	Cascade/recycle/ once through	Cascade/recycle/ once through	Once through	Once through
Lifetime	+	-	+	+	0
Costs (US\$ m^{-2})	4250	4250	3000?	4000-4250	4000-4250
Scalability	0	0	0	-	0

affected by the presence of steam in the feed streams. The dense ceramic membranes based on inorganic perovskite oxides (also called proton conducting) need high temperatures, higher than 800°C, to achieve practical hydrogen flux rates. Palladium-based dense membranes are also known for their high hydrogen selectivity and permeability over other gases in the temperature range 300°C-600°C that is appropriate for these two reactions. Palladium alloy tubes have been available for several decades, but for CCS applications they are too expensive due to the membrane thickness needed for structural stability and consequently low hydrogen flux rates. In order to be suitable for the target application, a hydrogen separation membrane must have adequate selectivity and flux rate and must be stable in the reducing coal gas or fuel-reforming environment containing steam and hydrogen sulphide.

A number of membrane reactor developments have been reported for hydrogen production with CO_2 capture. Several groups have evaluated methane steam reforming membrane reactors based on palladium alloy membranes (Middleton *et al.*, 2002, Damle and Dorchak, 2001). These evaluations showed that membrane reactors could achieve 90% CO_2 recovery and that at this moment the projected cost is nearly identical to that for a conventional system. However, a cost-reduction can be achieved by either reducing the material cost of the membrane or by increasing the permeability. Similar evaluations of membrane reactors for the shift conversion and separation of CO_2 from syngas produced from heavy feeds by gasification have been reported (Bracht *et al.*, 1997; Middleton 2002; Lowe *et al.*, 2003). For these gasifier systems the membrane reactors could reduce the costs for capturing CO_2 and the cost reduction would be more significant if they could be made sulphur tolerant.

3.5.3.3 Microchannel reformer

Microreactor technology can be used to produce a SMR, or low temperature air-based POX system using a multichannel plate-fin heat exchanger, fabricated in stainless steel or high nickel alloy by vacuum brazing or diffusion bonding.

An SMR reactor consists of alternate passages having fins, which are coated with catalyst or porous catalyst insets. Heat is produced by catalytic combustion of fuel gas premixed with air and transferred by conduction to the adjacent passage fed with the steam/hydrocarbon mixture, where the reforming reaction takes place (Babovic *et al.*, 2001). Very compact high efficiency systems can be produced. Although these units are being currently developed by a number of groups for small-scale H_2 production for fuel cell applications, they also show promise in larger H_2 plants.

3.5.3.4 Conversion to hydrogen and carbon

Thermal cracking or pyrolysis of methane is the reaction where methane reacts to carbon and hydrogen through:

Methane pyrolysis:

$$CH_4 \rightarrow C + 2\,H_2 \qquad (4)$$

The main advantage of the process is that it can potentially yield a clean gas (free of carbon oxides) that could be used directly for power production, but a disadvantage is that the chemical energy from the oxidation of carbon to CO_2 is not released. The cracking reaction is endothermic and so heat has to be supplied to the reaction. If the natural gas is converted fully, the theoretical yield of hydrogen corresponds to 60% of the heating value of the natural gas. The amount of carbon, which can be obtained, corresponds to 49% of the heating value, with the extra 9% of the energy in this calculation being provided as endothermic heat shown by reaction (4) above. Therefore full conversion can be achieved only if heat is supplied from an external source. If full conversion of methane is not achieved, the remaining methane will be combusted to produce heat. There are many different methods under development for reactors based on this principle, including thermal catalytic, thermal non-catalytic and plasma cracking.

In the plasma cracking process natural gas or other hydrocarbons are supplied to a plasma reactor where the hydrocarbons are cracked under pyrolysis conditions (i.e., in absence of oxides, e.g., steam, which can supply oxygen to form CO or CO_2). The plasma arc, for which electricity is used, supplies the heat for the cracking reaction. Advantages of the process are its flexibility with respect to the fuel and the high quality carbon black which can be produced. Two small-scale plasma cracking processes for hydrogen/syngas production have been in development. The Glid Arc process has been developed by the Canadian Synergy Technologies Corporation. The second process is the Kvaerner CB&H process. Kvaerner has reported results for a pilot plant producing 1000 Nm^3 hydrogen per hour and 270 kg or 500 kg carbon black using natural gas and aromatic oil respectively (IEA GHG, 2001).

3.5.3.5 Technologies based on calcium oxide

There is a range of pre-combustion systems that make use of the carbonation reaction of CaO at high pressures and temperatures, to further integrate the gasification of the fuel (if solid), the shift reaction, and in-situ CO_2 removal with CaO. The overall reaction aimed in the system is:

Carbonation of calcium oxide:

$$CaO + C + 2\,H_2O \rightarrow CaCO_3 + 2H_2 \qquad (5)$$

The regeneration of the sorbent produces pure CO_2 when carried out in a separate reactor by calcining $CaCO_3$. A range of systems can be developed under this general reaction scheme depending on the technology adopted for gasification, carbonation-calcination, hydrogen utilization route and storage option for CO_2. The first of these concepts was proposed at the Los Alamos National Laboratory (USA) and is currently under development as the Zero Emission Coal Alliance (ZECA) process. The full system includes (Lackner *et al.*, 2001) a hydro-gasification reactor, solid oxide fuel cell and a technology for mineral carbonation. However, the fuel cell will require more development and mineral carbonation is only at the laboratory investigation stage (see Section 7.2 for a discussion of mineral carbonation).

The HyPrRing process (Lin *et al.*, 2002) is being developed by the Center for Coal Utilization of Japan. It integrates gasification, reforming and *in situ* CO_2 capture in a single reactor at pressures above 12 MPa and temperature above 650°C. Projects in Norway using natural gas and in Germany using brown coal (Bandi *et al.*, 2002) are also underway developing pre-combustion systems using capture of CO_2 with CaO. Finally, General Electric (Rizeq *et al.*, 2002) is developing an innovative system involving the capture of CO_2 in the gasification reactor by a high temperature sorbent and with calcination in a separate reactor by burning part of the fuel with an oxygen carrier.

All these systems are at an early stage of development. Detailed process simulations show that the efficiencies are potentially high because most of the energy employed for sorbent regeneration is effectively transferred to the H_2 generated in reaction (5). The systems are aimed at very large-scale generation of electricity and/or H_2 and cement production (from the deactivated sorbent, CaO). However, many uncertainties remain concerning the performance of the individual units and their practical integration. The main challenge may be the regeneration of the sorbent at very high temperatures (>900°C), to produce a pure stream of CO_2. Another is the operating conditions to achieve sufficient conversion towards hydrogen, without the use of a catalyst for the shift reaction.

3.5.4 Enabling technologies

The performance and cost of a pre-combustion capture system is linked to the availability of the enabling technologies that complete the system. In this section we consider the availability of industrial systems, to produce heat from the de-carbonized fuel and gas turbines and fuel cells to produce power.

3.5.4.1 Use of de-carbonized fuel in industrial systems

The use of hydrogen as a fuel for conventional fired heaters and boilers is considered to be proven and indeed it is practiced at certain industrial sites. There is a very large stock of capital equipment of this type and so the use of hydrogen as a fuel might be considered a valuable technology option in a carbon-constrained world. A study (IEA GHG, 2000c) has looked at the cost of converting an existing refinery to use hydrogen fuel.

3.5.4.2 Use of de-carbonized fuel in gas turbine systems

There is extensive commercial experience with hydrogen-rich fuel gas firing in gas turbines. For example, General Electric reports over 450,000 hours of operating experience with high hydrogen (52-95% by volume) content fuel gas in gas turbines (Shilling and Jones, 2003). Unfortunately, most of that experience is for 'refinery gas' where methane is the other main component of the fuel gas and is utilized in older lower firing temperature gas turbines, not the state-of-the-art over 1300°C gas turbines normally considered for large de-carbonization power plants.

Norsk Hydro and General Electric collaborated to perform full-scale combustion system testing for modern gas turbines firing hydrogen-rich gas with combustion exit temperatures of above 1400°C (Todd and Battista, 2001). The results showed good combustion conditions with low NO_x emission and acceptable hot metal temperatures for mixtures with 54-77% by volume hydrogen with most of the additional gas being nitrogen. Dilution of the hydrogen with nitrogen or steam reduces the NO_x emission.

For pre-combustion capture of CO_2 from natural gas, air-blown gasification or autothermal reforming is usually preferred (IEA GHG, 2000b; Wilkinson and Clarke, 2002). Nitrogen dilution of the hydrogen required for firing in modern gas turbines comes from the gasification air. High-pressure air is usually extracted from the gas turbine to feed the air-blown gasifier, or autothermal reformer to reduce costs and avoid a separate air compressor. The balance between the amount of air withdrawn from the gas turbine and the amount provided from a separate air compressor is determined by the particular characteristics of the gas turbine used. Some gas turbines can accept a higher ratio of expander to compressor flow, allowing greater volumes of dilution gas or smaller air-side draw flow and giving higher power output.

For pre-combustion capture of CO_2 from coal, oxygen-blown gasification is usually preferred (IEA GHG, 2003). Nitrogen dilution of the hydrogen required for firing in modern gas turbines comes from the cryogenic air separation unit (used to make the oxygen; see Section 3.4.5.1). The nitrogen is added to the hydrogen after the gasification, CO shifting and CO_2 capture to reduce the equipment sizes and cost. High-pressure air is usually extracted from the gas turbine to supply a higher than normal pressure cryogenic air separation unit to reduce costs plus air, oxygen and nitrogen compression power. An alternative IGCC scheme that incorporates newly emerging ion transport membranes for oxygen production is also described below in Section 3.5.4.3.

3.5.4.3 Syngas production using oxygen membranes

Oxygen required for a coal-fired IGCC process (Section 3.5.2.6) can be generated in an oxygen transport membrane system by using a heated, high-pressure air stream produced by heating the discharge air from the compressor section of a gas turbine (Allam *et al.*, 2002), typically at 1.6 MPa or 420°C, to the precise inlet temperature of the oxygen transport membrane module which is above 700°C. The oxygen, which permeates to the low-pressure side passes through a heat recovery section and is compressed to the final pressure of use. The O_2 depleted air leaving the oxygen transport membrane module then enters the gas turbine combustor where it is used to burn fuel before entering the gas turbine expander at the required temperature. Note that due to the necessity to have excess air in a gas turbine to limit turbine inlet temperature, removing one mole of oxygen can be compensated by injection of the equivalent thermal capacity of steam to maintain gas turbine power output. Studies have been carried out (Armstrong *et al.*, 2002) to compare oxygen transport membrane and cryogenic oxygen production in an IGCC power plant using coal as fuel. The oxygen plant projected cost was reduced by 35% and the power consumption by 37%. An LHV efficiency of 41.8% without CO_2 capture and compression is reported for this cycle compared to 40.9% when a conventional cryogenic oxygen plant is used.

For autothermal reforming or the partial oxidation of natural gas, if the permeate side of the oxygen transport membrane is exposed to a natural gas plus water vapour stream in the presence of a reforming catalyst, the oxygen will react as it leaves the membrane in an exothermic reaction (Dyer *et al.*, 2001; Carolan *et al.*, 2001), which will provide heat for the endothermic steam/natural gas reforming reaction. The oxygen partial pressure at these highly-reducing, high temperature conditions is extremely low, allowing heated air at close to atmospheric pressure to be used on the feed side of the membrane while producing a H_2 + CO mixture at high pressure from the permeate side. This system can be used to produce H_2 following CO shift reaction and CO_2 removal.

3.5.4.4 Chemical looping gasification/reforming

The chemical looping concept described in 3.4.6 is being considered for reforming of a fuel to produce H_2 and CO (Zafar *et al.*, 2005). When the amount of oxygen brought by the metal oxide into the reduction reactor is below stoichiometric requirements, the chemical reaction with the fuel produces H_2 and CO. The reaction products may subsequently be shifted with steam to yield CO_2 and more H_2.

3.5.4.5 Use of de-carbonized fuel in fuel cells

Fuel cells offer the possibility for highly efficient power production since the conversion process is not controlled by heat to work Carnot cycle restrictions (Blomen and Mugerwa, 1993). In general fuel cells feature the electrochemical oxidation of gaseous fuels directly into electricity, avoiding the mixture of the air and the fuel flows and thus the dilution with nitrogen and excess oxygen of the oxidized products (Campanari, 2002). As a result, the anode outlet stream of a fuel cell already has a very high CO_2 content that simplifies the CO_2 capture subsystem. The fuel is normally natural gas, though some concepts can also be incorporated into coal gasification systems. The systems concepts can be classified into two main groups (Goettlicher, 1999):

- Systems with pre-fuel cell CO_2 capture;
- Systems with post-fuel cell CO_2 capture.

In pre-fuel cell CO_2 capture systems (see Figure 3.18a) the fuel is first converted into hydrogen using steam reforming or coal gasification, followed by the water gas shift conversion. This system approach has been first proposed both for low temperature and for high temperature fuel cells.

The post-fuel cell capture system (see Figure 3.18b) is proposed for high temperature fuel cell systems (Dijkstra and Jansen, 2003). These systems make use of the internal reforming capabilities of the high temperature fuel cells resulting in an anode off-gas that has a high CO_2-content, but also contains H_2O and unconverted CO and H_2. The water can easily be removed by conventional techniques (cooling, knock-out, additional drying). Oxidizing the H_2 and CO from the (SOFC) anode with air will result in a too high dilution of the stream with nitrogen.

Haines (1999) chooses to use an oxygen-transport membrane reactor placed after the SOFC. The anode off-gas is fed to one side of the membrane, the cathode off-gas is fed to the other side of the membrane. The membrane is selective to oxygen, which permeates from the cathode off-gas stream to the anode-off gas. In the membrane unit the H_2 and CO are oxidized. The retenate of the membrane unit consist of CO_2 and water. Finally a concept using a water gas shift membrane reactor has been proposed (Jansen and Dijkstra, 2003).

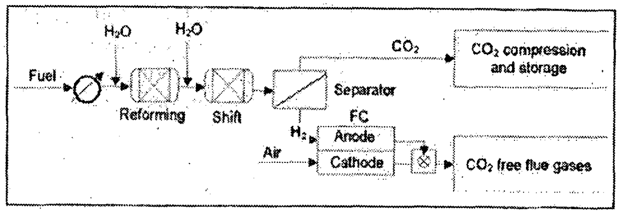


Figure 3.18a Fuel cell system with pre-fuel cell CO_2 capture. The carbon-containing fuel is first completely converted into a mixture of hydrogen and CO_2. Hydrogen and CO_2 are then separated and the H_2-rich fuel is oxidized in the fuel cell to produce electricity. The CO_2 stream is dried and compressed for transport and storage.

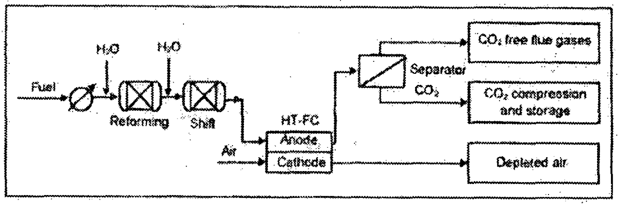


Figure 3.18b Fuel cell system with post-fuel cell CO_2 capture. The carbon-containing fuel is first converted into a syngas. The syngas is oxidized in the fuel cell to produce electricity. At the outlet of the fuel cell CO_2 is separated from the flue gas, dried and compressed for transport and storage.

3.5.5 *Status and outlook*

This section reviewed a wide variety of processes and fuel conversion routes that share a common objective: to produce a cleaner fuel stream from the conversion of a raw carbonaceous fuel into one that contains little, or none, of the carbon contained in the original fuel. This approach necessarily involves the separation of CO_2 at some point in the conversion process. The resulting H_2-rich fuel can be fed to a hydrogen consuming process, oxidized in a fuel cell, or burned in the combustion chamber of a gas turbine to produce electricity. In systems that operate at high pressure, the energy conversion efficiencies tend to be higher when compared to equivalent systems operating at low pressures following the combustion route, but these efficiency improvements are often obtained at the expense of a higher complexity and capital investment in process plants (see Section 3.7).

In principle, all pre-combustion systems are substantially similar in their conversion routes, allowing for differences that arise from the initial method employed for syngas production from gaseous, liquid or solid fuels and from the subsequent need to remove impurities that originate from the fuel feed to the plant. Once produced, the syngas is first cleaned and then reacted with steam to produce more H_2 and CO_2. The separation of these two gases can be achieved with well-known, commercial absorption-desorption methods, producing a CO_2 stream suitable for storage. Also, intense R&D efforts worldwide are being directed towards the development of new systems that combine CO_2 separation with some of the reaction steps, such as the steam reforming of natural gas or water gas shift reaction stages, but it is not yet clear if these emerging concepts (see Section 3.5.3) will deliver a lower CO_2 capture cost.

In power systems, pre-combustion CO_2 capture in natural gas combined cycles has not been demonstrated. However, studies show that based on current state of the art gas turbine combined cycles, pre-combustion CO_2 capture will reduce the efficiency from 56% LHV to 48% LHV (IEA, 2000b). In natural gas combined cycles, the most significant area for efficiency improvement is the gas turbine and it is expected that by 2020, the efficiency of a natural gas combined cycle could be as high as 65% LHV (IEA GHG, 2000d). For such systems the efficiency with CO_2 capture would equal the current state-of-the-art efficiency for plants without CO_2 capture, that is, 56% LHV.

Integrated Gasification Combined Cycles (IGCC) are large scale, near commercial examples of power systems that can be implemented with heavy oil residues and solid fuels like coal and petroleum coke. For the embryonic coal-fired IGCC technology with the largest unit rated at 331 MW_e, future improvements are expected. A recent study describes improvements potentially realisable for bituminous coals by 2020 that could reduce both energy and cost-of-electricity penalties for CO_2 capture to 13% compared to a same base plant without capture. For such systems the generation efficiency with capture would equal the best efficiency realisable today without CO_2 capture (i.e., 43% LHV; IEA GHG, 2003). Notably, all the innovations considered, with the exception of ion transport membrane technology for air separation (which is motivated by many market drivers other than IGCC needs) involve 'non- breakthrough' technologies, with modest continuing improvements in components that are already established commercially - improvements that might emerge as a natural result of growing commercial experience with IGCC technologies.

All fuel cell types are currently in the development phase. The first demonstration systems are now being tested, with the largest units being at the 1 MW scale. However, it will take at least another 5 to 10 years before these units become commercially available. In the longer term, these highly efficient fuel cell systems are expected to become competitive for power generation. Integrating CO_2 capture in these systems is relatively simple and therefore fuel cell power generation systems offer the prospect of reducing the CO_2 capture penalty in terms of efficiency and capture costs. For instance, for high temperature fuel cell systems without CO_2 capture, efficiencies that exceed 67% are calculated with an anticipated 7% efficiency reduction when CO_2 capture is integrated into the system (Jansen and Dijkstra, 2003). However, fuel cell systems are too small to reach a reasonable level of CO_2 transport cost (IEA GHG, 2002a), but in groups of a total of capacity 100MWe, the cost of CO_2 transport is reduced to a more acceptable level.

Most studies agree that pre-combustion systems may be better suited to implement CO_2 capture at a lower incremental cost compared to the same type of base technology without capture (Section 3.7), but with a key driver affecting implementation being the absolute cost of the carbon emission-free product, or service provided. Pre-combustion systems also have a high strategic importance, because their capability to deliver, in a large scale and at high thermal efficiencies, a suitable mix of electricity, hydrogen and lower carbon-containing fuels or chemical feedstocks in an increasingly carbon-constrained world.

3.6 Environmental, monitoring, risk and legal aspects of capture systems

The previous sections of this chapter focused on each of the major technologies and systems for CO_2 capture. Here we summarize the major environmental, regulatory and risk issues associated with the use of CO_2 capture technology and the handling of carbon dioxide common to all of these systems. Issues related to the subsequent transport and storage of carbon dioxide are discussed in Chapters 4 to 7.

3.6.1 Emissions and resource use impacts of CO_2 capture systems

3.6.1.1 Overview of emissions from capture systems

Plants with CO_2 capture would produce a stream of concentrated CO_2 for storage, plus in most cases a flue gas or vent gas emitted to the atmosphere and liquid wastes. In some cases solid wastes will also be produced.

The captured CO_2 stream may contain impurities which would have practical impacts on CO_2 transport and storage systems and also potential health, safety and environmental impacts. The types and concentrations of impurities depend on the type of capture process, as shown in Table 3.4, and detailed plant design. The major impurities in CO_2 are well known but there is little published information on the fate of any trace impurities in the feed gas such as heavy metals. If substances are captured along with the CO_2 then their net emissions to the atmosphere will be reduced, but impurities in the CO_2 may result in environmental impacts at the storage site.

CO_2 from most capture processes contains moisture, which has to be removed to avoid corrosion and hydrate formation during transportation. This can be done using conventional

Table 3.4 Concentrations of impurities in dried CO_2, % by volume (Source data: IEA GHG, 2003; IEA GHG, 2004; IEA GHG, 2005).

	SO_2	NO	H_2S	H_2	CO	CH_4	$N_2/Ar/O_2$	Total
COAL FIRED PLANTS								
Post-combustion capture	<0.01	<0.01	0	0	0	0	0.01	0.01
Pre-combustion capture (IGCC)	0	0	0.01-0.6	0.8-2.0	0.03-0.4	0.01	0.03-0.6	2.1-2.7
Oxy-fuel	0.5	0.01	0	0	0	0	3.7	4.2
GAS FIRED PLANTS								
Post-combustion capture	<0.01	<0.01	0	0	0	0	0.01	0.01
Pre-combustion capture	0	0	<0.01	1.0	0.04	2.0	1.3	4.4
Oxy-fuel	<0.01	<0.01	0	0	0	0	4.1	4.1

a. The SO_2 concentration for oxy-fuel and the maximum H_2S concentration for pre-combustion capture are for cases where these impurities are deliberately left in the CO_2, to reduce the costs of capture (see Section 3.6.1.1). The concentrations shown in the table are based on use of coal with a sulphur content of 0.86%. The concentrations would be directly proportional to the fuel sulphur content.

b. The oxy-fuel case includes cryogenic purification of the CO_2 to separate some of the N_2, Ar, O_2 and NO_x. Removal of this unit would increase impurity concentrations but reduce costs.

c. For all technologies, the impurity concentrations shown in the table could be reduced at higher capture costs.

processes and the costs of doing so are included in published costs of CO_2 capture plants.

CO_2 from post-combustion solvent scrubbing processes normally contains low concentrations of impurities. Many of the existing post-combustion capture plants produce high purity CO_2 for use in the food industry (IEA GHG, 2004).

CO_2 from pre-combustion physical solvent scrubbing processes typically contains about 1-2% H_2 and CO and traces of H_2S and other sulphur compounds (IEA GHG, 2003). IGCC plants with pre-combustion capture can be designed to produce a combined stream of CO_2 and sulphur compounds, to reduce costs and avoid the production of solid sulphur (IEA GHG, 2003). Combined streams of CO_2 and sulphur compounds (primarily hydrogen sulphide, H_2S) are already stored, for example in Canada, as discussed in Chapter 5. However, this option would only be considered in circumstances where the combined stream could be transported and stored in a safe and environmentally acceptable manner.

The CO_2-rich gas from oxy-fuel processes contains oxygen, nitrogen, argon, sulphur and nitrogen oxides and various other trace impurities. This gas will normally be compressed and fed to a cryogenic purification process to reduce the impurities concentrations to the levels required to avoid two-phase flow conditions in the transportation pipelines. A 99.99% purity could be produced by including distillation in the cryogenic separation unit. Alternatively, the sulphur and nitrogen oxides could be left in the CO_2 fed to storage in circumstances where that is environmentally acceptable as described above for pre-combustion capture and when the total amount of all impurities left in the CO_2 is low enough to avoid two-phase flow conditions in transportation pipelines.

Power plants with CO_2 capture would emit a CO_2-depleted flue gas to the atmosphere. The concentrations of most harmful substances in the flue gas would be similar to or lower than in the flue gas from plants without CO_2 capture, because CO_2 capture processes inherently remove some impurities and some other impurities have to be removed upstream to enable the CO_2 capture process to operate effectively. For example, post-combustion solvent absorption processes require low concentrations of sulphur compounds in the feed gas to avoid excessive solvent loss, but the reduction in the concentration of an impurity may still result in a higher rate of emissions per kWh of product, depending upon the actual amount removed upstream and the capture system energy requirements. As discussed below (Section 3.6.1.2), the latter measure is more relevant for environmental assessments. In the case of post-combustion solvent capture, the flue gas may also contain traces of solvent and ammonia produced by decomposition of solvent.

Some CO_2 capture systems produce solid and liquid wastes. Solvent scrubbing processes produce degraded solvent wastes, which would be incinerated or disposed of by other means. Post-combustion capture processes produce substantially more degraded solvent than pre-combustion capture processes. However, use of novel post-combustion capture solvents can significantly reduce the quantity of waste compared to MEA solvent, as discussed in Section 3.3.2.1. The waste from MEA scrubbing would normally be processed to remove metals and then incinerated. The waste can also be disposed of in cement kilns, where the waste metals become agglomerated in the clinker (IEA GHG, 2004). Pre-combustion capture systems periodically produce spent shift and reforming catalysts and these would be sent to specialist reprocessing and disposal facilities.

3.6.1.2 Framework for evaluating capture system impacts

As discussed in Chapter 1, the framework used throughout this report to assess the impacts of CO_2 capture and storage is based on the material and energy flows needed to produce a unit of product from a particular process. As seen earlier in this chapter, CO_2 capture systems require an increase in energy use for their operation. As defined in this report (see Section 1.5 and Figure 1.5), the energy requirement associated with CO_2 capture is expressed as the additional energy required to produce a unit of useful product, such as a kilowatt-hour of electricity (for the case of a power plant). As the energy and resource requirement for CO_2 capture (which includes the energy needed to compress CO_2 for subsequent transport and storage) is typically much larger than for other emission control systems, it has important implications for plant resource requirements and environmental emissions when viewed from the 'systems' perspective of Figure 1.5.

In general, the CCS energy requirement per unit of product can be expressed in terms of the change in net plant efficiency (η) when the reference plant without capture is equipped with a CCS system:[1]

$$\Delta E = (\eta_{ref} / \eta_{ccs}) - 1 \qquad (6)$$

where ΔE is the fractional increase in plant energy input per unit of product and η_{ccs} and η_{ref} are the net efficiencies of the capture plant and reference plant, respectively. The CCS energy requirement directly determines the increases in plant-level resource consumption and environmental burdens associated with producing a unit of useful product (like electricity) while capturing CO_2. In the case of a power plant, the larger the CCS energy requirement, the greater the increases per kilowatt-hour of in-plant fuel consumption and other resource requirements (such as water, chemicals and reagents), as well as environmental releases in the form of solid wastes, liquid wastes and air pollutants not captured by the CCS system. The magnitude of ΔE also determines the magnitude of additional upstream environmental impacts associated with the extraction, storage and transport of additional fuel and other resources consumed at the plant. However, the additional energy for these upstream activities is not normally included in the reported

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[1] A different measure of the 'energy penalty' commonly reported in the literature is the fractional decrease in plant output (plant derating) for a fixed energy input. This value can be expressed as: $\Delta E^* = 1 - (\eta_{ccs}/\eta_{ref})$. Numerically, ΔE^* is smaller than the value of ΔE given by Equation (6). For example, a plant derating of $\Delta E^* = 25\%$ corresponds to an increase in energy input per kWh of $\Delta E = 33\%$.

energy requirements for CO_2 capture systems.[2]

Recent literature on CO_2 capture systems applied to electric power plants quantifies the magnitude of CCS energy requirements for a range of proposed new plant designs with and without CO_2 capture. As elaborated later in Section 3.7 (Tables 3.7 to 3.15), those data reveal a wide range of ΔE values. For new supercritical pulverized coal (PC) plants using current technology, these ΔE values range from 24-40%, while for natural gas combined cycle (NGCC) systems the range is 11%–22% and for coal-based gasification combined cycle (IGCC) systems it is 14%–25%. These ranges reflect the combined effects of the base plant efficiency and capture system energy requirements for the same plant type with and without capture.

3.6.1.3 *Resource and emission impacts for current systems*

Only recently have the environmental and resource implications of CCS energy requirements been discussed and quantified for a variety of current CCS systems. Table 3.5 displays the assumptions and results from a recent comparison of three common fossil fuel power plants employing current technology to capture 90% of the CO_2 produced (Rubin *et al.*, 2005). Increases in specific fuel consumption relative to the reference plant without CO_2 capture correspond directly to the ΔE values defined above. For these three cases, the plant energy requirement per kWh increases by 31% for the PC plant, 16% for the coal-based IGCC plant and 17% for the NGCC plant. For the specific examples used in Table 3.5, the increase in energy consumption for the PC and NGCC plants are in the mid-range of the values for these systems reported later in Tables 3.7 to 3.15 (see also Section 3.6.1.2), whereas the IGCC case is nearer the low end of the reported range for such systems. As a result of the increased energy input per kWh of output, additional resource requirements for the PC plant include proportionally greater amounts of coal, as well as limestone (consumed by the FGD system for SO_2 control) and ammonia (consumed by the SCR system for NO_x control). All three plants additionally require more sorbent make-up for the CO_2 capture units. Table 3.5 also shows the resulting increases in solid residues for these three cases. In contrast, atmospheric emissions of CO_2 decrease sharply as a result of the CCS systems, which also remove residual amounts of other acid gases, especially SO_2 in flue gas streams. Thus, the coal combustion system shows a net reduction in SO_2 emission rate as a result of CO_2 capture. However, because of the reduction in plant efficiency, other air emission rates per kWh increase relative to the reference plants without capture. For the PC and NGCC systems, the increased emissions of ammonia are a result of chemical reactions in the amine-based capture process. Not included in this analysis are the incremental impacts of upstream operations such as mining, processing and transport of fuels and other resources. Other studies, however, indicate that these impacts, while not insignificant, tend to be small relative to plant-level impacts (Bock *et al.*, 2003).

For the most part, the magnitude of impacts noted above - especially impacts on fuel use and solid waste production - is directly proportional to the increased energy per kWh resulting from the reduction in plant efficiency, as indicated by Equation (6). Because CCS energy requirements are one to two orders of magnitude greater than for other power plant emission control technologies (such as particulate collectors and flue gas desulphurization systems), the illustrative results above emphasize the importance of maximizing overall plant efficiency while controlling environmental emissions.

3.6.1.4 *Resource and emission impacts of future systems*

The analysis above compared the impacts of CO_2 capture for a given plant type based on current technology. The magnitude of actual future impacts, however, will depend on four important factors: (1) the performance of technologies available at the time capture systems are deployed; (2) the type of power plants and capture systems actually put into service; (3) the total capacity of each plant type that is deployed; and, (4) the characteristics and capacity of plants they may be replacing.

Analyses of both current and near-future post-combustion, pre-combustion and oxy-fuel combustion capture technology options reveal that some of the advanced systems currently under development promise to significantly reduce the capture energy requirements - and associated impacts - while still reducing CO_2 emissions by 90% or more, as shown in Figure 3.19. Data in this figure was derived from the studies previously reported in Figures 3.6 and 3.7.

The timetable for deploying more efficient plants with CO_2 capture will be the key determinant of actual environmental changes. If a new plant with capture replaces an older, less efficient and higher-emitting plant currently in service, the net change in plant-level emission impacts and resource requirements would be much smaller than the values given earlier (which compared identical new plants with and without

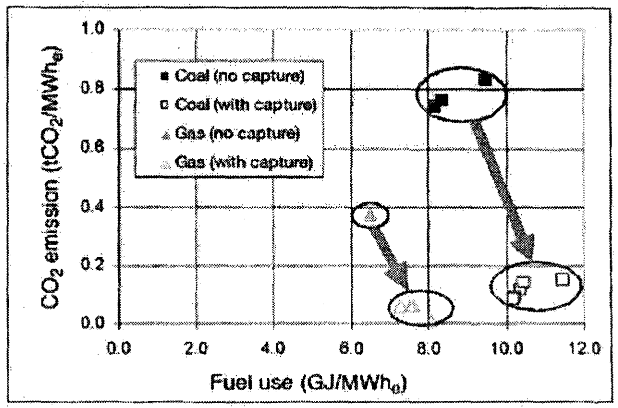

Figure 3.19 Fuel use for a reduction of CO_2 emissions from capture plants (data presented from design studies for power plants with and without capture shown in Figures 3.6 and 3.7).

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[2] Those additional energy requirements, if quantified, could be included by re-defining the system boundary and system efficiency terms in Equation (6) to apply to the full life cycle, rather than only the power plant. Such an analysis would require additional assumptions about the methods of fuel extraction, processing, transport to the power plant, and the associated energy requirements of those activities; as well as the CO_2 losses incurred during storage.

Table 3.5 Illustrative impacts of CCS energy requirements on plant-level resource consumption and non-CO_2 emission rates for three current power plant systems. Values shown are mass flow rates in kg per MWh for the capture plant, plus increases over the reference plant rates for the same plant type. See footnotes for additional details. (Source: Rubin *et al.*, 2005)

Capture Plant Parameter [a]	**PC** [b]		**IGCC** [c]		**NGCC** [d]	
	Rate	**Increase**	**Rate**	**Increase**	**Rate**	**Increase**
Resource consumption	**(All values in kg MWh^{-1})**					
Fuel	390	93	361	49	156	23
Limestone	27.5	6.8	-	-	-	-
Ammonia	0.80	0.19	-	-	-	-
CCS Reagents	2.76	2.76	0.005	0.005	0.80	0.80
Solid Wastes/byproduct						
Ash/slag	28.1	6.7	34.2	4.7	-	-
FGD residues	49.6	12.2	-	-	-	-
Sulfur	-	-	7.53	1.04	-	-
Spent CCS sorbent	4.05	4.05	0.005	0.005	0.94	0.94
Atmospheric emissions						
CO_2	107	*–704*	97	*-720*	43	*–342*
SO_x	0.001	*–0.29*	0.33	0.05	-	-
NO_x	0.77	0.18	0.10	0.01	0.11	0.02
NH_3	0.23	0.22	-	-	0.002	0.002

[a] Net power output of all plants is approximately 500 MW. Coal plants use Pittsburgh #8 coal with 2.1%S, 7.2% ash, 5.1% moisture and 303.2 MJ kg^{-1} lower heating value basis (LHV). Natural gas LHV = 59.9 MJ kg^{-1}. All plants capture 90% of potential CO_2 emissions and compress to 13.7 MPa.

[b] PC= Pulverized coal-fired plant; based on a supercritical unit with SCR, ESP and FGD systems, followed by an amine system for CO_2 capture. SCR system assumes 2 ppmv ammonia slip. SO_2 removal efficiency is 98% for reference plant and 99% for capture plant. Net plant efficiency (LHV basis) is 40.9% without CCS and 31.2% with CCS.

[c] IGCC=integrated gasification combined cycle system based on Texaco quench gasifiers (2 + 1 spare), two GE 7FA gas turbines, 3-pressure reheat HRSG. Sulfur removal efficiency is 98% via hydrolyzer plus Selexol system; Sulfur recovery via Claus plant and Beavon-Stretford tailgas unit. Net plant efficiency (LHV basis) is 39.1% without CCS and 33.8% with CCS.

[d] NGCC=natural gas combined cycle plant using two GE 7FA gas turbines and 3-pressure reheat HRSG, with an amine system for CO_2 capture. Net plant efficiency (LHV basis) is 55.8% without CCS and 47.6% with CCS.

capture). For example, the efficiency of a modern coal-based plant with capture is close to many older coal-burning plants currently in service. Replacing the latter with the former would thus reduce CO_2 emissions significantly with little or no net change in plant coal consumption or related solid waste impacts. In some cases, there could in fact be net reductions in other plant emissions, in support of clean air goals. If, however, the deployment of new CCS plants is delayed significantly, older existing plants could well be replaced by modern high-efficiency plants without capture. Such plants also would be built to provide additional capacity in regions with high electricity growth rates, such as in China and other parts of Asia today. A decade or two from now, the fleet of 'existing' plants in those regions would thus look very different from the present. Accordingly, the environmental and resource impacts of additional new plants with CO_2 capture would have to be assessed in the context of the future situation.

Because comparisons of different plant types require a specific context (or scenario) to be meaningful, this chapter has only focused on characterizing the effects of CO_2 capture systems relative to the same type of power plant and not the type of infrastructure it would replace (either currently, or in a future carbon-constrained world). If other systems such as the use of renewable energy, or electricity and synfuels cogenerated from coal, find significant applications, those systems too would require more comprehensive comparative life-cycle assessments of resource use and impacts that are not currently available. Chapter 8, however, assesses overall energy use impacts for illustrative scenarios of CCS deployment in competition with other carbon mitigation options.

3.6.2 *Issues related to the classification of carbon dioxide as a product*

As a current commercial product, carbon dioxide is subject to classification and regulations. The classification of carbon dioxide is dependent on its physical state (gas, liquid or solid), its concentration, impurities present and other criteria established by national legislative classification in different regions of the world. During the capture and concentration process, the quality properties can change the classification of the substance. A detailed assessment of carbon dioxide physical and chemical properties is provided in Annex I.

The environmental, monitoring, risk and legal aspects associated with carbon dioxide handling and storage are well established in the processing industry. However, much larger volumes are targeted for carbon dioxide processing for purposes of CCS than the volumes handled at present. On a local and regional level, additional emergency response and other regulatory measures can be expected in the future, depending on the rate of development of CCS. It is anticipated that human capacity will be developed to assess the monitoring, risk and legal aspects as required by the market.

At present, carbon dioxide typically occurs and is mainly traded as a non-flammable gas (US Department of Transportation classification class 2.2). The classification system of Transport Dangerous Goods, International Maritime Organization/International Maritime Dangerous Goods and International Civil Aviation Organization / International Air Transport Association, all classify carbon dioxide in class 2.2, non-flammable, non-corrosive and non-poisonous gases. In US federal regulations, carbon dioxide is not listed as a product in the Clean Water Act (CWA 307 and 311), Clean Air Act (CAA 112) or the Toxics Release Inventory. In other international regulations carbon dioxide is not classified in the European Inventory of Existing Commercial Chemical Substance or other international lists, but in Canada is classified as a compressed gas (class A) on the Canadian Energy Pipeline Association Dangerous Substances List (Hazardous Substances Data Bank, 2002).

3.6.3 *Health and safety risks associated with carbon dioxide processing*

The effects of exposure to carbon dioxide are described in Annex I. However, a risk assessment that includes an understanding of both exposure and effects is required to characterize the risk for various situations associated with carbon dioxide processing (European Chemicals Bureau, 2003); see the following two sections for established risk management practices. The most probable routes of human exposure to carbon dioxide are inhalation or skin contact. The need for a risk-based approach is clear from the following two descriptions. Carbon dioxide and its products of degradation are not legally classified as a toxic substance; is non-hazardous on inhalation, is a non-irritant and does not sensitize or permeate the skin. However, chronic effects on humans follow from long-term exposure to airborne carbon dioxide concentrations of between 0.5 and 1% resulting in metabolic acidosis and increased calcium deposits in soft tissues. The substance is toxic to the cardiovascular system and upper respiratory tract at concentrations above 3%. Sensitive populations to elevated carbon dioxide levels are described in Annex I. The product risk assessment process is therefore necessary as with any other chemical use to determine the risk and establish the necessary risk management processes.

As an asphyxiate carbon dioxide presents the greatest danger. If atmospheric oxygen is displaced such that oxygen concentration is 15-16%, signs of asphyxia will be noted. Skin contact with dry ice has caused serious frostbites and blisters (Hazardous Substances Data Bank, 2002). Protective equipment and clothing required in the processing industries include full face-piece respirators to prevent eye contact and appropriate personal protective clothing to protect the skin from becoming frozen by the liquid.

3.6.4 *Plant design principles and guidelines used by governments, industries and financiers*

New plant facilities like those envisioned for carbon dioxide are subject to design guidelines for the petrochemical industry as determined by relevant authorities. One example is the European Unions' Integrated Pollution Prevention and Control (IPPC) directive requiring the application of the principles of Best Available Technology Not Entailing Excessive Cost (BATNEEC). Carbon dioxide capture and compression processes are listed in several guidelines as gas-processing facilities. Typically the World Bank guidelines and other financial institutions have specific requirements to reduce risk and these require monitoring (World Bank, 1999) which is part of routine plant monitoring to detect accidental releases. Investor guidelines like the World Bank guidelines are particularly important for developing countries where there is less emphasis on monitoring and legislation. National and regional legislation for plant design and specifications from organizations like the US Environmental Protection Agency are available to guide the development of technology.

3.6.5 Commissioning, good practice during operations and sound management of chemicals

The routine engineering design, commissioning and start-up activities associated with petrochemical facilities are applicable to the capture and compression of carbon dioxide; for example Hazard Operability studies are conducted on a routine basis for new facilities (Sikdar and Diwekar, 1999).

The management of carbon dioxide and reagents inside factory battery limits will be in accordance with the relevant practices in use for carbon dioxide. For carbon dioxide, US Occupational Health and Safety Act standards and National Institute for Occupational Safety and Health recommendations exist, which are applied widely in industry to guide safe handling of carbon dioxide and the same applies to reagents and catalysts used. Well established and externally audited management systems such as International Standards Organization's ISO 14001 (environment) and ISO 9001 (quality) and Occupational Health and Safety (OHSAS 18000) exist to provide assurance that environment, safety, health and quality management systems are in place (American Institute of Chemical Engineers, 1995). Tools like life-cycle assessment (ISO 14040 series) with the necessary boundary expansion methodology are useful to determine the overall issues associated with a facility and assist with selection of parameters such as energy carriers, operational conditions and materials used in the process. The life-cycle assessment will also indicate if a trouble-free capture system does generate environmental concerns elsewhere in the product life cycle.

3.6.6 Site closure and remediation

It is not anticipated that carbon dioxide capture will result in a legacy of polluted sites requiring remediation after plant closure, assuming that standard operating procedures and management practices in the previous section are followed. However, depending on the technology used and the materials procured for operations, waste disposal at the facilities and operation according to a formal management system from construction, operation to the development of site closure plans will largely assist to reduce the risk of a polluted site after closure of operations.

3.7 Cost of CO_2 capture

This section of the report deals with the critical issue of CO_2 capture costs. We begin with an overview of the many factors that affect costs and the ability to compare published estimates on a consistent basis. Different measures of CO_2 capture cost also are presented and discussed. The literature on CO_2 capture costs for currently available technologies is then reviewed, along with the outlook for future costs over the next several decades.

3.7.1 Factors affecting CO_2 capture cost

Published estimates for CO_2 capture costs vary widely, mainly as a result of different assumptions regarding technical factors related to plant design and operation (e.g., plant size, net efficiency, fuel properties and load factor), as well as key economic and financial factors such as fuel cost, interest rates and plant lifetime. A number of recent papers have addressed this issue and identified the principal sources of cost differences and variability (Herzog, 1999; Simbeck, 1999; Rubin and Rao, 2003). This section draws heavily on Rubin and Rao (2003) to highlight the major factors affecting the cost of CO_2 capture.

3.7.1.1 Defining the technology of interest

Costs will vary with the choice of CO_2 capture technology and the choice of power system or industrial process that generates the CO_2 emissions. In engineering-economic studies of a single plant or CO_2 capture technology, such definitions are usually clear. However, where larger systems are being analyzed, such as in regional, national or global studies of CO_2 mitigation options, the specific technologies assumed for CO_2 production and capture may be unclear or unspecified. In such cases, the context for reported cost results also may be unclear.

3.7.1.2 Defining the system boundary

Any economic assessment should clearly define the 'system' whose CO_2 emissions and cost is being characterized. The most common assumption in studies of CO_2 capture is a single facility (most often a power plant) that captures CO_2 and transports it to an off-site storage area such as a geologic formation. The CO_2 emissions considered are those released at the facility before and after capture. Reported costs may or may not include CO_2 transport and storage costs. *The system boundary of interest in this section of the report includes only the power plant or other process of interest and does not include CO_2 transport and storage systems, whose costs are presented in later chapters. CO_2 compression, however, is assumed to occur within the facility boundary and therefore the cost of compression is included in the cost of capture.*[3]

In some studies the system boundary includes emissions of

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[3] Alternatively, compression costs could be attributed wholly or in part to CO_2 transport and storage. Most studies, however, include compression with capture cost. This also facilitates comparisons of capture technologies that operate at different pressures, and thus incur different costs to achieve a specified final pressure.

CO_2 and other greenhouse gases such as methane (expressed as equivalent CO_2) over the complete fuel cycle encompassing not only the power plant or facility in question, but also the 'upstream' processes of extraction, refining and transport of fuel used at the facility, plus any 'downstream' emissions from the use or storage of captured CO_2. Still larger system boundaries might include all power plants in a utility company's system; all plants in a regional or national grid; or a national economy where power plant and industrial emissions are but one element of the overall energy system being modelled. In each of these cases it is possible to derive a mitigation cost for CO_2, but the results are not directly comparable because they reflect different system boundaries and considerations. Chapter 8 discusses such differences in more detail and presents results for alternative systems of interest.

3.7.1.3 *Defining the technology time frame and maturity*

Another factor that is often unclear in economic evaluations of CO_2 capture is the assumed time frame and/or level of maturity for the technology under study. Does the cost estimate apply to a facility that would be built today, or at some future time? This is especially problematic in studies of 'advanced' technologies that are still under development and not currently commercial. In most cases, studies of advanced technologies assume that costs apply to an 'nth plant' to be built sometime in the future when the technology is mature. Such estimates reflect the expected benefits of technological learning, but may or may not adequately account for the increased costs that typically occur in the early stages of commercialization. The choice of technology time frame and assumed rate of cost improvements and can therefore make a big difference in CO_2 capture cost estimates.

3.7.1.4 *Different cost measures and assumptions*

The literature reveals a number of different measures used to characterize CO_2 capture and storage costs, including capital cost, cost of electricity, cost of CO_2 avoided and others. Because some of these measures are reported in the same units (e.g., US dollars per tonne of CO_2) there is great potential for misunderstanding. Furthermore, for any given cost measure, different assumptions about the technical, economic and financial parameters used in cost calculations can also give rise to large differences in reported capture costs. Section 3.7.2 elaborates on some of the common metrics of cost and the parameters they employ.

3.7.2 Measures of CO_2 capture cost

We define four common measures of CO_2 capture cost here: capital cost, incremental product cost (such as the cost of electricity), cost of CO_2 avoided and cost of CO_2 captured or removed. Each of these measures provides a different perspective on CO_2 capture cost for a particular technology or system of interest. All of them, however, represent an 'engineering economic' perspective showing the added cost of capturing CO_2 in a particular application. Such measures are required to address larger questions such as which options or strategies to pursue - a topic addressed later in Chapter 8.

3.7.2.1 *Capital cost*

Capital cost (also known as investment cost or first cost) is a widely used, albeit incomplete, metric of the cost of a technology. It is often reported on a normalized basis (e.g., cost per kW). For CO_2 capture systems, the capital cost is generally assumed to represent the total expenditure required to design, purchase and install the system of interest. It may also include the additional costs of other plant components not needed in the absence of a CO_2 capture device, such as the costs of an upstream gas purification system to protect the capture device. Such costs often arise in complex facilities like a power plant. Thus, the total incremental cost of CO_2 capture for a given plant design is best determined as the difference in total cost between plants with and without CO_2 capture, producing the same amounts of useful (primary) product, such as electricity.

Different organizations employ different systems of accounts to specify the elements of a capital cost estimate. For electric power plants, one widely used procedure is that defined by the Electric Power Research Institute (EPRI, 1993). However, because there is no universally employed nomenclature or system of accounts, capital costs reported by different organizations or authors may not always include the same items. The terms used to report capital costs may further disguise such differences and lead to misunderstandings about what is and is not included. For example, power plant cost studies often report a value of capital cost that does not include the cost of interest during construction or other so-called 'owners costs' that typically add at least 10-20% (sometimes substantially more) to the 'total capital requirement' of a system. Only if a capital cost breakdown is reported can such omissions be discovered. Studies that fail to report the year of a cost estimate introduce further uncertainty that may affect cost comparisons.

3.7.2.2 *Incremental product cost*

The effect of CO_2 capture on the cost of electricity (or other product) is one of the most important measures of economic impact. Electric power plants, a major source of CO_2 emissions, are of particular interest in this regard. The cost electricity (COE) for a power plant can be calculated as:[4]

$$\mathrm{COE} = [(\mathrm{TCR})(\mathrm{FCF}) + (\mathrm{FOM})]/[(\mathrm{CF})(8760)(\mathrm{kW})] + \mathrm{VOM} + (\mathrm{HR})(\mathrm{FC}) \qquad (7)$$

where, COE = levelized cost of electricity (US\$ kWh^{-1}), TCR = total capital requirement (US\$), FCF = fixed charge factor (fraction yr^{-1}), FOM = fixed operating costs (US\$ yr^{-1}), VOM = variable operating costs (US\$ kWh^{-1}), HR = net plant heat rate (kJ kWh^{-1}), FC = unit fuel cost (US\$ kJ^{-1}), CF = capacity

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[4] For simplicity, the value of FCF in Equation (7) is applied to the total capital requirement. More detailed calculations of COE based on a year-by-year analysis apply the FCF to the total capital cost excluding owner's costs (such as interest during construction), which are separately accounted for in the years prior to plant start-up.

factor (fraction), 8760 = total hours in a typical year and kW = net plant power (kW). In this chapter, the costs in Equation (7) include only the power plant and capture technologies and not the additional costs of CO_2 transport and storage that are required for a complete system with CCS. The incremental COE is the difference in electricity cost with and without CO_2 capture.[5] Again, the values reported here exclude transport and storage costs. Full CCS costs are reported in Chapter 8.

Equation (7) shows that many factors affect this incremental cost. For example, just as the total capital cost includes many different items, so too do the fixed and variable costs associated with plant operation and maintenance (O&M). Similarly, the fixed charge factor (FCF, also known as the capital recovery factor) reflects assumptions about the plant lifetime and the effective interest rate (or discount rate) used to amortize capital costs.[6] Assumptions about any of the factors in Equation (7) can have a pronounced effect on overall cost results. Nor are these factors all independent of one another. For example, the design heat rate of a new power plant may affect the total capital requirement since high-efficiency plants usually are more costly than lower-efficiency designs.

Finally, because several of the parameter values in Equation (7) may change over the operating life of a facility (such as the capacity factor, unit fuel cost, or variable operating costs), the value of COE also may vary from year to year. To include such effects, an economic evaluation would calculate the net present value (NPV) of discounted costs based on a schedule of year-to-year cost variations, in lieu of the simpler formulation of Equation (7). However, most engineering-economic studies use Equation (7) to calculate a single value of 'levelized' COE over the assumed life of the plant. The levelized COE is the cost of electricity, which, if sustained over the operating life of the plant, would produce the same NPV as an assumed stream of variable year-to-year costs. In most economic studies of CO_2 capture, however, all parameter values in Equation (7) are held constant, reflecting (either implicitly or explicitly) a levelized COE over the life of the plant.[7]

3.7.2.3 Cost of CO_2 avoided

One of the most widely used measures for the cost of CO_2 capture and storage is the 'cost of CO_2 avoided.' This value reflects the average cost of reducing atmospheric CO_2 mass emissions by one unit while providing the same amount of useful product as a 'reference plant' without CCS. For an electric power plant the avoidance cost can be defined as:

$$\text{Cost of } CO_2 \text{ avoided (US\$/t}CO_2\text{)} =$$

$$[(\text{COE})_{\text{capture}} - (\text{COE})_{\text{ref}}] \,/\, [(CO_2\ \text{kWh}^{-1})_{\text{ref}} - (CO_2\ \text{kWh}^{-1})_{\text{capture}}] \qquad (8)$$

where, COE = levelized cost of electricity (US$ kWh^{-1}) as given by Equation (7) and CO_2 kWh^{-1} = CO_2 mass emission rate (in tonnes) per kWh generated, based on the net plant capacity for each case. The subscripts 'capture' and 'ref' refer to the plant with and without CO_2 capture, respectively. Note that while this equation is commonly used to report a cost of CO_2 avoided for the capture portion of a full CCS system, strictly speaking it should be applied only to a complete CCS system including transport and storage costs (since all elements are required to avoid emissions to the atmosphere).

The choice of the reference plant without CO_2 capture plays a key role in determining the CO_2 avoidance cost. *Here the reference plant is assumed to be a plant of the same type and design as the plant with CO_2 capture.* This provides a consistent basis for reporting the incremental cost of CO_2 capture for a particular type of facility.

Using Equation (8), a cost of CO_2 avoided can be calculated for any two plant types, or any two aggregates of plants. Thus, special care should be taken to ensure that the basis for a reported cost of CO_2 avoided is clearly understood or conveyed. For example, the avoidance cost is sometimes taken as a measure of the cost to society of reducing GHG emissions.[8] In that case, the cost per tonne of CO_2 avoided reflects the average cost of moving from one situation (e.g., the current mix of power generation fuels and technologies) to a different mix of technologies having lower overall emissions. Alternatively, some studies compare individual plants with and without capture (as we do), but assume different types of plants for the two cases. Such studies, for example, might compare a coal-fired plant with capture to an NGCC reference plant without capture. Such cases reflect a different choice of system boundaries and address very different questions, than those addressed here. However, the data presented in this section (comparing the same type of plant with and without capture) can be used to estimate a cost of CO_2 avoided for any two of the systems of interest in a particular situation (see Chapter 8).

3.7.2.4 Cost of CO_2 captured or removed

Another cost measure frequently reported in the literature is based on the mass of CO_2 captured (or removed) rather than emissions avoided. For an electric power plant it can be defined as:

$$\text{Cost of } CO_2 \text{ Captured (US\$/t}CO_2\text{)} = [(\text{COE})_{\text{capture}} - (\text{COE})_{\text{ref}}] \,/\, (CO_{2,\,\text{captured}}\ \text{kWh}^{-1}) \qquad (9)$$

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[5] For CO_2 capture systems with large auxiliary energy requirements, the magnitude of incremental cost also depends on whether the plant with capture is assumed to be a larger facility producing the same net output as the reference plant without capture, or whether the reference plant is simply derated to supply the auxiliary energy. While the latter assumption is most common, the former yields a smaller incremental cost due to economy-of-scale effects.

[6] In its simplest form, FCF can be calculated from the project lifetime, n (years), and annual interest rate, i (fraction), by the equation: $\text{FCF} = i \,/\, [1 - (1 + i)^{-n}]$.

[7] Readers not familiar with these economic concepts and calculations may wish to consult a basic economics text, or references such as (EPRI, 1993) or (Rubin, 2001) for more details.

[8] As used here, 'cost' refers only to money spent for technology, fuels and related materials, and not to broader societal measures such as macroeconomic costs or societal damage costs associated with atmospheric emissions. Further discussions and use of the term 'cost of CO_2 avoided' appear in Chapter 8 and in the references cited earlier.

where, $CO_{2,\ captured}$ kWh^{-1} = total mass of CO_2 captured (in tonnes) per net kWh for the plant with capture. This measure reflects the economic viability of a CO_2 capture system given a market price for CO_2 (as an industrial commodity). If the CO_2 captured at a power plant can be sold at this price (e.g., to the food industry, or for enhanced oil recovery), the COE for the plant with capture would be the same as for the reference plant having higher CO_2 emissions. Numerically, the cost of CO_2 captured is lower than the cost of CO_2 avoided because the energy required to operate the CO_2 capture systems increases the amount of CO_2 emitted per unit of product.

3.7.2.5 *Importance of CCS energy requirements*

As the energy requirement for CCS is substantially larger than for other emission control systems, it has important implications for plant economics as well as for resource requirements and environmental impacts. The energy 'penalty' (as it is often called) enters cost calculations in one of two ways. Most commonly, all energy needed to operate CCS absorbers, compressors, pumps and other equipment is assumed to be provided within the plant boundary, thus lowering the net plant capacity (kW) and output (kWh, in the case of a power plant). The result, as shown by Equation (7), is a higher unit capital cost (US\$ kW^{-1}) and a higher cost of electricity production (US\$ kWh^{-1}). Effectively, these higher unit costs reflect the expense of building and operating the incremental capacity needed to operate the CCS system.

Alternatively, some studies - particularly for industrial processes such as hydrogen production - assume that some or all of the energy needed to operate the CCS system is purchased from outside the plant boundary at some assumed price. Still other studies assume that new equipment is installed to generate auxiliary energy on-site. In these cases, the net plant capacity and output may or may not change and may even increase. However, the COE in Equation (7) again will rise due to the increases in VOM costs (for purchased energy) and (if applicable) capital costs for additional equipment. The assumption of purchased power, however, does not guarantee a full accounting of the replacement costs or CO_2 emissions associated with CCS. In all cases, however, the larger the CCS energy requirement, the greater the difference between the costs of CO_2 captured and avoided.

3.7.2.6 *Other measures of cost*

The cost measures above characterize the expense of adding CO_2 capture to a single plant of a given type and operating profile. A broader modelling framework is needed to address questions involving multiple plants (e.g., a utility system, regional grid, or national network), or decisions about what type of plant to build (and when). Macroeconomic models that include emission control costs as elements of a more complex framework typically yield cost measures such as the change in gross domestic product (GDP) from the imposition of a carbon constraint, along with changes in the average cost of electricity and cost per tonne of CO_2 abated. Such measures are often useful for policy analysis, but reflect many additional assumptions about the structure of an economy as well as the cost of technology. Chapter 8 provides a discussion of macroeconomic modelling as it relates to CO_2 capture costs.

3.7.3 *The context for current cost estimates*

Recall that CO_2 capture, while practiced today in some industrial applications, is not currently a commercial technology used at large electric power plants, which are the focus of most CCS studies. Thus, cost estimates for CO_2 capture systems rely mainly on studies of hypothetical plants. Published studies also differ significantly in the assumptions used for cost estimation. Equation (7), for example, shows that the plant capacity factor has a major impact on the cost of electric power generation, as do the plant lifetime and discount rate used to compute the fixed charge factor. The COE, in turn, is a key element of CO_2 avoidance cost, Equation (8). Thus, a high plant capacity factor or a low fixed charge rate will lower the cost of CO_2 capture per kWh. The choice of other important parameters, such as the plant size, efficiency, fuel type and CO_2 removal rate will similarly affect the CO_2 capture cost. Less apparent, but often equally important, are assumptions about parameters such as the 'contingency cost factors' embedded in capital cost estimates to account for unspecified costs anticipated for technologies at an early stage of development, or for commercial systems that have not yet been demonstrated for the application, location, or plant scale under study.

Because of the variability of assumptions employed in different studies of CO_2 capture, a systematic comparison of cost results is not straightforward (or even possible in most cases). Moreover, there is no universally 'correct' set of assumptions that apply to all the parameters affecting CO_2 capture cost. For example, the quality and cost of natural gas or coal delivered to power plants in Europe and the United States may differ markedly. Similarly, the cost of capital for a municipal or government-owned utility may be significantly lower than for a privately-owned utility operating in a competitive market. These and other factors lead to real differences in CO_2 capture costs for a given technology or power generation system. Thus, we seek in this report to elucidate the key assumptions employed in different studies of similar systems and technologies and their resulting impact on the cost of CO_2 capture. Analyses comparing the costs of alternative systems on an internally consistent basis (within a particular study) also are highlighted. Nor are all studies equally credible, considering their vintage, data sources, level of detail and extent of peer review. Thus, the approach adopted here is to rely as much as possible on recent peer-reviewed literature, together with other publicly-available studies by governmental and private organizations heavily involved in the field of CO_2 capture. Later, in Chapter 8, the range of capture costs reported here are combined with cost estimates for CO_2 transport and storage to arrive at estimates of the overall cost of CCS for selected power systems and industrial processes.

Table 3.6 Confidence levels for technology and system cost estimates.

Confidence Level	Description
Very High	Mature technology with multiple commercial replications for this application and scale of operation; considerable operating experience and data under a variety of conditions.
High	Commercially deployed in applications similar to the system under study, but at a smaller scale and/or with limited operating experience; no major problems or issues anticipated in this application; commercial guarantees available.
Moderate	No commercial application for the system and/or scale of interest, but technology is commercially deployed in other applications; issues of scale-up, operability and reliability remain to be demonstrated for this application.
Low	Experience and data based on pilot plant or proof-of-concept scale; no commercial applications or full-scale demonstrations; significant technical issues or cost-related questions still to be resolved for this application.
Very Low	A new concept or process not yet tested, or with operational data limited to the laboratory or bench-scale level; issues of large-scale operability, effectiveness, reliability and manufacturability remain to be demonstrated.

3.7.4 Overview of technologies and systems evaluated

Economic studies of CO_2 capture have focused mainly on electric power generation, a major source of CO_2 emissions. To a lesser extent, CO_2 capture from industrial processes also has been subject to economic evaluations, especially processes producing hydrogen, often in combination with other products.

The sections below review and summarize recent estimates of CO_2 capture costs for major systems of interest. Sections 3.7.5 to 3.7.8 focus first on the cost of current CO_2 capture technologies, while Sections 3.7.10 to 3.7.12 go on to discuss improved or 'advanced' technologies promising lower costs in the future. In all cases the system boundary is defined as a single facility at which CO_2 is captured and compressed for delivery to a transport and storage system. To reflect different levels of confidence (or uncertainty) in cost estimates for technologies at different stages of development, the qualitative descriptors shown in Table 3.6 are applied in summarizing published cost estimates.[9] The studies reviewed typically report costs in US dollars for reference years ranging from 2000 to early 2004. Because inflation effects generally have been small during this period no adjustments have been made in summarizing ranges of reported costs.

3.7.5 Post-combustion CO_2 capture cost for electric power plants (current technology)

Most of the world's electricity is currently generated from the combustion of fossil fuels, especially coal and (to an increasing extent) natural gas. Hence, the ability to capture and store the CO_2 emitted by such plants has been a major focus of investigation. This section of the report focuses on the cost of currently available technology for CO_2 capture. Because of the relatively low CO_2 concentration in power plant flue gases, chemical absorption systems have been the dominant technology of interest for post-combustion capture (see Section 3.3.2). However, the cost of CO_2 capture depends not only on the choice of capture technology, but also - and often more importantly - on the characteristics and design of the overall power plant. For purposes of cost reporting, we distinguish between coal-fired and gas-fired plant designs and between new and existing facilities.

3.7.5.1 New coal-fired power plants

Table 3.7 summarizes the key assumptions and results of recent studies of post-combustion CO_2 capture at new coal-fired power plants. Assumed plant sizes with CO_2 capture range from approximately 300-700 MW net power output. In all cases, CO_2 capture is accomplished using an amine-based absorption system, typically MEA. Capture efficiencies range from 85-95% with the most common value being 90%. The studies employ different assumptions about other key parameters such as the base power plant efficiency, coal properties, coal cost, plant capacity factor, CO_2 product pressure and financial parameters such as the fixed charge factor. All of these factors have a direct influence on total plant cost and the cost of CO_2 capture.

Table 3.7 summarizes several measures of CO_2 capture cost, both in absolute and relative terms. Across the full set of studies, CO_2 capture adds 44-87% to the capital cost of the reference plant (US\$ kW^{-1}) and 42-81% to the cost of electricity (US\$ MWh^{-1}), while achieving CO_2 reductions of approximately 80-90% per net kWh produced. The cost of CO_2 avoided for these cases varies from 29-51 US\$/tCO_2. The absolute values of capital cost, COE and incremental cost of electricity in Table 3.7 reflect the different assumptions employed in each study. The result is an incremental COE of 18-38 US\$ MWh^{-1} (or US\$ 0.018-0.038 kWh^{-1}) for CO_2 capture. The total COE for plants with capture ranges from 62-87 US\$ MWh^{-1}. In all cases, a significant portion of the total CO_2 capture cost is due to the energy requirement for CO_2 capture and compression. For the studies in Table 3.7, the plants with CO_2 capture require 24-42% more fuel input per MWh of plant output relative to a similar reference plant without capture. Roughly half the energy is required for solvent regeneration and a third for CO_2 compression.

While many factors contribute to the cost differences observed in Table 3.7, systematic studies of the influence of different factors indicate that the most important sources of variability in reported cost results are assumptions about the

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[9] These descriptions are used in subsequent tables to characterize systems with CO_2 capture. In most cases the cost estimates for reference plants (without capture) would rank as high (e.g., IGCC power plants) or very high (e.g., PC and NGCC power plants).

Table 3.7 CO_2 capture costs: new pulverized-coal power plants using current technology.

Study Assumptions and Results	**Parsons**	**Parsons**	**Simbeck**	**IEA GHG**	**IEA GHG**	**Rubin *et al.***	**Range**		**NETL**	**Rao & Rubin**	**Stobbs & Clark**
	2002b	**2002b**	**2002**	**2004**	**2004**	**2005**	**min**	**max**	**2002**	**2002**	**2005**
	SUPERCRITICAL UNITS / BITUMINOUS COALS								**SUBCRIT UNITS / LOW RANK COALS**		
Reference Plant (without capture)			*			*			*	*	
Boiler type (subcritical, super, ultra)	super	ultra	ultra	ultra	ultra	super			subcritical	subcritical	super
Coal type (bit, sub-bit, lig) and %S	bit, 2.5% S	bit, 2.5% S	bit, 1% S	bit, 1% S	bit, 1% S	bit, 2.1% S			bit, 2.5%S	sub-bit, 0.5%S	lignite
Emission control technologies (SO_x/NO_x)	FGD, SCR	FGD, SCR	FGD, SCR	FGD, SCR	FGD, SCR	FGD, SCR			FGD	FGD, SCR	FGD, SCR, LoTOx
Reference plant net output (MW)	462	506	520	758	754	524	**462**	**758**	397	462	424
Plant capacity factor (%)	65	65	80	85	85	75	**65**	**85**	85	75	90
Net plant efficiency, LHV (%)	42.2	44.8	44.5	44.0	43.7	40.9	**41**	**45**	38.9	36.1	43.4
Coal cost, LHV (US$ GJ^{-1})	1.29		0.98	1.50	1.50	1.25	**0.98**	**1.50**	1.03	1.25	0.88
Reference plant emission rate (t CO_2 MWh^{-1})	0.774	0.736	0.76	0.743	0.747	0.811	**0.74**	**0.81**	0.835	0.941	0.883
Capture Plant Design											
CO_2 capture technology	MEA	MEA	MEA	MEA	KS-1	MEA			MEA	MEA	MEA
Net plant output with capture (MW)	329	367	408	666	676	492	**329**	**676**	283	326	311.0
Net plant efficiency, LHV (%)	30.1	32.5	34.9	34.8	35.4	31.1	**30**	**35**	27.7	25.4	31.8
CO_2 capture system efficiency (%)	90	90	85	87.5	90	90	**85**	**90**	95	90	95
CO_2 emission rate after capture (t MWh^{-1})	0.108	0.101	0.145	0.117	0.092	0.107	**0.09**	**0.15**	0.059	0.133	0.060
CO_2 captured (Mt yr^{-1})	1.830	2.350	2.360	4.061	4.168	3.102	**1.83**	**4.17**	2.346	2.580	2.795
CO_2 product pressure (MPa)	8.4	8.4	13.7	11.0	11.0	13.9	**8**	**14**	10.3	13.9	13.9
CCS energy requirement (% more input MWh^{-1})	40	38	28	26	24	31	**24**	**40**	40	42	36
CO_2 reduction per kWh (%)	**86**	**86**	**81**	**84**	**88**	**87**	**81**	**88**	**93**	**86**	**93**
Cost Results			***	**	**						***
Cost year basis (constant dollars)	2000	2000	2000	2004	2004	2002			2002	2000	2003
Fixed charge factor (%)	15.5	15.5	12.7	11.0	11.0	14.8	**11.0**	**15.5**	14.8	15.0	
Reference plant TCR (US$ kW^{-1})	1281	1161	1486	1319	1265	1205	**1161**	**1486**	1268	1236	1891
Capture plant TCR (US$ kW^{-1})	2219	1943	2578	1894	2007	1936	**1894**	**2578**	2373	2163	3252
Incremental TCR for capture (US$ kW^{-1})	938	782	1092	575	742	731	**575**	**1092**	1105	927	1361
Reference plant COE (US$ MWh^{1})	**51.5**	**51.0**	**42.9**	**43.9**	**42.8**	**46.1**	**43**	**52**	**42.3**	**49.2**	**44.5**
Capture plant COE (US$ MWh^{1})	**85.6**	**82.4**	**70.9**	**62.4**	**63.0**	**74.1**	**62**	**86**	**76.6**	**87.0**	**74.3**
Incremental COE for capture (US$ MWh^{1})	**34.1**	**31.4**	**28**	**18.5**	**20.2**	**28**	**18**	**34**	**37.8**	**37.8**	**29.8**
% increase in capital cost (over ref. plant)	73	67	74	44	59	61	**44**	**74**	87	75	72
% increase in COE (over ref. plant)	**66**	**62**	**65**	**42**	**47**	**61**	**42**	**66**	**81**	**77**	**67**
Cost of CO_2 captured (US$/t$CO_2$)	35	28	34	23	24	29	**23**	**35**	31	31	26
Cost of CO_2 avoided (US$/t$CO_2$)	51	49	43	29	31	40	**29**	**51**	43	47	36
Capture cost confidence level (see Table 3.6)	moderate								-	moderate	

Notes: All costs in this table are for capture only and do not include the costs of CO_2 transport and storage; see Chapter 8 for total CCS costs. * Reported HHV values converted to LHV assuming LHV/HHV = 0.96 for coal. ** Reported capital costs increased by 8% to include interest during construction. ***Reported capital costs increased by 15% to estimate interest during construction and other owners' costs.

CO_2 capture system energy requirement, power plant efficiency, fuel type, plant capacity factor and fixed charge rate (Rao and Rubin, 2002). In this regard, it is useful to note that the lowest-cost capture systems in Table 3.7 (in terms of COE and cost of CO_2 avoided) come from a recent study (IEA GHG, 2004) that combines an efficient supercritical power plant design using bituminous coal, with high plant utilization, lowest fixed charge rate and more energy-efficient amine system designs, as recently announced by two major vendors (but not yet demonstrated on coal-fired power plants). In contrast, the highest reported COE values are for less efficient subcritical plant designs using low rank coal, combined with lower capacity factors, higher fixed charge rates and employing amine system designs typical of units currently in operation at small power plants.

Recent increases in world coal prices, if sustained, also would affect the levelized COE values reported here. Based on one recent study (IEA GHG, 2004), each 1.00 US\$ GJ^{-1} increase in coal price would increase the COE by 8.2 US\$ MWh^{-1} for a new PC plant without capture and by 10.1 US\$ MWh^{-1} for a plant with capture.

These results indicate that new power plants equipped with CO_2 capture are likely to be high-efficiency supercritical units, which yield lowest overall costs. The worldwide use of supercritical units (without capture) with current usage at 155 GW_e (Section 3.1.2.2), is rapidly increasing in several regions of the world and, as seen in Table 3.7, the preponderance of recent studies of CO_2 capture are based on supercritical units using bituminous coals. For these plants, Table 3.7 shows that capture systems increase the capital cost by 44-74% and the COE by 42-66% (18-34 US\$ MWh^{-1}). The major factors contributing to these ranges were differences in plant size, capacity factor and fixed charge factor. New or improved capture systems and power plant designs that promise to further reduce the costs of CO_2 capture are discussed later in Section 3.7.7. First, however, we examine CO_2 capture costs at existing plants.

3.7.5.2 Existing coal-fired plants

Compared to the study of new plants, CO_2 capture options for existing power plants have received relatively little study to date. Table 3.8 summarizes the assumptions and results of several studies estimating the cost of retrofitting an amine-based CO_2 capture system to an existing coal-fired power plant. Several factors significantly affect the economics of retrofits, especially the age, smaller sizes and lower efficiencies typical of existing plants relative to new builds. The energy requirement for CO_2 capture also is usually higher because of less efficient heat integration for sorbent regeneration. All of these factors lead to higher overall costs. Existing plants not yet equipped with a flue gas desulphurization (FGD) system for SO_2 control also must be retrofitted or upgraded for high-efficiency sulphur capture in addition to the CO_2 capture device. For plants with high NO_x levels, a NO_2 removal system also may be required to minimize solvent loss from reactions with acid gases. Finally, site-specific difficulties, such as land availability, access to plant areas and the need for special ductwork, tend to further increase the capital cost of any retrofit project relative to an equivalent new plant installation. Nonetheless, in cases where the capital cost of the existing plant has been fully or substantially amortized, Table 3.8 shows that the COE of a retrofitted plant with capture (including all new capital requirements) can be comparable to or lower than that of a new plant, although the incremental COE is typically higher because of the factors noted above.

Table 3.8 further shows that for comparable levels of about 85% CO_2 reduction per kWh, the average cost of CO_2 avoided for retrofits is about 35% higher than for the new plants analyzed in Table 3.7. The incremental capital cost and COE depend strongly on site-specific assumptions, including the degree of amortization and options for providing process energy needs. As with new plants, heat and power for CO_2 capture are usually assumed to be provided by the base (reference) plant, resulting in a sizeable (30 to 40%) plant output reduction. Other studies assume that an auxiliary gas-fired boiler is constructed to provide the CO_2 capture steam requirements and (in some cases) additional power. Low natural gas prices can make this option more attractive than plant output reduction (based on COE), but such systems yield lower CO_2 reductions (around 60%) since the emissions from natural gas combustion are typically not captured. For this reason, the avoided cost values for this option are not directly comparable to those with higher CO_2 reductions.

Also reflected in Table 3.8 is the option of rebuilding an existing boiler and steam turbine as a supercritical unit to gain efficiency improvements in conjunction with CO_2 capture. One recent study (Gibbins *et al.*, 2005) suggests this option could be economically attractive in conjunction with CO_2 capture since the more efficient unit minimizes the cost of capture and yields a greater net power output and a lower COE compared to a simple retrofit. The use of a new and less energy-intensive capture unit yields further cost reductions in this study. Another recent study similarly concluded that the most economical approach to CO_2 capture for an existing coal-fired plant was to combine CO_2 capture with repowering the unit with an ultra-supercritical steam system (Simbeck, 2004). One additional option, repowering an existing unit with a coal gasifier, is discussed later in Section 3.7.6.2.

3.7.5.3 Natural gas-fired power plants

Power plants fuelled by natural gas may include gas-fired boilers, simple-cycle gas turbines, or natural gas combined cycle (NGCC) units. The current operating capacity in use globally is 333 GW_e for gas-fired boilers, 214 GW_e for simple cycle gas turbines and 339 GW_e for NGCC (IEA WEO, 2004). The absence of sulphur and other impurities in natural gas reduces the capital costs associated with auxiliary flue gas clean-up systems required for amine-based CO_2 capture technology. On the other hand, the lower concentration of CO_2 in gas-fired units tends to increase the cost per tonne of CO_2 captured or avoided relative to coal-fired units.

Table 3.9 summarizes the assumptions and cost results of several recent studies of CO_2 capture at gas-fired combined cycle power plants ranging in size from approximately 300-700 MW. Relative to reference plants without capture, to achieve net

Table 3.8 CO$_2$ capture costs: existing pulverized-coal power plants using current technology.

Study Assumptions and Results	Simbeck & McDonald	Alstom *et al.*	Rao & Rubin	Rao & Rubin	Chen *et al.*	Chen *et al.*	Chen *et al.*	Singh *et al.*	Gibbins *et al.*	Range		Gibbins *et al.*	Gibbins *et al.*	Chen *et al.*
	2000	2001	2002	2002	2003	2003	2003	2003	2005	min	max	2006	2006	2003
	AMINE SYSTEM RETROFITS TO EXISTING BOILERS											REPOWERING + CO$_2$ CAPTURE		
Reference Plant (without capture)		*	*	*	*	*	*							
Boiler type (subcritical, super, ultra)	sub	sub	sub	sub	sub	sub	sub		sub			super	super	sub
Coal type (bit, sub-bit, lig) and %S	sub-bit, 0.5%	bit, 2.7%S	sub-bit, 0.5%	sub-bit, 0.5%	sub-bit, 1.1%S	sub-bit, 1.1%S	sub-bit, 1.1%S	sub-bit						
Emission control technologies (SO$_x$/NO$_x$)	none	FGD	none	FGD	FGD	FGD	FGD	not reported	not reported			not reported	not reported	FGD
Reference plant size (MW)	292	434	470	470	248	248	248	400		**248**	**470**			248
Plant capacity factor (%)	80	67	75	75	80	76 (Capture=80)	76 (Capture=80)	91.3	80	**67**	**91**	80	80	80
Net plant efficiency, LHV (%)	36.2	36.2	36.6		33.1	33.1	33.1		36.0	**33**	**37**	43.5	43.5	
Coal cost, LHV (US\$ GJ^{-1})	0.98	1.30	1.25	1.25	1.20	1.20	1.20		3.07	**0.98**	**3.07**	3.07	3.07	1.20
Reference plant emission rate (t CO$_2$ MWh^{-1})	0.901	0.908	0.941	0.95	1.004	1.004	1.004	0.925		**0.90**	**1.00**			1.004
Capture Plant Design														
CO$_2$ capture technology	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA			MEA	KS	Selexol
Other equipment included	new FGD	FGD upgrade	New FGD	FGD upgrade	FGD upgrade	FGD upgrade	FGD upgrade	FGD				Advanced supercrit boiler retrofit	Advanced supercrit boiler retrofit	IGCC (Texaco Q) repower +current steam turbine
Net plant size with capture (MW)	294	255	275	275	140	282	282	400		**140**	**400**			590
Auxilary boiler/fuel used? (type, LHV cost)	NG, \$4.51 GJ^{-1}	none	none	none	none	NG, \$2.59 GJ^{-1}	NG, \$5.06 GJ^{-1}	NG, \$3.79 GJ^{-1}	none			none	none	none
Net plant efficiency, LHV (%)	25.3	21.3	21.4	21.4	18.7				24.0	**19**	**25**	31.5	34.5	32.6
CO$_2$ capture system efficiency (%)	90	96	90	90	90	90	90	90		**90**	**96**			90
CO$_2$ emission rate after capture (t MWh^{-1})	0.113	0.059	0.155	0.16	0.177	0.369	0.369	0.324		**0.06**	**0.37**			0.099
CO$_2$ captured (Mt yr^{-1})	2.090	2.228			1.480	1.480	1.480	2.664		**1.48**	**2.66**			3.684
CO$_2$ product pressure (MPa)	13.7	13.9	13.9	13.9	13.9	13.9	13.9		10.0	**10**	**14**	10.0	10.0	14.5
CCS energy requirement (% more input MWh^{-1})	43	70	71		77				50	**43**	**77**	38	26	
CO$_2$ reduction per kWh (%)	**87**	**94**	**84**	**83**	**82**	**63**	**63**	**65**		**63**	**94**			
Cost Results	**							**						
Cost year basis (constant dollars)	1999	n/a	2000	2000	2000	2000	2000	2001						
Fixed charge factor (%)	12.8	13.0	15.0	15.0	14.8	14.8	14.8	9.4	11.8	**9.4**	**15.0**	11.8	11.8	15
Reference plant TCR (US\$ kW^{-1})	112				0	0	0	0	160	**0**	**160**	480	480	0
Capture plant TCR (US\$ kW^{-1})	1059	1941			837	647	654	846	1028	**647**	**1941**	1282	1170	1493
Incremental TCR for capture (US\$ kW^{-1})	947	1602			837	647	654	846	868	**647**	**1602**	802	690	1493
Reference plant COE (US\$ MWh^{-1})	**18.8**		**18.0**	**18.0**	**20.6**	**20.6**	**20.6**		**26.0**	**18**	**26**	**27.0**	**27.0**	**21**
Capture plant COE (US\$ MWh^{-1})	**54.3**		**70.4**	**66.7**	**66.8**	**51.1**	**62.2**		**65.0**	**51**	**70**	**58.0**	**53.0**	**62.2**
Incremental COE for capture (US\$ MWh^{-1})	**35.5**	**61.7**	**52.4**	**48.7**	**46.2**	**30.6**	**41.7**	**33.2**	**39.0**	**31**	**62**	**31.0**	**26.0**	**41.2**
% increase in capital cost (over ref. plant)														
% increase in COE (over ref. plant)	**189**		**291**	**271**	**225**	**149**	**203**		**150**	**149**	**291**	**115**	**96**	**196**
Cost of CO$_2$ captured (US\$/tCO$_2$)	35	42			31	41	56	40		**31**	**56**			
Cost of CO$_2$ avoided (US\$/tCO$_2$)	45	73	67	59	56	48	66	55		**45**	**73**			46
Capture cost confidence level (see Table 3.6)	moderate											moderate		

Notes: All costs in this table are for capture only and do not include the costs of CO$_2$ transport and storage; see Chapter 8 for total CCS costs. * Reported HHV values converted to LHV assuming LHV/HHV = 0.96 for coal and 0.90 for natural gas. **Reported capital costs increased by 15% to estimate interest during construction and other owners' costs.

Table 3.9 CO_2 capture costs: natural gas-fired power plants using current technology.

Study Assumptions and Results	**Parsons**	**NETL**	**IEA GHG**	**IEA GHG**	**CCP**	**Rubin *et al.***	**Rubin *et al.***	**Range**	
	2002(b)	**2002**	**2004**	**2004**	**2005**	**2005**	**2005**	**min**	**max**
Reference Plant (without capture)	*					*	*		
Plant type (boiler, gas turbine, comb.cycle)	comb.cycle	comb.cycle	comb.cycle	comb.cycle	comb.cycle	comb.cycle	comb.cycle		
Reference plant size (MW)	509	379	776	776	392	507	507	**379**	**776**
Plant capacity factor (%)	65	85	85	85	95	75	50	**50**	**95**
Net plant efficiency, LHV (%)	55.1	57.9	55.6	55.6	57.6	55.8	55.8	**55**	**58**
Fuel cost, LHV ($\text{US\$ GJ}^{-1}$)	2.82	3.55	3.00	3.00	2.96	4.44	4.44	**2.82**	**4.44**
Reference plant emission rate ($tCO_2\ MWh^{-1}$)	0.364	0.344	0.379	0.379	0.37	0.367	0.367	**0.344**	**0.379**
Capture Plant Design									
CO_2 capture technology	MEA	MEA	MEA	KS-1	MEA	MEA	MEA		
Net plant size with capture (MW)	399	327	662	692	323	432	432	**323**	**692**
Net plant efficiency, LHV (%)	47.4	49.9	47.4	49.6	47.4	47.6	47.6	**47**	**50**
CO_2 capture system efficiency (%)	90	90	85	85	86	90	90	**85**	**90**
CO_2 emission rate after capture ($t\ MWh^{-1}$)	0.045	0.040	0.066	0.063	0.063	0.043	0.043	**0.040**	**0.066**
CO_2 captured ($Mt\ yr^{-1}$)	0.949	0.875	1.844	1.844	1.09	1.099	0.733	**0.733**	**1.844**
CO_2 product pressure (MPa)	8.4	10.3	11.0	11.0		13.7	13.7	**8**	**14**
CCS energy requirement (% more input MWh^{-1})	16	16	15	11	22	17	17	**11**	**22**
CO_2 reduction per kWh (%)	**88**	**88**	**83**	**83**	**83**	**88**	**88**	**83**	**88**
Cost Results									
Cost year basis (constant dollars)	2000	2002	2004	2004		2001	2001		
Fixed charge factor (%)			11.0	11.0	11.0	14.8	14.8	**11.0**	**14.8**
Reference plant TCR ($\text{US\$ kW}^{-1}$)	549	515	539	539	724	554	554	**515**	**724**
Capture plant TCR ($\text{US\$ kW}^{-1}$)	1099	911	938	958	1261	909	909	**909**	**1261**
Incremental TCR for capture ($\text{US\$ kW}^{-1}$)	550	396	399	419	537	355	355	**355**	**550**
Reference plant COE ($\text{US\$ MWh}^{-1}$)	**34.2**	**34.7**	**31.3**	**31.3**	**34.2**	**43.1**	**50**	**31**	**50**
Capture plant COE ($\text{US\$ MWh}^{-1}$)	**57.9**	**48.3**	**44**	**43.1**	**51.8**	**58.9**	**72**	**43**	**72**
Incremental COE for capture ($\text{US\$ MWh}^{-1}$)	**23.7**	**13.6**	**12.7**	**11.8**	**17.6**	**15.8**	**22**	**12**	**24**
% increase in capital cost (over ref. plant)	100	77	74	78	74	64	64	**64**	**100**
% increase in COE (over ref. plant)	**69**	**39**	**41**	**38**	51	**37**	**44**	**37**	**69**
Cost of CO_2 captured ($\text{US\$}/tCO_2$)	57	38	34	33	46	41	57	**33**	**57**
Cost of CO_2 avoided ($\text{US\$}/tCO_2$)	74	45	41	37	57	49	68	**37**	**74**
Capture cost confidence level (see Table 3.6)	moderate								

Notes: All costs in this table are for capture only and do not include the costs of CO_2 transport and storage; see Chapter 8 for total CCS costs. * Reported HHV values converted to LHV assuming LHV/HHV = 0.90 for natural gas.

CO_2 reductions (per kWh) of the order of 83-88%, the capital cost per kW increases by 64-100%, while the COE increases by 37-69%, or by 12-24 US\$ MWh^{-1} on an absolute basis. The corresponding cost of CO_2 avoided ranges from 37-74 US\$/tCO_2, while the CCS energy requirement increases plant fuel consumption per kWh by 11-22%.

As seen earlier in Equations (7) to (9), assumptions about the plant fuel cost have an especially important influence on the COE for gas-fired plants because the contribution of capital costs is relatively low compared to coal plants. The studies in Table 3.9 assume stable gas prices of 2.82-4.44 US\$ GJ^{-1} (LHV basis) over the life of the plant, together with high capacity factors (65-95%) representing base load operation. These assumptions result in relatively low values of COE for both the reference plant and capture plant. Since about 2002, however, natural gas prices have increased significantly in many parts of the world, which has also affected the outlook for future prices. Based on the assumptions of one recent study (IEA GHG, 2004), the COE for an NGCC plant without capture would increase by 6.8 US\$ MWh^{-1} for each 1.00 US\$ GJ^{-1} increase in natural gas price (assuming no change in plant utilization or other factors of production). An NGCC plant with CCS would see a slightly higher increase of 7.3 US\$ MWh^{-1}. The price of natural gas, and its relation to the price of competing fuels like coal, is an important determinant of which type of power plant will provide the lowest cost electricity in the context of a particular situation. However, across a twofold increase in gas price (from 3-6 US\$ GJ^{-1}), the incremental cost of CO_2 capture changed by only 2 US\$ MWh^{-1} (US\$ 0.002 kWh^{-1}) with all other factors held constant.

In countries like the US, higher gas prices have also resulted in lower utilization rates (averaging 30-50%) for plants originally designed for base-load operation, but where lower-cost coal plants are available for dispatch. This further raises the average cost of electricity and CO_2 capture for those NGCC plants, as reflected in one case in Table 3.9 with a capacity factor of 50%. In other parts of the world, however, lower-cost coal plants may not be available, or gas supply contracts might limit the ability to curtail gas use. Such situations again illustrate that options for power generation with or without CO_2 capture should be evaluated in the context of a particular situation or scenario.

Studies of commercial post-combustion CO_2 capture applied to simple-cycle gas turbines have been conducted for the special case of retrofitting an auxiliary power generator in a remote location (CCP, 2005). This study reported a relatively high cost of 88 US\$/tCO_2 avoided. Studies of post-combustion capture for gas-fired boilers have been limited to industrial applications, as discussed later in Section 3.7.8.

3.7.5.4 *Biomass-firing and co-firing systems*

Power plants can be designed to be fuelled solely by biomass, or biomass can be co-fired in conventional coal-burning plants. The requirement to reduce net CO_2 emissions could lead to an increased use of biomass fuel, because plants that utilize biomass as a primary or supplemental fuel may be able to take credit for the carbon removed from the atmosphere during the biomass growth cycle. If the biomass carbon released during combustion (as CO_2) is then captured and stored, the net quantity of CO_2 emitted to the atmosphere could in principle be negative.

The most important factor affecting the economics of biomass use is the cost of the biomass. This can range from a negative value, as in the case of some biomass wastes, to costs substantially higher than coal, as in the case of some purposely-grown biomass fuels, or wastes that have to be collected from diffuse sources. Power plants that use only biomass are typically smaller than coal-fired plants because local availability of biomass is often limited and biomass is more bulky and hence more expensive to transport than coal. The smaller sizes of biomass-fired plants would normally result in lower energy efficiencies and higher costs of CO_2 capture. Biomass can be co-fired with coal in larger plants (Robinson *et al.*, 2003). In such circumstances the incremental costs of capturing biomass-derived CO_2 should be similar to costs of capturing coal-derived CO_2. Another option is to convert biomass into pellets or refined liquid fuels to reduce the cost of transporting it over long distances. However, there are costs and emissions associated with production of these refined fuels. Information on costs of CO_2 capture at biomass-fired plants is sparse but some information is given in Section 3.7.8.4. The overall economics of CCS with biomass combustion will depend very much on local circumstances, especially biomass availability and cost and (as with fossil fuels) proximity to potential CO_2 storage sites.

3.7.6 *Pre-combustion CO_2 capture cost for electric power plants (current technology)*

Studies of pre-combustion capture for electric power plants have focused mainly on IGCC systems using coal or other solid fuels such as petroleum coke. This section of the report focuses on currently available technology for CO_2 capture at such plants. As before, the cost of CO_2 capture depends not only on the choice of capture technology, but more importantly on the characteristics and design of the overall power plant, including the fuel type and choice of gasifier. Because IGCC is not widely used for electric power generation at the present time, economic studies of IGCC power plants typically employ design assumptions based on the limited utility experience with IGCC systems and the more extensive experience with gasification in industrial sectors such as petroleum refining and petrochemicals. For oxygen-blown gasifiers, the high operating pressure and relatively high CO_2 concentrations achievable in IGCC systems makes physical solvent absorption systems the predominant technology of interest for pre-combustion CO_2 capture (see Section 3.5.2.11). For purposes of cost reporting, we again distinguish between new plant designs and the retrofitting of existing facilities.

3.7.6.1 *New coal gasification combined cycle power plants*

Table 3.10 summarizes the key assumptions and results of several recent studies of CO_2 capture costs for new IGCC power plants ranging in size from approximately 400-800 MW

Table 3.10 CO_2 capture costs: new IGCC power plants using current technology.

Study Assumptions and Results	**NETL**	**NETL**	**NETL**	**Parsons**	**Simbeck**	**Nsakala, *et al.***	**IEA GHG**	**IEA GHG**	**IEA GHG**	**Rubin *et al.***	**Rubin *et al.***	**Range**	
	2002	**2002**	**2002**	**2002b**	**2002**	**2003**	**2003**	**2003**	**2003**	**2005**	**2005**	**min**	**max**
	PLANTS WITH BITUMINOUS COAL FEEDSTOCK												
Reference Plant without capture)	*	*	*	*		*							
Gasifier name or type	Shell, O_2 blown, CGCU	E-gas, O_2 blown, CGUC	Texaco quench, O_2 blown	E-gas, O_2 blown	Texaco quench, O_2 blown	Texaco syngas cooler, O_2 blown	Texaco quench, O_2 blown	Texaco quench, O_2 blown	Shell, O_2 blown	Texaco quench, O_2 blown	Texaco quench, O_2 blown		
Fuel type (bit, subbit, lig; other) and %S	Illinois #6	Illinois #6	Illinois #6	bit, 2.5% S	bit, 1% S	bit	bit, 1%S	bit, 1%S	bit, 1%S	bit, 2.1%S	bit, 2.1%S		
Reference plant size (MW)	413	401	571	425	521		827	827	776	527	527	**401**	**827**
Plant capacity factor (%)	85	85	65	65	80	80	85	85	85	75	65	**65**	**85**
Net plant efficiency, LHV (%)	47.4	46.7	39.1	44.8	44.6		38.0	38.0	43.1	39.1	39.1	**38**	**47**
Fuel cost, LHV (US\$ GJ^{-1})	1.03	1.03	1.28	1.29	0.98	1.23	1.50	1.50	1.50	1.25	1.25	**0.98**	**1.50**
Reference plant emission rate ($tCO_2\ MWh^{-1}$)	0.682	0.692	0.846	0.718	0.725		0.833	0.833	0.763	0.817	0.817	**0.68**	**0.85**
Capture Plant Design													
CO_2 capture technology	Selexol	Selexol	Selexol	Selexol	Selexol	Selexol	Selexol	Selexol, NS	Selexol	Selexol	Selexol		
Net plant size, with capture (MW)	351	359	457	404	455		730	742	676	492	492	**351**	**742**
Net plant efficiency, LHV (%)	40.1	40.1	31.3	38.5	39.0	31.5	31.5	32.0	34.5	33.8	33.8	**31**	**40**
CO_2 capture system efficiency (%)	89.2	87.0	89.0	91.0	91.2		85	85	85	90	90	**85**	**91**
CO_2 emission rate after capture ($t\ MWh^{-1}$)	0.087	0.105	0.116	0.073	0.065	0.104	0.152	0.151	0.142	0.097	0.097	**0.07**	**0.15**
CO_2 captured (Mt/yr)	1.803	1.870	2.368	1.379	2.151		4.682	4.728	4.050	2.749	2.383	**1.38**	**4.73**
CO_2 product pressure (MPa)	14.5	14.5	8.3	8.3			11.0	11.0	11.0	13.7	13.7	**8**	**14**
CCS energy requirement (% more input MWh^{-1})	18	16	25	16	14		21	19	25	16	16	**14**	**25**
CO_2 reduction per kWh (%)	**87**	**85**	**86**	**90**	**91**		**82**	**82**	**81**	**88**	**88**	**81**	**91**
Cost Results							**	**	**				
Cost year basis (constant dollars)	2002	2002	2002	2000	2000		2002	2002	2002	2001	2001		
Fixed charge factor (%)	14.8	14.8	15.0	13.8	13.0		11.0	11.0	11.0	14.8	17.3	**11**	**17**
Reference plant TCR (US\$ kW^{-1})	1370	1374	1169	1251	1486	1565	1187	1187	1371	1311	1311	**1169**	**1565**
Capture plant TCR (US\$ kW^{-1})	2270	1897	1549	1844	2067	2179	1495	1414	1860	1748	1748	**1414**	**2270**
Incremental TCR for capture (US\$ kW^{-1})	900	523	380	593	581	614	308	227	489	437	437	**227**	**900**
Reference plant COE (US\$ MWh^{-1})	**40.6**	**40.9**	**43.4**	**47.7**	**43.0**	**53.0**	**45.0**	**45.0**	**48.0**	**48.3**	**61**	**41**	**61**
Capture plant COE (US\$ MWh^{-1})	**62.9**	**54.4**	**59.9**	**65.8**	**57.7**	**71.5**	**56.0**	**54.0**	**63.0**	**62.6**	**79**	**54**	**79**
Incremental COE for capture (US\$ MWh^{-1})	**22.3**	**13.5**	**16.5**	**18.1**	**14.7**	**18.5**	**11**	**9**	**15**	**14.3**	**18.2**	**9**	**22**
% increase in capital cost (over ref. plant)	66	38	33	47	39	39	26	19	36	33	33	**19**	**66**
% increase in COE (over ref. plant)	55	33	38	38	34	**35**	**24**	**20**	**31**	30	30	**20**	**55**
Cost of CO_2 captured (US\$/tCO_2)	32	19	18	30	21		13	11	19	17	21	**11**	**32**
Cost of CO_2 avoided (US\$/tCO_2)	37	23	23	28	22	23	16	13	24	20	25	**13**	**37**
Capture cost confidence level (see Table 3.6)	moderate												

Notes: All costs in this table are for capture only and do not include the costs of CO_2 transport and storage; see Chapter 8 for total CCS costs. * Reported HHV values converted to LHV assuming LHV/HHV = 0.96 for coal. ** Reported capital costs increased by 8% to include interest during construction. **Reported capital costs increased by 15% to estimate interest during construction and other owners' costs.

Table 3.10. *Continued.*

Study Assumptions and Results	**Stobbs & Clark 2005**	**Stobbs & Clark 2005**	**Stobbs & Clark 2005**	**IEA GHG 2000b**
	PLANTS WITH OTHER FEEDSTOCKS			
Reference Plant without capture)				
Gasifier name or type		Texaco quench, O_2 blown	Shell, O_2 blown	O_2 blown, partial oxidation
Fuel type (bit, subbit, lig; other) and %S	bit	Sub-bit	Lignite	Natural gas
Reference plant size (MW)	[No IGCC Reference Plants]			790
Plant capacity factor (%)	90	90	90	90
Net plant efficiency, LHV (%)				56.2
Fuel cost, LHV (US$ GJ^{-1})	1.90	0.48	0.88	2.00
Reference plant emission rate (tCO_2 MWh^{-1})				0.370
Capture Plant Design				
CO_2 capture technology	Selexol	Selexol	Selexol	Selexol
Net plant size, with capture (MW)	445	437	361	820
Net plant efficiency, LHV (%)	32.8	27.0	28.3	48.3
CO_2 capture system efficiency (%)	87	92	86	85
CO_2 emission rate after capture (t MWh^{-1})	0.130	0.102	0.182	0.065
CO_2 captured (Mt/yr)	3.049	4.040	3.183	2.356
CO_2 product pressure (MPa)	13.9	13.9	13.9	11.0
CCS energy requirement (% more input MWh^{-1})				14
CO_2 reduction per kWh (%)				**82**
Cost Results	***	***	***	**
Cost year basis (constant dollars)	2003	2003	2003	2000
Fixed charge factor (%)				11.0
Reference plant TCR (US$ kW^{-1})				447
Capture plant TCR (US$ kW^{-1})	2205	2518	3247	978
Incremental TCR for capture (US$ kW^{-1})				531
Reference plant COE (US$ MWh^{-1})				21.6
Capture plant COE (US$ MWh^{-1})	68.4	62.1	83.9	34.4
Incremental COE for capture (US$ MWh^{-1})				12.8
% increase in capital cost (over ref. plant)				119
% increase in COE (over ref. plant)				**59**
Cost of CO_2 captured (US$/$tCO_2$)				35
Cost of CO_2 avoided (US$/$tCO_2$)	31	33	56	42
Capture cost confidence level (see Table 3.6)	moderate			moderate

Notes: All costs in this table are for capture only and do not include the costs of CO_2 transport and storage; see Chapter 8 for total CCS costs. * Reported HHV values converted to LHV assuming LHV/HHV = 0.96 for coal. ** Reported capital costs increased by 8% to include interest during construction. ***Reported capital costs increased by 15% to estimate interest during construction and other owners' costs.

net power output. While several gasifiers and coal types are represented, most studies focus on the oxygen-blown Texaco quench system,[10] and all but one assume bituminous coals. CO_2 capture efficiencies across these studies range from 85-92% using commercially available physical absorption systems. The energy requirements for capture increase the overall plant heat rate (energy input per kWh) by 16-25%, yielding net CO_2 reductions per kWh of 81-88%. Other study variables that influence total plant cost and the cost of CO_2 capture include the fuel cost, CO_2 product pressure, plant capacity factor and fixed charge factor. Many of the recent studies also include the cost of a spare gasifier to ensure high system reliability.

Table 3.10 indicates that for studies based on the Texaco or E-Gas gasifiers, CO_2 capture adds approximately 20-40% to both the capital cost (US$ kW^{-1}) and the cost of electricity (US$ MWh^{-1}) of the reference IGCC plants, while studies using the Shell gasifier report increases of roughly 30-65%. The total COE reported for IGCC systems ranges from 41-61 US$ MWh^{-1} without capture and 54-79 US$ MWh^{-1} with capture. With capture, the lowest COE is found for gasifier systems with quench cooling designs that have lower thermal efficiencies than the more capital-intensive designs with heat recovery systems. Without capture, however, the latter system type has the lowest COE in Table 3.10. Across all studies, the cost of CO_2 avoided ranges from 13-37 US$/$tCO_2$ relative to an IGCC without capture, excluding transport and storage costs. Part of the reason for this lower incremental cost of CO_2 capture relative to coal combustion plants is the lower average energy requirement for IGCC systems. Another key factor is the smaller gas volume treated in oxygen-blown gasifier systems, which substantially reduces equipment size and cost.

As with PC plants, Table 3.10 again emphasizes the importance of plant financing and utilization assumptions on the calculated cost of electricity, which in turn affects CO_2-capture costs. The lowest COE values in this table are for plants with a low fixed charge rate and high capacity factor, while

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[10] In 2004, the Texaco gasifier was re-named as the GE gasifier following acquisition by GE Energy (General Electric). However, this report uses the name Texaco, as it is referred to in the original references cited.

substantially higher COE values result from high financing costs and lower plant utilization. Similarly, the type and properties of coal assumed has a major impact on the COE, as seen in a recent Canadian Clean Power Coalition study, which found substantially higher costs for low-rank coals using a Texaco-based IGCC system (Stobbs and Clark, 2005, Table 3.10). EPRI also reports higher IGCC costs for low-rank coals (Holt *et al.*, 2003). On the other hand, where plant-level assumptions and designs are similar across studies, there is relatively little difference in the estimated costs of CO_2 capture based on current commercial technology. Similarly, the several studies in Tables 3.7 and 3.10 that estimate costs for both IGCC and PC plants on an internally consistent basis, all find that IGCC plants with capture have a lower COE than PC plants with capture. There is not yet a high degree of confidence in these cost estimates, however (see Table 3.6).

The costs in Table 3.10 also reflect efforts in some studies to identify least-cost CO_2 capture options. For example, one recent study (IEA GHG, 2003) found that capture and disposal of hydrogen sulphide (H_2S) along with CO_2 can reduce overall capture costs by about 20% (although this may increase transport and storage costs, as discussed in Chapters 4 and 5). The feasibility of this approach depends in a large part on applicable regulatory and permitting requirements. Advanced IGCC designs that may further reduce future CO_2 capture costs are discussed in Section 3.7.7.

3.7.6.2 Repowering of existing coal-fired plants with IGCC

For some existing coal-fired power plants, an alternative to the post-combustion capture systems discussed earlier is repowering with an IGCC system. In this case - depending on site-specific circumstances - some existing plant components, such as the steam turbine, might be refurbished and utilized as part of an IGCC plant. Alternatively, the entire combustion plant might be replaced with a new IGCC system while preserving other site facilities and infrastructure.

Although repowering has been widely studied as an option to improve plant performance and increase plant output, there are relatively few studies of repowering motivated by CO_2 capture. Table 3.8 shows results from one recent study (Chen et *al.*, 2003) which reports CO_2 capture costs for IGCC repowering of a 250 MW coal-fired unit that is assumed to be a fully amortized (hence, a low COE of 21 US\$ MWh^{-1}). IGCC repowering yielded a net plant capacity of 600 MW with CO_2 capture and a COE of 62-67 US\$ MWh^{-1} depending on whether or not the existing steam turbine can be reused. The cost of CO_2 avoided was 46-51 US\$/tCO_2. Compared to the option of retrofitting the existing PC unit with an amine-based capture system and retaining the existing boiler (Table 3.8), the COE for IGCC repowering was estimated to be 10-30% lower. These findings are in general agreement with earlier studies by Simbeck (1999). Because the addition of gas turbines roughly triples the gross plant capacity of a steam-electric plant, candidates for IGCC repowering are generally limited to smaller existing units (e.g., 100-300 MW). Taken together with the post-combustion retrofit studies in Table 3.8, the most cost-effective options for existing plants involve combining CO_2 capture with plant upgrades that increase overall efficiency and net output. Additional studies would be needed to systematically compare the feasibility and cost of IGCC repowering to supercritical boiler upgrades at existing coal-fired plants.

3.7.7 CO_2 capture cost for hydrogen production and multi-product plants (current technology)

While electric power systems have been the dominant technologies of interest for CO_2 capture studies, other industrial processes, including hydrogen production and multi-product plants producing a mix of fuels, chemicals and electricity also are of interest. Because CO_2 capture cost depends strongly on the production process in question, several categories of industrial processes are discussed below.

3.7.7.1 Hydrogen production plants

Section 3.5 discussed the potential role of hydrogen as an energy carrier and the technological options for its production. Here we examine the cost of capturing CO_2 normally released during the production of hydrogen from fossil fuels. Table 3.11 shows the key assumptions and cost results of recent studies of CO_2 capture costs for plants with hydrogen production rates of 155,000-510,000 $Nm^3 h^{-1}$ (466-1531 MW_t), employing either natural gas or coal as a feedstock. The CO_2 capture efficiency for the hydrogen plant ranges from 87-95% using commercially available chemical and physical absorption systems. The CO_2 reduction per unit of product is lower, however, because of the process energy requirements and because of additional CO_2 emitted by an offsite power plant assumed in some of these studies. As hydrogen production requires the separation of H_2 from CO_2, the incremental cost of capture is mainly the cost of CO_2 compression.

At present, hydrogen is produced mainly from natural gas. Two recent studies (see Table 3.11) indicate that CO_2 capture would add approximately 18-33% to the unit cost of hydrogen while reducing net CO_2 emissions per unit of H_2 product by 72-83% (after accounting for the CO_2 emissions from imported electricity). The total cost of hydrogen is sensitive to the cost of feedstock, so different gas prices would alter both the absolute and relative costs of CO_2 capture.

For coal-based hydrogen production, a recent study (NRC,2004) projects an 8% increase in the unit cost of hydrogen for an 83% reduction in CO_2 emissions per unit of product. Again, this figure includes the CO_2 emissions from imported electricity.

3.7.7.2 Multi-product plants

Multi-product plants (also known as polygeneration plants) employ fossil fuel feedstocks to produce a variety of products such as electricity, hydrogen, chemicals and liquid fuels. To calculate the cost of any particular product (for a given rate of return), economic analyses of multi-product plants require that the selling price of all other products be specified over the operating life of the plant. Such assumptions, in addition to

Table 3.11. CO_2 capture costs: Hydrogen and multi-product plants using current or near-commercial technology. (Continued on next page)

Study Assumptions and Results	**HYDROGEN AND ELECTRICITY PRODUCTS**								
	Simbeck	**NRC**	**NRC**	**Parsons**	**Mitretek**	**Kreutz *et al.***	**Kreutz *et al.***	**Range**	
	2005	**2004**	**2004**	**2002a**	**2003**	**2005**	**2005**	**min**	**max**
Reference Plant (without capture)	*			*	*				
Plant products (primary/secondary)	H_2	H_2	H_2	H_2+ electricity	H_2+ electricity	H_2+ electricity	H_2+ electricity		
Production process or type	Steam reforming	Steam reforming	Texaco quench, CGCU	Conv E-Gas, CGCU, H_2SO_4 co-product	Texaco quench, CGCU, Claus/Scot sulphur co-product	Texaco quench	Texaco quench		
Feedstock	Natural gas	Natural gas	Coal	Pgh #8 Coal	Coal	Coal	Coal		
Feedstock cost, LHV (US\$ GJ^{-1})	5.26	4.73	1.20	0.89	1.03	1.26	1.26	**0.89**	**5.26**
Ref. plant input capacity, LHV (GJ h^{-1})	9848	7235	8861	2627	2954	6706	6706	**2627**	**9848**
Ref plant output capacity, LHV: Fuels (GJ h^{-1})	7504	5513	6004	1419	1579	3853	3853	**1419**	**7504**
Electricity (MW)	-44	-32	-121	38	20	78	78	**-121**	**78**
Net plant efficiency, LHV (%)	74.6	74.6	62.9	59.2	55.9	61.7	61.7	**55.9**	**74.6**
Plant capacity factor (%)	90	90	90	80	85	80	80	**80**	**90**
CO_2 emitted ($MtCO_2$ yr^{-1})	4.693	3.339	7.399	1.795	2.148	4.215	4.215	**1.80**	**7.40**
Carbon exported in fuels (MtC yr^{-1})	0	0	0	0	0	0	0	**0**	**0**
Total carbon released (kg CO_2 GJ^{-1} products)	81	78	168	164	174	145	145	**78**	**174**
Capture Plant Design									
CO_2 capture/separation technology	Amine scrubber, SMR flue gas	MEA scrubber	Not reported	Selexol	Not reported	Selexol	CO_2 H_2S co-capture, Selexol		
Capture plant input capacity, LHV (GJ h^{-1})	11495	8339	8861	2627	2954	6706	6706	**2627**	**11495**
Capture plant output capacity, LHV: Fuels (GJ h^{-1})	7504	6004	6004	1443	1434	3853	3853	**1434**	**7504**
Electricity (MW)	-129	-91	-187	12	27	39	35	**-187**	**39**
Net plant efficiency, LHV (%)	61.2	68.1	60.2	56.6	51.8	59.5	59.3	**51.8**	**68.1**
CO_2 capture efficiency (%)**	90	90	90	92	87	91	95	**87**	**95**
CO_2 emitted ($MtCO_2$ yr^{-1})***	1.280	0.604	1.181	0.143	0.279	0.338	0.182	**0.14**	**1.280**
Carbon exported in fuels (MtC yr^{-1})	0	0	0	0	0	0	0	**0.0**	**0**
Total carbon released (kgCO_2 GJ^{-1} products)	23.0	13.5	28.1	13.7	24.5	12.1	6.5	**6.5**	**28.1**
CO_2 captured ($MtCO_2$ yr^{-1})	4.658	3.378	6.385	1.654	1.869	3.882	4.037	**1.7**	**6.4**
CO_2 product pressure (MPa)	13.7	13.7	13.7	13.4	20	15	15	**13.4**	**20.0**
CCS energy requirement (% more input/GJ plant output)	21.8	9.5	4.5	4.7	7.9	3.6	3.9	**3.6**	**21.8**
CO_2 reduction per unit product (%)	72	83	83	92	86	92	96	**72**	**96**
Cost Results									
Cost year basis (constant dollars)	2003	2000	2000	2000	2000	2002	2002		
Fixed charge rate (%)	20.0	16.0	16.0	14.3	13.0	15.0	15.0	**13.0**	**20.0**
Reference plant TCR (million US\$)****	668	469	1192	357	365	887	887	**357**	**1192**
Capture plant TCR (million US\$)****	1029	646	1218	415	409	935	872	**409**	**1218**
% increase in capital cost (%)	54.1	37.7	2.2	16.5	11.9	5.4	-1.7	**-1.7**	**54.1**
Ref. plant electricity price (US\$ MWh^{-1})	50.0	45.0	45.0	30.8	35.6	46.2	46.2	**30.8**	**50.0**
Capture plant electricity price (US\$ MWh^{-1})	50.0	45.0	45.0	30.8	53.6	62.3	60.5	**30.8**	**62.3**
% increase in assumed electricity price	0.0	0.0	0.0	0.0	50.6	34.8	31.0	**0.0**	**50.6**
Ref. plant fuel product cost, LHV (US\$ GJ^{-1})	**10.03**	**8.58**	**7.99**	**6.51**	**7.29**	**7.19**	**7.19**	**6.51**	**10.03**
Capture plant fuel product cost, LHV (US\$ GJ^{-1})	**13.29**	**10.14**	**8.61**	**7.90**	**8.27**	**7.86**	**7.52**	**7.52**	**13.29**
Increase in fuel product cost (US\$ GJ^{-1})	**3.26**	**1.56**	**0.62**	**1.38**	**0.98**	**0.67**	**0.32**	**0.32**	**3.26**
% increase in fuel product cost	**32.5**	**18.2**	**7.7**	**21.1**	**13.4**	**9.3**	**4.5**	**4.5**	**32.5**
Cost of CO_2 captured (US\$/tCO_2)	38.9	20.7	4.1	8.7	6.0	4.8	2.2	**2.2**	**38.9**
Cost of CO_2 avoided (US\$/tCO_2)	56.3	24.1	4.4	9.2	6.5	5.0	2.3	**2.3**	**56.3**
Confidence level (see Table 3.6)	high		high	moderate					

Notes: All costs in this table are for capture only and do not include the costs of CO_2 transport and storage; see Chapter 8 for total CCS costs. * Reported HHV values converted to LHV assuming LHV/HHV = 0.96 for coal, 0.846 for hydrogen, and 0.93 for F-T liquids. ** CO_2 capture efficiency = (C in CO_2 captured) /(C in fossil fuel input to plant - C in carbonaceous fuel products of plant) x100; C associated with imported electricity is not included. ***Includes CO_2 emitted in the production of electricity imported by the plant. ****Reported total plant investment values increased by 3.5% to estimate total capital requirement.

those discussed earlier, can significantly affect the outcome of cost calculations when there is not one dominant product at the facility.

Several of the coal-based hydrogen production plants in Table 3.11 also produce electricity, albeit in small amounts (in fact, smaller than the electricity quantities purchased by the stand-alone plants). Most of these studies assume that the value of the electricity product is higher under a carbon capture regime than without CO_2 capture. The result is a 5-33% increase in hydrogen production cost for CO_2 reductions of 72-96% per unit of product. The case with the lowest incremental product cost and highest CO_2 reduction assumes co-disposal of H_2S with CO_2, thus eliminating the costs of sulphur capture and recovery. As noted earlier (Section 3.7.6.1), the feasibility of this option depends strongly on local regulatory requirements; nor are higher costs for transport and storage reflected in the Table 3.11 cost estimate for this case.

Table 3.11 also presents examples of multi-product plants

Table 3.11. *Continued.*

Study Assumptions and Results	LIQUID FUEL AND ELECTRICITY PRODUCTS										
	Mitretek	**Larson/Ren**	**Larson/Ren**	**Larson/Ren**	**Larson/Ren**	**Celik *et al.***	**Celik *et al.***	**Celik *et al.***	**Celik *et al.***	**Range**	
	2003	**2003**	**2003**	**2003**	**2003**	**2005**	**2005**	**2005**	**2005**	**min**	**max**
Reference Plant (without capture)	*										
Plant products (primary/secondary)	F-T liquids + electricity	MeOH +electricity	MeOH +electricity	DME +electricity	DME +electricity	DME + electricity	DME + electricity	DME + electricity	DME + electricity		
Production process or type	Unspecified O_2-blown gasifier, unspecified synthesis reactor	Texaco quench, Liquid phase reactor, Once-through config.	Texaco quench, Liquid phase reactor, Once-through config.	Texaco quench, Liquid phase reactor, Once-through config.	Texaco quench, Liquid phase reactor, Once-through config.	Texaco quench, Liquid phase reactor, Once-through config.	Texaco quench, Liquid phase reactor, Once-through config.	Texaco quench, Liquid phase reactor, Once-through config.	Texaco quench, Liquid phase reactor, Once-through config.		
Feedstock	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal		
Feedstock cost, LHV (US\$ GJ^{-1})	1.09	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	**1.00**	**1.09**
Ref. plant input capacity, LHV ($GJ h^{-1}$)	16136	9893	9893	8690	8690	7931	7931	7931	7931	**7931**	**16136**
Ref plant output capacity, LHV: Fuels ($GJ h^{-1}$)	7161	2254	2254	2160	2160	2161	2161	2161	2161	**2160**	**7161**
Electricity (MW)	697	625	625	552	552	490	490	490	490	**490**	**697**
Net plant efficiency, LHV (%)	59.9	45.5	45.5	47.7	47.7	49.5	49.5	49.5	49.5	**45.5**	**59.9**
Plant capacity factor (%)	90	85	85	85	85	80	80	80	80	**80**	**90**
CO_2 emitted ($MtCO_2\ yr^{-1}$)	8.067	5.646	5.646	4.895	4.895	4.077	4.077	4.077	4.077	**4.08**	**8.07**
Carbon exported in fuels ($MtC\ yr^{-1}$)	1.190	0.317	0.317	0.334	0.334	0.274	0.274	0.274	0.274	**0.27**	**1.19**
Total carbon released ($kgCO_2\ GJ^{-1}$ products)	163	203	203	198	198	185	185	185	185	**163**	**203**
Capture Plant Design											
CO_2 capture/separation technology	Amine scrubber	Selexol	CO_2 H_2S co-capture. Selexol	Selexol	CO_2 H_2S co-capture. Selexol	CO_2 H_2S co-capture. Rectisol	CO_2 H_2S co-capture. Rectisol	CO_2 H_2S co-capture. Rectisol	CO_2 H_2S co-capture. Rectisol		
Capture plant input capacity, LHV ($GJ h^{-1}$)	16136	9893	9893	8690	Coal	7931	7931	7931	7931	**7931**	**16136**
Capture plant output capacity LHV: Fuels ($GJ h^{-1}$)	7242	2254	2254	2160	2160	2161	2160	2160	2160	**2160**	**7242**
Electricity (MW)	510	582	577	531	527	469	367	365	353	**353**	**582**
Net plant efficiency, LHV (%)	56.3	44.0	43.8	46.9		48.5	43.9	43.8	43.2	**43**	**56**
CO_2 capture efficiency (%)**	91	58	63	32	37	36	89	92	97	**32**	**97**
CO_2 emitted ($MtCO_2\ yr^{-1}$)***	0.733	2.377	2.099	3.320	3.076	2.598	0.390	0.288	0.028	**0.03**	**3.32**
Carbon exported in fuels ($MtC\ yr^{-1}$)	1.2	0.317	0.317	0.294	0.294	0.274	0.274	0.274	0.274	**0.274**	**1.200**
Total carbon released ($kgCO_2\ GJ^{-1}$ products)	71.7	109.2	101.0	144.9	137.4	134	57	53	43	**43**	**145**
CO_2 captured ($MtCO_2\ yr^{-1}$)	7.260	3.269	3.547	1.574	1.819	1.479	3.692	3.790	4.021	**1.48**	**7.26**
CO_2 product pressure (MPa)	13.8	15	15	15	15	15	15	15	15	**14**	**15**
CCS energy requirement. (% more input/GJ plant output)	6.5	3.6	4.0	1.9		2.0	12.8	13.0	14.5	**1.9**	**14.5**
CO_2 reduction/unit product (%)	56	46	50	27	31					**27**	**56**
Cost Results											
Cost year basis (constant dollars)						2003	2003	2003	2003		
Fixed charge rate (%)	12.7	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	**12.7**	**15.0**
Reference plant TCR (million US\$)****	2160	1351	1351	1215	1215	1161	1161	1161	1161	**1161**	**2160**
Capture plant TCR (million US\$)****	2243	1385	1220	1237	1090	1066	1128	1164	1172	**1066**	**2243**
% increase in capital cost (%)	3.8	2.6	-9.7	1.8	-10.3	-8.1	-2.8	0.2	0.9	**-10.3**	**3.8**
Ref. plant electricity price (US\$ MWh^{-1})	35.6	42.9	42.9	42.9	42.9	44.1	44.1	44.1	44.1	**35.6**	**44.1**
Capture plant electricity price (US\$ MWh^{-1})	53.6	42.9	42.9	42.9	42.9	58.0	58.0	58.0	58.0	**42.9**	**58.0**
% increase in assumed elec. price	50.5	0.0	0.0	0.0	0.0	31.5	31.5	31.5	31.5	**0.0**	**50.5**
Ref. plant fuel product cost, LHV (US\$ GJ^{-1})	**5.58**	**9.12**	**9.12**	**8.68**	**8.68**	**7.41**	**7.41**	**7.41**	**7.41**	5.6	9.1
Capture plant fuel product cost, LHV (US\$ GJ^{-1})	**5.43**	**10.36**	**8.42**	**9.37**	**7.57**	**6.73**	**7.18**	**7.65**	**8.09**	5.4	10.4
Increase in fuel product cost (US\$ GJ^{-1})	**-0.15**	**1.24**	**-0.70**	**0.69**	**-1.11**	**-0.68**	**-0.23**	**0.24**	**0.68**	-1.1	1.2
% increase in fuel product cost	**-5.7**	**13.6**	**-7.7**	**7.9**	**-12.8**	**-9.2**	**-3.1**	**3.2**	**9.2**	**-12.8**	**13.6**
Cost of CO_2 captured (US\$/tCO_2)		12.3	-6.4	13.3	-18.4	-12.4	-1.5	1.5	4.1	**-18.4**	**13.3**
Cost of CO_2 avoided (US\$/tCO_2)		13.2	-6.9	13.0	-18.3	-13.3	-1.8	1.8	4.8	**-18.3**	**13.2**
Confidence level (see Table 3.6)	moderate	moderate	moderate	low to moderate							

Notes: All costs in this table are for capture only and do not include the costs of CO_2 transport and storage; see Chapter 8 for total CCS costs. * Reported HHV values converted to LHV assuming LHV/HHV = 0.96 for coal, 0.846 for hydrogen, and 0.93 for F-T liquids. ** CO_2 capture efficiency = (C in CO_2 captured)/(C in fossil fuel input to plant - C in carbonaceous fuel products of plant) x100; C associated with imported electricity is not included. ***Includes CO_2 emitted in the production of electricity imported by the plant. ****Reported total plant investment values increased by 3.5% to estimate total capital requirement.

producing liquid fuels plus electricity. In these cases the amounts of electricity produced are sizeable compared to the liquid products, so the assumed selling price of electricity has a major influence on the product cost results. So too does the assumption in two of the cases of co-disposal of H_2S with CO_2 (as described above). For these reasons, the incremental cost of CO_2 capture ranges from a 13% decrease to a 13% increase in fuel product cost relative to the no-capture case. Note too that the overall level of CO_2 reductions per unit of product is only 27-56%. This is because a significant portion of carbon in the coal feedstock is exported with the liquid fuel products. Nonetheless, an important benefit of these fuel-processing schemes is a reduction (of 30-38%) in the carbon content per unit of fuel energy relative to the feedstock fuel. To the extent these liquid fuels displace other fuels with higher carbon per unit of energy, there is a net benefit in end-use CO_2 emissions when the fuels are burned. However, no credit for such reductions is taken in Table 3.11 because the system boundary considered is confined to the fuel production plant.

3.7.8 Capture costs for other industrial processes (current technology)

CO_2 can be captured in other industrial processes using the techniques described earlier for power generation. While the costs of capture may vary considerably with the size, type and location of industrial processes, such costs will be lowest for processes or plants having: streams with relatively high CO_2 concentrations; process plants that normally operate at high load factors; plants with large CO_2 emission rates; and, processes that can utilize waste heat to satisfy the energy requirements of CO_2 capture systems. Despite these potential advantages, little detailed work has been carried out to estimate costs of CO_2 capture at industrial plants, with most work focused on oil refineries and petrochemical plants. A summary of currently available cost studies appears in Table 3.12.

3.7.8.1 Oil refining and petrochemical plants

Gas-fired process heaters and steam boilers are responsible for the bulk of the CO_2 emitted from typical oil refineries and petrochemical plants. Although refineries and petrochemical plants emit large quantities of CO_2, they include multiple emission sources often dispersed over a large area. Economies of scale can be achieved by using centralized CO_2 absorbers or amine regenerators but some of the benefits are offset by the cost of pipes and ducts. Based on Table 3.14, the cost of capturing and compressing CO_2 from refinery and petrochemical plant heaters using current technology is estimated to be 50-60 US\$/tCO_2 captured. Because of the complexity of these industrial facilities, along with proprietary concerns, the incremental cost of plant products is not normally reported.

High purity CO_2 is currently vented to the atmosphere by some gas processing and petrochemical plants, as described in Chapter 2. The cost of CO_2 capture in such cases would be simply the cost of drying and compressing the CO_2 to the pressure required for transport. The cost would depend on various factors, particularly the scale of operation and the electricity price. Based on 2 MtCO_2 yr^{-1} and an electricity price of US\$ 0.05 kWh^{-1}, the cost is estimated to be around 10 US\$/tCO_2 emissions avoided. Electricity accounts for over half of the total cost.

3.7.8.2 Cement plants

As noted in Chapter 2, cement plants are the largest industrial source of CO_2 apart from power plants. Cement plants normally burn lower cost high-carbon fuels such as coal, petroleum coke and various wastes. The flue gas typically has a CO_2 concentration of 14-33% by volume, significantly higher than at power plants, because CO_2 is produced in cement kilns by decomposition of carbonate minerals as well as by fuel combustion. The high CO_2 concentration would tend to reduce the specific cost of CO_2 capture from flue gas. Pre-combustion capture, if used, would only capture the fuel-related CO_2, so would be only a partial solution to CO_2 emissions. Oxy-fuel combustion and capture using calcium sorbents are other options, which are described in Sections 3.2.4 and 3.7.11.

3.7.8.3 Integrated steel mills

Integrated steel mills are some of the world's largest emitters of CO_2, as described in Chapter 2. About 70% of the carbon introduced into an integrated steel mill is contained in the blast furnace gas in the form of CO_2 and CO, each of which comprise about 20% by volume of the gas. The cost of capturing CO_2 from blast furnace gas was estimated to be 35 US\$/tCO_2 avoided (Farla *et al.*, 1995) or 18 US\$/tCO_2 captured (Gielen, 2003).

Iron ore can be reacted with synthesis gas or hydrogen to produce iron by direct reduction (Cheeley, 2000). Direct reduction processes are already used commercially but further development work would be needed to reduce their costs so as to make them more widely competitive with conventional iron production processes. The cost of capturing CO_2 from a direct reduction iron (DRI) production processes was estimated to be 10 US\$/tCO_2 (Gielen, 2003). CO_2 also could be captured from other gases in iron and steel mills but costs would probably be higher as they are more dilute or smaller in scale.

3.7.8.4 Biomass plants

The main large point sources of biomass-derived CO_2 are currently wood pulp mills, which emit CO_2 from black liquor recovery boilers and bark-fired boilers, and sugar/ethanol mills, which emit CO_2 from bagasse-fired boilers. Black liquor is a byproduct of pulping that contains lignin and chemicals used in the pulping process. The cost of post-combustion capture was estimated to be 34 US\$/tCO_2 avoided in a plant that captures about 1 MtCO_2 yr^{-1} (Möllersten *et al.*, 2003). Biomass gasification is under development as an alternative to boilers.

CO_2 could be captured from sucrose fermentation and from combustion of sugar cane bagasse at a cost of about 53 US\$/tCO_2 avoided for a plant capturing 0.6 MtCO_2 yr^{-1} avoided (Möllersten *et al.*, 2003). CO_2 from sugar cane fermentation has a high purity, so only drying and compression is required. The overall cost is relatively high due to an annual load factor that is lower than that of most power stations and large industrial

Table 3.12. Capture costs: Other industrial processes using current or advanced technology.

Study Assumptions and Cost Results	CURRENT TECHNOLOGY									ADVANCED TECHNOLOGY			
	Farla *et al.*	**IEA GHG**	**IEA GHG**	**IEA GHG**	**Möllersten *et al.***	**Möllersten *et al.***	**Möllersten *et al.***	**CCP**	**CCP**	**CCP**	**CCP**	**CCP**	**CCP**
	1995	**2000c**	**2000c**	**2002b**	**2003**	**2003**	**2003**	**2005**	**2005**	**2005**	**2005**	**2005**	**2005**
Reference Plant (without capture)													
Industrial process	Iron production												
Oil refining petrochemical	Oil refining petrochemical	High purity CO_2 sources	Pulp mill	Pulp mill	Ethanol fermentation	Refinery heaters & boilers	Small gas turbines		Refinery heaters & boilers	Small gas turbines	Small gas turbines		
Feedstock type	Coke	Refinery gas/ natural gas	Refinery gas/ natural gas		Black liquor and bark	Black liquor	Sugar cane	Mixed	NG	Mixed	Mixed	Natural gas	Natural gas
Plant size (specify units)	168 kg s^{-1} iron	315 kg s^{-1} crude oil	315 kg s^{-1} crude oil		17.9 kg s^{-1} pulp	17.9 kg s^{-1} pulp	9.1 kg s^{-1} ethanol	1351 MWt	358 MWt	1351 MWt	1351 MWt	358 MWt	358 MWt
Plant capacity factor (%)	95.3	90	90	90	90.4	90.4	49.3	90.4	98.5	90.4	90.4	98.5	98.5
Feedstock cost (US$ per unit specified)					US\$3 GJ^{-1} LHV	US\$3 GJ^{-1} LHV							
Ref. plant emission rate ($kgCO_2$ MWh^{-1})								0.22	0.82	0.22	0.22	0.82	0.82
Capture Plant Design													
CO_2 capture/separation technology	MDEA	MEA	Pre-combustion	Compression only	Amine	Physical solvent							
Location of CO_2 capture	Blast furnace gas	Fired heaters and H_2 plant	Fired heaters and H_2 plant		Boiler	IGCC	Fermentation and bagasse boiler	MEA Baseline (post-comb.)	MEA Baseline (post-comb.)	Membrane Water Gas Shift (pre-comb.)	Flue Gas Recycle & ITM (oxy-fuel)	Very Large-scale ATR (pre-comb.)	Sorption Enhanced Water Gas Shift (pre-comb.)
Capture unit size (specify units)					392 MW fuel	338 MW fuel		1351 MWt	358 MWt	1351 MWt	1351 MWt	358 MWt	358 MWt
CO_2 capture system efficiency (%)	90	95	91		90	90	100/90						
Energy source(s) for capture (type +onsite or offsite)													
Are all energy-related CO_2 emissions included?								yes	yes	yes	yes	yes	yes
CO_2 emission rate after capture ($kgCO_2$ MWh^{-1})								0.09	0.19	0.09	0.05	0.10	0.14
CO_2 captured (Mt yr^{-1})	2.795	1.013	1.175	1.970	0.969	0.399	0.560						
CO_2 product pressure (MPa)	11.0	11.0	11.0	8.0	10.0	10.0	10.0						
CO_2 reduction per unit of product (%)								60.3	76.5	58.4	75.8	87.4	82.2
Cost Results													
Cost year basis (constant dollars)													
Fixed charge factor (%)					15	15	15	11.0	11.0	11.0	11.0	11.0	11.0
Ref. plant capital cost (US$ per unit capacity)													
Capture plant capital cost (US$ per unit capacity)													
Incremental capital cost (million US\$ per kg s^{-1} CO_2)*	3.8	4.1	4.9	0.3	3.2	1.9	2.6						
Ref. plant cost of product (US$/unit)													
Capture plant cost of product (US$/unit)								10.2	55.1	6.1	6.8	54.2	48.2
Incremental cost of product (US$/unit)								10.2	55.1	6.1	6.8	54.2	48.2
% increase in capital cost (over ref. plant)													
% increase in unit cost of product (over ref. plant)													
Cost of CO_2 captured (US\$/tCO_2)		50	60					55.3	90.9	36.4	38.2	59.0	60.5
Cost of CO_2 avoided (US\$/tCO_2)	35	74	116	10	34	23	53	78.1	88.2	48.1	41.0	76.0	71.8
Capture cost confidence level (see Table 3.6)	moderate									low			

Notes: All costs in this table are for capture only and do not include the costs of CO_2 transport and storage; see Chapter 8 for total CCS costs. *Capital costs are incremental costs of capture, excluding cost of make-up steam and power generation and also excluding interest during construction and other owner's costs.

plants.

CO_2 could be captured at steam-generating plants or power plants that use other biomass byproducts and/or purpose-grown biomass. At present most biomass plants are relatively small. The cost of capturing 0.19 $MtCO_2$ yr^{-1} in a 24 MW biomass-powered IGCC plant, compared to a biomass IGCC plant without capture, is estimated to be about 70 US\$/tCO_2 (Audus and Freund, 2005). Larger plants using purpose-grown biomass may be built in the future and biomass can be co-fired with fossil fuels to give economies of scale, as discussed in Chapter 2. Biomass fuels produce similar or slightly greater quantities of CO_2 per unit of fuel energy as bituminous coals; thus, the CO_2 concentration of flue gases from these fuels will be broadly similar. This implies that the cost of capturing CO_2 at large power plants using biomass may be broadly similar to the cost of capturing CO_2 in large fossil fuel power plants in cases where plant size, efficiency, load factor and other key parameters are similar. The costs of avoiding CO_2 emissions in power plants that use biomass are discussed in more detail in Chapter 8.

3.7.9 Outlook for future CO_2 capture costs

The following sections focus on 'advanced' technologies that are not yet commercial available, but which promise to lower CO_2 capture costs based on preliminary data and design studies. Earlier sections of Chapter 3 discussed some of the efforts underway worldwide to develop lower-cost options for CO_2 capture. Some of these developments are based on new process concepts, while others represent improvements to current commercial processes. Indeed, the history of technology innovation indicates that incremental technological change, sustained over many years (often decades), is often the most successful path to substantial long-term improvements in performance and reductions in cost of a technology (Alic *et al.*, 2003). Such trends are commonly represented and quantified in the form of a 'learning curve' or 'experience curve' showing cost reductions as a function of the cumulative adoption of a particular technology (McDonald and Schrattenholzer, 2001). One recent study relevant to CO_2 capture systems found that over the past 25 years, capital costs for sulphur dioxide (SO_2) and nitrogen oxides (NO_x) capture systems at US coal-fired power plants have decreased by an average of 12% for each doubling of installed worldwide capacity (a surrogate for cumulative experience, including investments in R&D) (Rubin *et al.*, 2004a). These capture technologies bear a number of similarities to current systems for CO_2 capture. Another recent study (IEA, 2004) suggests a 20% cost reduction for a doubling of the unit capacity of engineered processes due to technological learning. For CCS systems the importance of costs related to energy requirements is emphasized, since reductions in such costs are required to significantly reduce the overall cost of CO_2 capture.

At the same time, a large body of literature on technology innovation also teaches us that learning rates are highly uncertain,[11] and that cost estimates for technologies at the early stages of development are often unreliable and overly optimistic (Merrow *et al.*, 1981). Qualitative descriptions of cost trends for advanced technologies and energy systems typically show costs increasing from the research stage through full-scale demonstration; only after one or more full-scale commercial plants are deployed do costs begin to decline for subsequent units (EPRI, 1993; NRC, 2003). Case studies of the SO_2 and NO_x capture systems noted above showed similar behaviour, with large (factor of two or more) increases in the cost of early full-scale FGD and SCR installations before costs subsequently declined (Rubin *et al.*, 2004b). Thus, cost estimates for CO_2 capture systems should be viewed in the context of their current stage of development. Here we try to provide a perspective on potential future costs that combines qualitative judgments with the quantitative cost estimates offered by technology developers and analysts. The sections below revisit the areas of power generation and other industrial processes to highlight some of the major prospects for CO_2 capture cost reductions.

3.7.10 CO_2 capture costs for electric power plants (advanced technology)

This section first examines oxy-fuel combustion, which avoids the need for CO_2 capture by producing a concentrated CO_2 stream for delivery to a transport and storage system. Following this we examine potential advances in post-combustion and pre-combustion capture.

3.7.10.1 Oxy-fuel combustion systems

It is first important to distinguish between two types of oxy-fuel systems: an oxy-fuel boiler (either a retrofit or new design) and oxy-fuel combustion-based gas turbine cycles. The former are close to demonstration at a commercial scale, while the latter (such as chemical looping combustion systems and novel power cycles using CO_2/water as working fluid) are still at the design stage. Table 3.13 summarizes the key assumptions and cost results of several recent studies of CO_2 capture costs for oxy-fuel combustion systems applied to new or existing coal-fired units. As discussed earlier in Section 3.4, oxygen combustion produces a flue gas stream consisting primarily of CO_2 and water vapour, along with smaller amounts of SO_2, nitrogen and other trace impurities. These designs eliminate the capital and operating costs of a post-combustion CO_2 capture system, but new costs are incurred for the oxygen plant and other system design modifications. Because oxy-fuel combustion is still under development and has not yet been utilized or demonstrated for large-scale power generation, the design basis and cost estimates for such systems remain highly variable and uncertain. This is reflected in the wide range of oxy-fuel cost estimates in Table 3.13. Note, however, that cost estimates for advanced design

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[11] In their study of 42 energy-related technologies, McDonald and Schrattenholzer (2001) found learning rates varying from -14% to 34%, with a median value of 16%. These rates represent the average reduction in cost for each doubling of installed capacity. A negative learning rate indicates that costs increased rather than decreased over the period studied.

Table 3.13 Capture costs: Advanced technologies for electric power plants. (continued on next page)

	OXY-FUEL COMBUSTION							ADVANCED PC	
Study Assumptions and Results	**Alstom** *et al.*	**Singh** *et al.*	**Stobbs &Clark**	**Dillon** *et al.*	**Nsakala** *et al.*	**Nsakala** *et al.*	**Nsakala** *et al.*	**Gibbins** *et al.*	**Gibbins** *et al.*
	2001	**2003**	**2005**	**2005**	**2003**	**2003**	**2003**	**2005**	**2005**
Reference Plant (without capture)	*				*	*	*		
Power plant type	RETROFIT subcrit PC	RETROFIT PC + aux NGCC	RETROFIT PC	New PC	Air-fired CFB	Air-fired CFB	Air-fired CFB	Double reheat supercrit PC	Double reheat supercrit PC
Fuel type (bit, sub-bit, lig; NG, other) and %S	bit, 2.7%S	sub-bit	lignite	bit	bit, 2.3%S	bit, 2.3%S	bit, 2.3%S		
Reference plant net size (MW)	434	400	300	677	193	193	193		
Plant capacity factor (%)	67	91		85	80	80	80	85	85
Net plant efficiency, LHV (%)				44.2	37.0	37.0	37.0	45.6	45.6
Fuel cost, LHV (US\$ GJ^{-1})	1.30			1.50	1.23	1.23	1.23	1.50	1.50
Reference plant emission rate (tCO_2 MWh^{-1})	0.908	0.925	0.883	0.722	0.909	0.909	0.909		
Capture Plant Design									
CO_2 capture technology	oxy-fuel	oxy-fuel	oxy-fuel	oxy-fuel	oxy-fuel	oxy-fuel with CMB	chemical looping with CMB	MEA	KS-1
Net plant size with capture (MW)	273	400		532	135	197	165		
Net plant efficiency, LHV (%)	23.4			35.4	25.8	31.3	32.2	34.3	36.5
CO_2 capture system efficiency (%)				about 91					
CO_2 emission rate after capture (t MWh^{-1})		0.238	0.145	0.085	0.086	0.073	0.005		
CO_2 captured (Mt yr^{-1})		2.664							
CO_2 product pressure (MPa)	13.9	15	13.7	11				11.0	11.0
CCS energy requirement (% more input MWh^{-1})				25	43	18	15	33	25
CO_2 reduction per kWh (%)		**74**		**88.2**	**90.5**	**92.0**	**99.5**		
Cost Results	**	**							
Cost year basis (constant dollars)		2001	2000		2003	2003	2003		
Fixed charge factor (%)	13.0	9.4		11				11.0	11.0
Reference plant TCR (US\$ kW^{-1})		0		1260	1500	1500	1500	1022	1022
Capture plant TCR (US\$ kW^{-1})	1527	909	4570	1857	2853	2731	1912	1784	1678
Incremental TCR for capture (US\$ kW^{-1})	1198	909		597	1354	1232	413	762	656
Reference plant COE (US\$ MWh^{-1})			**44.5**	**44**	**45.3**	**45.3**	**45.3**	**37**	**37**
Capture plant COE (US\$ MWh^{-1})			**97.5**	**61.2**	**82.5**	**70.5**	**58.4**	**61**	**57**
Incremental COE for capture (US\$ MWh^{-1})	44.5	23.9	53	17.2	37.2	25.2	13.1	24	20
% increase in capital cost (over ref. plant)				47	90	82	28	75	64
% increase in COE (over ref. plant)			**119**	**39**	**82**	**56**	**29**	**65**	**54**
Cost of CO_2 captured (US\$/tCO_2)		29							
Cost of CO_2 avoided (US\$/tCO_2)	54	35	72	27	45	30	14		
Capture cost confidence level (see Table 3.6)	low					very low	very low	low to moderate	

Notes: All costs in this table are for capture only and do not include the costs of CO_2 transport and storage; see Chapter 8 for total CCS costs. * Reported HHV values converted to LHV assuming LHV/HHV = 0.96 for coal. ** Reported value increased by 15% to estimate interest during construction and other owners' costs.

Table 3.13 *Continued.*

Study Assumptions and Results	ADVANCED NGCC								ADVANCED IGCC					ADVANCED HYBRIDS	
	Simbeck	**Parsons**	**Parsons**	**CCP**	**CCP**	**CCP**	**CCP**	**Dillon *et al.***	**Parsons**	**NETL**	**NETL**	**CCP**	**CCP**	**NETL**	**Parsons**
	2002	**2002b**	**2002b**	**2005**	**2005**	**2005**	**2005**	**2005**	**2002b**	**2002**	**2002**	**2005**	**2005**	**2002**	**2002b**
Reference Plant (without capture)									*	*	*			*	
Power plant type	comb. cycle H-class turbine	comb. cycle H-class turbine	comb. cycle H-class turbine					NGCC	E-gas, O_2, water scrubber; H-class turbine	E-gas, O_2, CGCU, Hydraulic air compression	E-gas, O_2, CGCU, Hydraulic air compression with open loop water system	Canada coke gasification	Canada coke gasification	E-gas, O_2, HGCU, "G" GT, SOFC /	CHAT SOFC
Fuel type (bit, sub-bit, lig; NG, other) and %S	Nat. gas	Nat. gas	Nat. gas	NG	NG	NG	NG	NG	Illinois #6	Illinois #6	Illinois #6	Coke	Coke	Illinois #6	Nat. gas
Reference plant net size (MW)	480	384	384	392	392	392	507	388	425	326	408	588	588	644	557
Plant capacity factor (%)	80	65	80	95	95	95	95	85	80	85	85	91.3	91.3	85	80
Net plant efficiency, LHV (%)	60.0	59.5	59.5	57.6%	57.6%	57.6%	57.6%	56.0	41.1	43.8	54.9			56.4	66.2
Fuel cost, LHV (US\$ GJ^{-1})	4.86	2.82	2.82	2.96	2.96	2.96	2.96	3.00	1.23	1.03	1.03	2.96	2.96	1.03	2.82
Reference plant emission rate (tCO_2 MWh^{-1})	0.342	0.338	0.338	0.37	0.37	0.37	0.37	0.371	0.720	0.712	0.568	0.95	0.95	0.572	0.302
Capture Plant Design															
CO_2 capture technology	MEA	MEA	MEA	MEA low-cost/ CCGT-integrated (post-comb.)	Membrane Contactor; KS-1 (post-comb.)	Hydrogen Membrane Reformer (pre-comb.)	Sorption Enhanced Water Gas Shift- Air ATR (pre-comb.)	Oxy-fuel	Selexol	Selexol		IGCC with capture (pre-comb.)	IGCC with advanced capture (pre-comb.)	Selexol	
Net plant size with capture (MW)	413	311	311	345	335	361	424	440	387	312	404	699	734	755	517
Net plant efficiency, LHV (%)	51.7	48.1	48.1	50.6	49.2	53.0	48.2	44.7	33.8	35.2	45.4			49.7	46.1
CO_2 capture system efficiency (%)	85	90	90	86	86	100	90		91.5	92.7	92.7			90	86.8
CO_2 emission rate after capture (t/MWh)	0.06	0.042	0.042	0.06	0.06	0.00	0.04	0.011	0.074	0.065	0.050	0.27	0.28	0.046	0.043
CO_2 captured (Mt yr−1)	0.980	0.669	0.823	1.09	1.09	1.27	1.47		2.074	1.984	1.984	6.80	6.44	3.390	
CO_2 product pressure (MPa)	13.7	8.3	8.3					11	8.3	14.5	14.5			14.5	8.3
CCS energy requirement(% more input MWh−1)	16	24	24					25	22	24	21			13	44
CO_2 reduction per kWh (%)	82	88	88	84.1	83.6	100	87.9	97.0	90	91	91	71.2	71.1	92	86
Cost Results															
Cost year basis (constant dollars)	2001	2000	2000						2000	2002	2002			2002	2000
Fixed charge factor (%)	15.0			11.0	11.0	11.0	11.0	11	15.0	14.8	14.8	11.0	11.0	14.8	
Reference plant TCR (US\$ kW^{-1})	582	539	496	724	724	724	724	559	1249	1436	881.4	1398	1398	1508	623
Capture plant TCR (US\$ kW^{-1})	1216	1026	943	1002	1225	1058	1089	1034	1698	2189	1450	1919	1823	1822	
Incremental TCR for capture (US\$ kW^{-1})	634	487	447	278	501	334	365	475	449	753	568	521	425	314	
Reference plant COE (US\$ MWh^{-1})	42.9	33.5	30.7	34.2	34.2	34.2	34.2	33.5	41.0	47.0	28.5	32.3	32.3	41.1	
Capture plant COE (US\$ MWh^{-1})	65.9	54.1	48.8	45.1	48.9	43.2	45.4	50.3	53.6	65.5	41.8	42.1	40.5	48.8	
Incremental COE for capture (US\$ MWh^{-1})	23	20.6	18.1	10.9	14.7	9.0	11.2	16.8	12.6	18.5	13.3	9.8	8.2	7.7	
% increase in capital cost (over ref. plant)	109	90	90	38	69	46	50	85	36	52	64	37	30	21	
% increase in COE (over ref. plant)	54	61	59	32	43	26	33	50	31	39	47	30	25	19	
Cost of CO_2 captured (US\$/tCO_2)		48		30.2	39.5	22.5	28.2		16	22	20	11	10	13	
Cost of CO_2 avoided (US\$/tCO_2)	82	70	61	35.1	47.5	24.4	34.4	47	19	29	26	14	12	15	
Capture cost confidence level (see Table 3.6)	low to moderate				low to very low				low					very low	

Notes: All costs in this table are for capture only and do not include the costs of CO_2 transport and storage; see Chapter 8 for total CCS costs. * Reported HHV values converted to LHV assuming LHV/HHV = 0.96 for coal and LHV/HHV = 0.90 for natural gas. **Reported value increased by 15% to estimate interest during construction and other owners' costs.

concepts based on oxy-fuel combustion gas turbine cycles are more uncertain at this time than cost estimates for new or retrofitted boilers employing oxy-fuel combustion.

For new plant applications, the data in Table 3.13 indicate that oxy-fuel combustion adds about 30-90% to the capital cost and 30-150% to the COE of a conventional plant, while reducing CO_2 emissions per kWh by 75-100%. Retrofit applications exhibit higher relative costs in cases where the existing plant is wholly or partially amortized. The lowest-cost oxy-fuel system in Table 3.13 is one that employs chemical looping to achieve nearly a 100% reduction in CO_2 emissions. While this concept thus appears promising (see Section 3.4.6), it has yet to be tested and verified at a meaningful scale. Thus cost estimates based on conceptual designs remain highly uncertain at this time.

To judge the potential cost savings of oxy-fuels relative to current CO_2 capture systems, it is useful to compare the costs of alternative technologies evaluated within a particular study based on a particular set of premises. In this regard, the COE for the oxy-fuel retrofit system reported by Alstom *et al.* (2001) in Table 3.13 is 20% lower than the cost of an amine system retrofit (Table 3.13) for the same 255 MW plant, while the cost of CO_2 avoided is 26% lower. In contrast, a recent study by the Canadian Clean Power Coalition (Stobbs and Clark, 2005) reports that the COE for an oxy-fuel system at a large lignite-fired plant (Table 3.13) is 36% higher than for an amine CO_2 capture system, while the cost of CO_2 avoided is more than twice as great. The major source of that cost difference was a specification in the CCPC study that the oxy-fuelled unit also be capable of full air firing. This resulted in a much higher capital cost than for a new unit designed solely for oxy-fuel operation. A more recent study sponsored by IEA GHG (Dillon *et al.*, 2005) found that a large new supercritical coal-fired boiler with oxy-fuel combustion had a COE slightly (2-3%) lower than a state-of-the-art coal plant with post-combustion analyzed in a separate study employing similar assumptions (IEA GHG, 2004). Further cost reductions could be achieved with the successful development of new lower-cost oxygen production technology (see Section 3.4.5). At the current time, the optimum designs of oxy-fuel combustion systems are not yet well established and costs of proposed commercial designs remain uncertain. This is especially true for advanced design concepts that employ components which are not yet available or still in the development stage, such as CO_2 gas turbines or high temperature ceramic membranes for oxygen production.

3.7.10.2 Advanced systems with post-combustion capture

Improvements to current amine-based systems for post-combustion CO_2 capture are being pursued by a number of process developers (Mimura *et al.*, 2003; Muramatsu and Iijima, 2003; Reddy *et al.*, 2003) and may offer the nearest-term potential for cost reductions over the systems currently in use. The newest systems summarized earlier in Table 3.7 reportedly reduce the cost of CO_2 avoided by approximately 20-30% (IEA GHG, 2004). Table 3.13 indicates that additional advances in plant heat integration could further reduce the COE of capture plants by about 5%. These results are consistent with a recent study by Rao *et al.* (2003), who used expert elicitations and a plant simulation model to quantify the improvements likely achievable by 2015 for four key process parameters: sorbent concentration, regeneration energy requirements, sorbent loss and sorbent cost. The 'most likely' improvement was an 18% reduction in COE, while the 'optimistic' estimates yielded a 36% cost reduction from improvements in just these four parameters. The cost of CO_2 avoided was reduced by similar amounts. Advances in more efficient heat integration (for sorbent regeneration) and higher power plant efficiency could lead to even greater reductions in CO_2 capture cost.

Advances in gas turbine technology produce similar benefits for NGCC systems. Table 3.13 shows several cases based on the H-turbine design. Relative to the cases in Table 3.9, these systems offer higher efficiency and greater CO_2 reductions per kWh. The higher COEs for the advanced NGCC systems reflects the higher natural gas prices assumed in more recent studies.

Table 3.13 indicates that other advanced technologies for post-combustion applications, such as membrane separation systems, may also lower the future cost of CO_2 capture (see Section 3.3.3). Reliable cost estimates for such technologies should await their further development and demonstration.

3.7.10.3 Advanced systems with pre-combustion capture

The cost of gasification-based systems with CO_2 capture also can be expected to fall as a result of continued improvements in gas turbine technology, gasifier designs, oxygen production systems, carbon capture technology, energy management and optimization of the overall facility. One recent study (IEA GHG, 2003) estimates a 20% reduction in the cost of electricity generation from a coal-based IGCC plant with CO_2 capture by 2020. This takes into account improvements in gasification, oxygen production, physical solvent scrubbing and combined cycle processes, but does not take into account any possible radical innovations in CO_2 separation technology. The additional IGCC cases shown in Table 3.13, including recent results of the CO_2 Capture Project (CCP, 2005), foresee similar reductions in the COE of advanced IGCC systems compared to the systems in Table 3.10.

3.7.11 CO_2 capture costs for hydrogen production and multi-product plants (advanced technology)

Table 3.14 shows results of several recent studies that have projected the performance and cost of new or improved ways of producing hydrogen and electricity from fossil fuels.

Compared to the current commercial plants in Table 3.11, the advanced single-product systems with CO_2 capture have hydrogen cost reductions of 16% (for natural gas feedstock) to 26% (for coal feedstock). Additional cases in Table 3.14 show multi-product systems producing hydrogen and electricity. These cases indicate the potential for substantial reductions in the future cost of hydrogen production with CO_2 capture. As before, the results are sensitive to the assumed selling price of co-product electricity. More importantly, these cases assume

Table 3.14 CO_2 capture costs: Multi-product plants using advanced technology.

Study Assumptions and Results	Simbeck	NRC	NRC	Parsons	Mitretek	Mitretek	Mitretek	Range	
	2005	2004	2004	2002a	2003	2003	2003	min	max
Capture Plant Design	*			*	*	*	*		
Plant products (primary/secondary)	H_2	H_2	H_2	H_2+electricity	H_2+electricity	H_2+electricity	H_2+electricity		
Production process or type	Autothermal reforming with O_2 provided by ITM	78% efficient ATR/SMR, adv CO_2 compressor	Gasifier LHV= 75-->80%, Adv ASU, membrane sep, adv CO_2 compressor	High-pressure E-gas, HGCU, HTMR, H_2SO_4 co-product	Advanced E-gas, HGCU, HTMR	Advanced E-gas, HGCU, HTMR, large elec. co-product	Advanced E-gas, HGCU, HTMR, SOFC, large elec. co-product		
Feedstock	Natural gas	Natural gas	Coal	Pgh #8 Coal	Coal	Coal	Coal		
Feedstock cost, LHV (US$ GJ^{-1})	5.26	4.73	1.20	0.89	1.03	1.03	1.03	1	5
Plant capacity factor (%)	90	90	90	80	85	85	85	80	90
CO_2 capture/separation technology	Oxy-fuel			Oxy-fuel	Oxy-fuel	Oxy-fuel	Oxy-fuel		
Capture plant input capacity, LHV (GJ h^{-1})	9527	7697	8121	2794	3020	6051	6051	2794	9527
Capture plant output capacity: LHV: Fuels (GJ h^{-1})	7504	6004	6004	1956	1904	1844	1808	1808	7504
Electricity (MW)	–13	–66	–88	7	25	416	519	-88	519
Net plant efficiency, LHV (%)	78.3	74.9	70.0	70.9	66.0	55.2	60.7	55	78
CO_2 capture efficiency (%)**	95	90	90	94	100	100	95	90	100
CO_2 emitted ($MtCO_2$ yr^{-1})***	0.086	0.505	0.873	0.117	0.000	0.000	0.191	0.000	0.873
Carbon exported in fuels (MtC yr^{-1})	0	0	0	0	0	0	0	0	0
Total carbon released ($kgCO_2$ GJ^{-1} products)	1.46	11.10	19.45	8.45	0.00	0.00	6.96	0.0	19.5
CO_2 captured ($MtCO_2$ yr^{-1})	4.074	3.119	5.853	1.855	1.918	3.846	3.652	1.9	5.9
CO_2 product pressure (MPa)	13.7	13.7	13.7	13.4	20	20	20	13.4	20.0
Cost Results									
Cost year basis (constant dollars)	2003	2000	2000	2000	2000	2000	2000		
Fixed charge rate (%)	20	16	16	14.3	12.7	12.7	12.7	12.7	20.0
Capture plant TCR (million US$)****	725	441	921	398	441	950	1023	398	1023
Capture plant electricity price (US$ MWh^{-1})	50.0	45.0	45.0	30.8	53.6	53.6	53.6	31	54
Capture plant fuel product cost, LHV (US$ GJ^{-1})	9.84	8.53	6.39	5.79	6.24	3.27	1.13	1.13	9.84
Capture cost confidence level (see Table 3.6)	low	low	low	low to very low			very low		

Notes: All costs in this table are for capture only and do not include the costs of CO_2 transport and storage; see Chapter 8 for total CCS costs. * Reported HHV values converted to LHV assuming LHV/HHV = 0.96 for coal and 0.846 for hydrogen. **CO_2 capture efficiency = (C in CO_2 captured)/(C in fossil fuel input to plant - C in carbonaceous fuel products of plant) x100; C associated with imported electricity is not included. ***Includes CO_2 emitted in the production of electricity imported by the plant. ****Reported total plant investment values increased by 3.5% to estimate total capital requirement.

the successful scale-up and commercialization of technologies that have not yet been demonstrated, or which are still under development at relatively small scales, such as solid oxide fuel cells (SOFC). Published cost estimates for these systems thus have a very high degree of uncertainty.

3.7.12 CO_2 capture costs for other industrial processes (advanced technology)

As noted earlier, CO_2 capture for industrial processes has not been widely studied. The most extensive analyses have focused on petroleum refineries, especially CO_2 capture options for heaters and other combustion-based processes (see Table 3.12). The use of oxy-fuel combustion offers potential cost savings in several industrial applications. The CO_2 Capture Project reports the cost of capturing CO_2 in refinery heaters and boilers, with an ion transport membrane oxygen plant, to be 31 US\$/tCO_2 avoided. The cost of pre-combustion capture based on shift and membrane gas separation was predicted to be 41 US\$/tCO_2 avoided (CCP, 2005).

It also may be possible to apply oxy-fuel combustion to cement plants, but the CO_2 partial pressure in the cement kiln would be higher than normal and the effects of this on the calcination reactions and the quality of the cement product would need to be investigated. The quantity of oxygen required per tonne of CO_2 captured in a cement plant would be only about half as much as in a power plant, because only about half of the CO_2 is produced by fuel combustion. This implies that the cost of CO_2 capture by oxy-fuel combustion at large cement plants would be lower than at power plants, but a detailed engineering cost study is lacking. Emerging technologies that capture CO_2 using calcium-based sorbents, described in Section 3.3.3.4, may be cost competitive in cement plants in the future.

3.7.13 Summary of CO_2 capture cost estimates

Table 3.15 summarizes the range of current CO_2 capture costs for the major electric power systems analyzed in this report. These costs apply to case studies of large new plants employing current commercial technologies. For the PC and IGCC systems, the data in Table 3.15 apply only to plants using bituminous coals and the PC plants are for supercritical units only. The cost ranges for each of the three systems reflect differences in the technical, economic and operating assumptions employed in different studies. While some differences in reported costs can be attributed to differences in the CO_2 capture system design, the major sources of variability are differences in the assumed design, operation and financing of the reference plant to which the capture technology is applied (i.e., factors such as plant size, location, efficiency, fuel type, fuel cost, capacity factor and cost of capital). Because no single set of assumptions applies to all situations or all parts of the world, we display the ranges of cost represented by the studies in Tables 3.8, 3.10, 3.11 and 3.12.

For the power plant studies reflected in Table 3.15, current CO_2 capture systems reduce CO_2 emissions per kilowatt-hour by approximately 85-90% relative to a similar plant without capture. The cost of electricity production attributed to CO_2 capture increases by 35-70% for a natural gas combined cycle plant, 40-85% for a new pulverized coal plant and 20-55% for an integrated gasification combined cycle plant. Overall, the COE for fossil fuel plants with capture ranges from 43-86 US\$ MWh^{-1}, as compared to 31-61 US\$ MWh^{-1} for similar plants without capture. These costs include CO_2 compression but not transport and storage costs. In most studies to date, NGCC systems typically have a lower COE than new PC and IGCC plants (with or without capture) for large base load plants with high capacity factors (75% or more) and gas prices below about 4 US\$ GJ^{-1} over the life of the plant. However, for higher gas prices and/or lower capacity factors, NGCC plants typically have higher COEs than coal-based plants, with or without capture. Recent studies also found that IGCC plants were on average slightly more costly without capture and slightly less costly with capture than similarly sized PC plants. However, the difference in cost between PC and IGCC plants with or without CO_2 capture can vary significantly with coal type and other local factors, such as the cost of capital. Since neither PC nor IGCC systems have yet been demonstrated with CO_2 capture and storage for a large modern power plant (e.g., 500 MW), neither the absolute or relative costs of these systems (nor comparably sized NGCC systems with capture and storage) can be stated with a high degree of confidence at this time, based on the criteria of Table 3.6.

Table 3.15 also shows that the lowest CO_2 capture costs with current technology (as low as 2 US\$/tCO_2 captured or avoided) were found for industrial processes such as coal-based hydrogen production plants that produce concentrated CO_2 streams as part of the production process. Such industrial processes may represent some of the earliest opportunities for CCS.

Figure 3.20 displays the normalized power plant cost and emissions data from Table 3.15 in graphical form. On this graph, the cost of CO_2 avoided corresponds to the slope of a line connecting any two plants (or points) of interest. While Table 3.15 compares a given capture plant to a similar plant without capture, in some cases comparisons may be sought between a given capture plant and a different type of reference plant. Several cases are illustrated in Figure 3.20 based on either a PC or NGCC reference plant. In each case, the COE and CO_2 emission rate are highly dependent upon technical, economic and financial factors related to the design and operation of the power systems of interest at a particular location. The cost of CO_2 avoided is especially sensitive to these site-specific factors and can vary by an order of magnitude or more when different types of plants are compared. Comparisons of different plant types, therefore, require a specific context and geographical location to be meaningful and should be based on the full COE including CO_2 transport and storage costs. Later, Chapter 8 presents examples of full CCS costs for different plant types and storage options.

In contrast to new plants, CO_2 capture options and costs for existing power plants have not been extensively studied. Current studies indicate that these costs are extremely site-specific and fall into two categories (see Table 3.8). One is the retrofitting of a post-combustion capture system to the existing unit.

Table 3.15 Summary of new plant performance and CO$_2$ capture cost based on current technology.

Performance and Cost Measures	New NGCC Plant		New PC Plant		New IGCC Plant		New Hydrogen Plant		(Units for H$_2$ Plant)
	Range	*Rep.*	Range	*Rep.*	Range	*Rep.*	Range	*Rep.*	
	low high	*Value*	low high	*Value*	low high	*Value*	low high	*Value*	
Emission rate without capture (kgCO$_2$ MWh^{-1})	344 - 379	*367*	736 - 811	*762*	682 - 846	*773*	78 - 174	*137*	kgCO$_2$ GJ^{-1} (without capture)
Emission rate with capture (kgCO$_2$ MWh^{-1})	40 - 66	52	92 - 145	*112*	65 - 152	*108*	7 - 28	*17*	kgCO$_2$ GJ^{-1} (with capture)
Percent CO$_2$ reduction per kWh (%)	83 - 88	*86*	81 - 88	*85*	81 - 91	*86*	72 - 96	*86*	% reduction/unit of product
Plant efficiency with capture, LHV basis (%)	47 - 50	*48*	30 - 35	*33*	31 - 40	*35*	52 - 68	*60*	Capture plant efficiency (% LHV)
Capture energy requirement (% more input MWh^{-1})	11 - 22	*16*	24 - 40	*31*	14 - 25	*19*	4 - 22	*8*	% more energy input GJ^{-1} product
Total capital requirement without capture (US$ kW^{-1})	515 - 724	*568*	1161 - 1486	*1286*	1169 - 1565	*1326*	*(No unique normalization for multi-product plants)*		Capital requirement without capture
Total capital requirement with capture (US$ kW^{-1})	909 - 1261	*998*	1894 - 2578	*2096*	1414 - 2270	*1825*			Capital requirement with capture
Percent increase in capital cost with capture (%)	64 - 100	*76*	44 - 74	*63*	19 - 66	*37*	-2 - 54	*18*	% increase in capital cost
COE without capture (US$ MWh^{-1})	31 - 50	*37*	43 - 52	*46*	41 - 61	*47*	6.5 - 10.0	*7.8*	H$_2$ cost without capture (US$ GJ^{-1})
COE with capture only (US$ MWh^{-1})	43 - 72	*54*	62 - 86	*73*	54 - 79	*62*	7.5 - 13.3	*9.1*	H$_2$ cost with capture (US$ GJ^{-1})
Increase in COE with capture (US$ MWh^{-1})	12 - 24	*17*	18 - 34	*27*	9 - 22	*16*	0.3 - 3.3	*1.3*	Increase in H$_2$ cost (US$ GJ^{-1})
Percent increase in COE with capture (%)	37 - 69	*46*	42 - 66	*57*	20 - 55	*33*	5 - 33	*15*	% increase in H$_2$ cost
Cost of CO$_2$ captured (US$/tCO$_2$)	33 - 57	*44*	23 - 35	29	11 - 32	*20*	2 - 39	*12*	US$/tCO$_2$ captured
Cost of CO$_2$ avoided (US$/tCO$_2$)	37 - 74	*53*	29 - 51	*41*	13 - 37	23	2 - 56	*15*	US$/tCO$_2$ avoided
Capture cost confidence level (see Table 3.6)	moderate		moderate		moderate		moderate to high		Confidence Level (see Table 3.6)

Notes: See Section 3.6.1 for calculation of energy requirement for capture plants. Values in italics were adjusted from original reported values as explained below.(a) Ranges and representative values are based on data from Tables 3.8, 3.11, 3.11 and 3.12. All costs in this table are for capture only and do not include the costs of CO$_2$ transport and storage; see Chapter 8 for total CCS costs. (b) All PC and IGCC data are for bituminous coals only at costs of US$1.0-1.5 GJ^{-1} (LHV); all PC plants are supercritical units. (c) NGCC data based on natural gas prices of US$2.8-4.4 GJ^{-1} (LHV basis). (d) Cost are in constant US dollars (approx. year 2002 basis). (e) Power plant sizes range from approximately 400-800 MW without capture and 300-700 MW with capture. (f) Capacity factors vary from 65-85% for coal plants and 50-95% for gas plants (average for each = 80%). (g) Hydrogen plant feedstocks are natural gas (US$ 4.7-5.3 GJ^{-1}) or coal (US$ 0.9-1.3 GJ^{-1}); some plants in data set produce electricity in addition to hydrogen. (h) Fixed charge factors vary from 11-16% for power plants and 13-20% for hydrogen plants. (i) All costs include CO$_2$ compression but not additional CO$_2$ transport and storage costs (see Chapter 8 for full CCS costs).

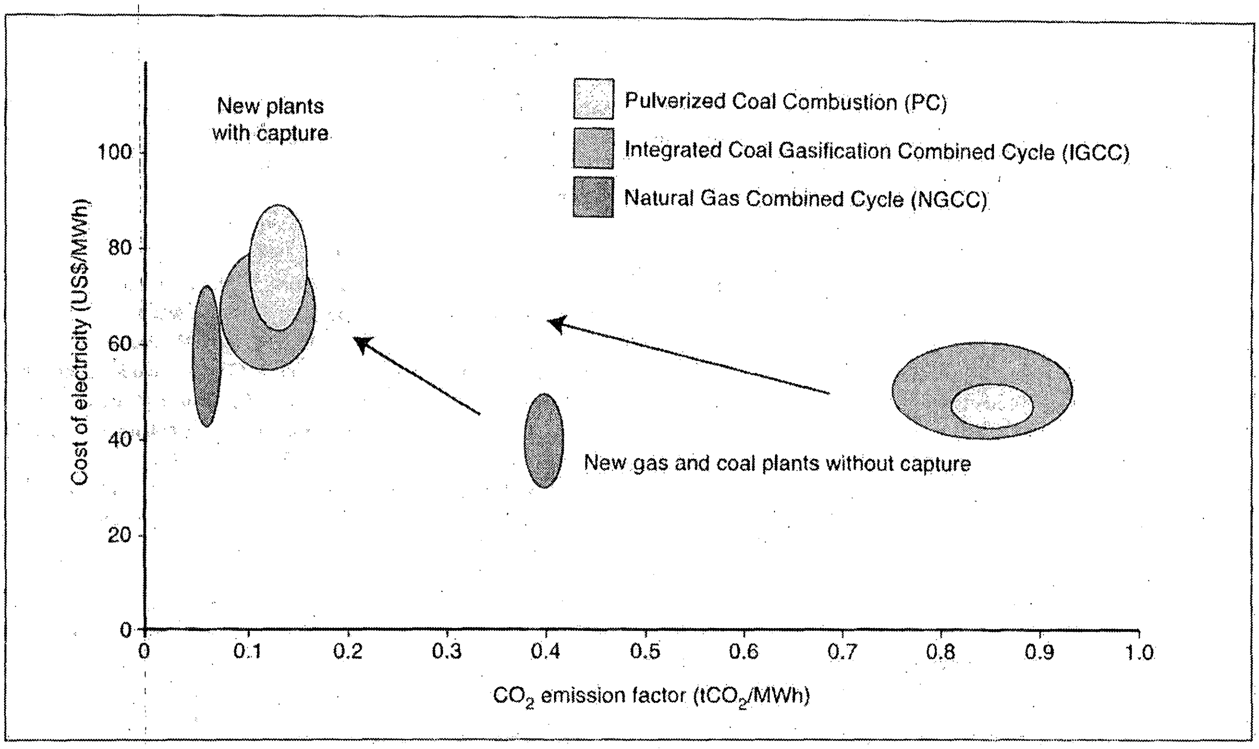

Figure 3.20 Cost of electricity (excluding transport and storage costs) compared to CO_2 emission rate for different reference and capture plants based on current technology. The shaded areas show the Table 3.15 ranges of CO_2 emission rates and levelized cost of electricity (COE) for new PC, IGCC and NGCC plants with and without CO_2 capture. All coal plant data are for bituminous coals only. PC plants are supercritical units only (see Tables 3.7, 3.9, 3.10 and 3.15 for additional assumptions). The cost of CO_2 avoided corresponds to the slope of a line connecting a plant with capture and a reference plant without capture (i.e., the change in electricity cost divided by the change in emission rate). Avoidance costs for the same type of plant with and without capture plant are given in Table 3.15. When comparing different plant types, the reference plant represents the least-cost plant that would 'normally' be built at a particular location in the absence of a carbon constraint. In many regions today, this would be either a PC plant or an NGCC plant. The cost per tonne of CO_2 avoided can be highly variable and depends strongly on the costs and emissions of new plants being considered in a particular situation. See Chapter 8 for the full COE and full cost of CO_2 avoided for different plant types.

The other category combines CO_2 capture with upgrading or repowering the existing plant to significantly improve its efficiency and net power output (see Sections 3.7.4.2 and 3.7.5.2). In general, the latter option appears to be more cost-effective. However, further site-specific studies are required to systematically assess the feasibility and cost of alternative repowering options in conjunction with CO_2 capture for existing power plants.

New or improved methods of CO_2 capture, combined with advanced power systems and industrial process designs, promise to significantly reduce CO_2 capture costs and associated energy requirements. Tables 3.12 to 3.14 summarize the results from recent studies that examine future options. As discussed earlier, there is considerable uncertainty about the magnitude and timing of future cost reductions, as well as the potential for costs to rise above current estimates, especially for technologies still in the early stages of research and development. The current assessment is based on studies of the specific technologies in Tables 3.12 to 3.14 (and the supporting discussions and literature cited in Sections 3.7.9 to 3.7.12), as well as analyses of historical cost trends for related energy and environmental technologies. This assessment suggests that improvements to current commercial technologies can reduce CO_2 capture costs by at least 20-30% over approximately the next decade, while new technologies under development promise more substantial cost reductions. Achieving future cost reductions, however, will require deployment and adoption of commercial technologies in the marketplace as well as sustained R&D.

3.8 Gaps in knowledge

Gaps in knowledge are related to differences in the stages of development of component technologies for the capture systems reviewed in Sections 3.2 to 3.5. For CO_2 capture from industrial processes, a number of technologies that are commonly used in natural gas sweetening and ammonia production are already used on a commercial scale. For other types of industrial systems capturing CO_2 from steel and cement production, further work is still needed. For CO_2 capture that might be reliant on post-combustion capture or oxy-fuel combustion, options are less well developed, or are available at a smaller scale than those required for applications such as in power generation, where much larger gas flows are handled. For pre-combustion capture many of the required systems have been developed and applied in industry already.

Although many of the component and/or enabling technologies required for CO_2 capture in post-combustion, pre-combustion and oxy-fuel combustion are well known, gaps in knowledge are in the practical and/or commercial demonstration of integrated systems. This demonstration is essential to prove the cost of CO_2 capture and its use on a large scale, particularly in power generation applications, but also for cement, steel and other large industries. Operating experience is also needed to test system reliability, improved methods of system integration, methods to reduce the energy requirements for CO_2 capture, improved process control strategies and the use of optimized functional materials for the implementation of capture processes with advanced, higher efficiency power cycles. As such developments are realized, environmental issues associated with the capture of CO_2 and other deleterious pollutants in these systems should also be re-assessed from a perspective involving the whole capture-transport-storage operation.

In an ongoing search to implement existing, new or improved methods of CO_2 capture, most capture systems also rely on the application of a range of enabling technologies that influence the attractiveness of a given system. These enabling technologies have their own critical gaps of knowledge. For example, improved processes for the effective removal of sulphur, nitrogen, chlorine, mercury and other pollutants are needed for the effective performance of unit operations for CO_2 separation in post- and pre-combustion capture systems, especially when coal is used as the primary fuel. Improved gasification reactors for coals and biomass, the availability of hydrogen-burning gas turbines and fuel cells for stationary power generation also need further development in the pre-combustion route. Combustors and boilers operating at higher temperatures, or a new class of CO_2 turbines and compressors, are important requirements for oxy-fuel systems.

With reference to the development of novel CO_2 capture and/or other enabling technologies, a wide range of options are currently being investigated worldwide. However, many technical details of the specific processes proposed or under development for these emerging technologies are still not well understood. This makes the assessment of their performance and cost highly uncertain. This is where intense R&D is needed to develop and bring to pilot scale testing the most promising concepts for commercial application. Membranes for H_2, CO_2 or O_2 separation, new sorbents, O_2 or CO_2 solid carriers and materials for advanced combustors, boilers and turbines all require extensive performance testing. Multi-pollutant emission controls in these novel systems and the impact of fuel impurities and temperature on the functional materials, should also be an area of future work.

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Attachment 3

Comments of
Environmental Law & Policy Center, Sierra Club and Valley Watch Inc.

217/782-2113

CONSTRUCTION PERMIT - PSD APPROVAL
NSPS-NESHAP EMISSION UNITS

PERMITTEE

Indeck-Elwood LLC
Attn: Mr. James Schneider
600 N. Buffalo Grove Road
Buffalo Grove, Illinois 60089

Application No.: 02030060
Applicant's Designation:
Subject: Electricity Generation Facility
Date Issued: October 10, 2003
Location: Southwest of the Intersection of Drummond and Baseline Roads, Elwood, Will County

I.D. No.: 197035AAJ
Date Received: March 21, 2002

Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source and air pollution control equipment consisting of an electric power plant with two circulating fluidized bed boilers, fuel handling and storage, limestone handling and storage, ash handling and storage, cooling towers, auxiliary gas-fired boiler, and ancillary operations, as described in the above referenced application. This Permit is granted based upon and subject to the findings and conditions that follow.

In conjunction with this permit, approval is given with respect to the federal regulations for Prevention of Significant Deterioration of Air Quality (PSD) for the plant, as described in the application, in that the Illinois Environmental Protection Agency (IEPA) finds that the application fulfills all applicable requirements of 40 CFR 52.21. This approval is issued pursuant to the Clean Air Act, as amended, 42 U.S.C. 7401 et seq., the federal regulations promulgated thereunder at 40 CFR 52.21 for Prevention of Significant Deterioration of Air Quality (PSD), and a Delegation of Authority agreement between the United States Environmental Protection Agency (USEPA) and the Illinois EPA for the administration of the PSD Program. This approval becomes effective in accordance with the provisions of 40 CFR 124.15 and may be appealed in accordance with provisions of 40 CFR 124.19. This approval is based upon the findings that follow. This approval is subject to the following conditions. This approval is also subject to the general requirement that the plant be developed and operated consistent with the specifications and data included in the application and any significant departure from the terms expressed in the application, if not otherwise authorized by this permit, must receive prior written authorization from the Illinois EPA.

If you have any questions on this permit, please call Shashi Shah at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permit Section
Division of Air Pollution Control

DES:SRS:jar

cc: Region 1
USEPA Region V

UNIT-SPECIFIC CONDITION 2: CONDITIONS FOR BULK MATERIAL HANDLING OPERATIONS

2.1 Description of Emission Units

The affected units for the purpose of these unit-specific permit conditions are operations that handle materials in bulk that are involved with the operation of the power plant and have the potential for particulate matter emissions, including coal, petroleum coke, coal tailings, limestone, and ash. Affected units include receiving, transfer, handling, storage, processing or preparation (drying, crushing, etc.) and loading operations for such materials.

2.2 Control Technology Determination

a. i. Emissions of particulate matter from affected units, other than operations associated with material storage in building or associated with storage piles, shall be controlled with enclosures and aspiration to baghouses or other filtration devices designed to emit no more than 0.005 grains/dry standard cubic foot (gr/dscf). These devices shall be operated in accordance with good air pollution control practice to minimize emissions.

ii. There shall be no visible fugitive emissions, as defined by 40 CFR 60.671, from storage buildings.

iii. Storage piles shall be controlled by enclosure, material quality, temporary covers and application of water or other dust suppressants so as to minimize fugitive emissions to the extent practicable.

b. i. The only fuel burned in the limestone drying mills shall be natural gas, as defined by 40 CFR 60.41a.

ii. Emissions from each limestone drying mill attributable to combustion of fuel shall not exceed the following limits, except during startup and shutdown. These limits shall apply as a 3-hour block average, with compliance determined in accordance with Condition 2.8 and proper operation.

A. NO_x - 0.073 lb/million Btu.

B. CO - 0.20 lb/million Btu.

C. VOM - 0.02 lb/million Btu.

2.3 Applicable Federal Emission Standards

a. Affected units engaged in handling limestone shall comply with applicable requirements of the NSPS for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subpart OOO and related provisions of 40 CFR 60, Subpart A.

i. Pursuant to the NSPS, stack emissions of particulate matter are subject to the following limitations:

A. The rate of emissions shall not exceed 0.05 gram/dscm (0.02 g/dscf) (40 CFR 60.672(a)(1))*

Commonwealth of Kentucky

Division for Air Quality

RESPONSE TO COMMENTS

ON THE TITLE V DRAFT PERMIT V-07-017

Cash Creek Generation, LLC.

Cash Creek Generating Station

Henderson, KY

November 28, 2007

Combustion Section, Reviewer

SOURCE ID: 21-101-00134
AGENCY INTEREST: 40285
ACTIVITY: APE20060001

SOURCE DESCRIPTION:

Cash Creek Generation, LLC, has applied to the Kentucky Division for Air Quality for a Title V permit to construct a nominal 770 megawatt (MW) electric generation station to be located at Kentucky State Highway 1078 in Henderson, Kentucky. The IGCC facility, an air separation plant, a coal gasification facility and a combined cycle power generation facility are integrated into a single efficient electric generation station to produce electricity from synthesis gas (syngas). The syngas will be the primary fuel used to fire two, GE7FB series combustion turbines (CT's) in combination with two heat recovery steam generating (HRSG) units and a steam turbine to produce electricity. For the IGCC combustion turbines, SCR and nitrogen diluent to control NO_x emissions has been included. Additional associated equipment are the tail gas thermal oxidizer, gasifier flare, the associated material storage and handling processes (coal, and combustion by-products), the cooling tower, the auxiliary boiler, and the emergency fire water pump.

The proposed project is classified as a Title V major source due to its emissions of regulated air pollutants. It constitutes a major stationary source as defined in 401 KAR 51:017, Prevention of Significant Deterioration of Air Quality and is subject to evaluation and review under the provisions of the PSD regulation. The proposed project will result in a significant emissions increases of the following regulated air pollutants: Particulate matter (PM & PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), nitrogen oxides (NOx), sulfur dioxide (SO_2), and sulfuric acid (H_2SO_4) mist. The project is not a major source for Hazardous Air Pollutants.

PUBLIC AND U.S. EPA REVIEW:

An advertisement was placed in *The Gleaner* of Henderson, Kentucky on May 20, 2007 announcing the public comment period and announcing a public hearing At Henderson County Court House in Henderson, Kentucky on June 29, 2007. The Division for Air Quality received comments on the draft permit during the public hearing in Henderson, Kentucky on June 29, 2007. The public comment period expired 30 days from the date of publication.

Comments were received from Cash Creek Generation, LLC, U.S. EPA, Region 4, Environmental Law and Policy Center, Sierra Club, Warrick County, Newburg Township, City of Evansville, Dr. Theodore Stransky, Steve Jenkins of CH2M Hill and Reverend David E. Latham. Attachment A through Attachment J to this document lists the comments received and the Division's response to each comment. The U.S. EPA has 45 days to comment on this proposed permit.

EXHIBIT C

Abbreviations and acronyms are used in these comments

BACT - best available control technology
CAM - compliance assurance monitoring
EGR - exhaust gas recirculation
EPA - U.S. Environmental Protection Agency
IGCC - integrated gasification combined cycle
KDAQ - Kentucky Division for Air Quality
MMBtu -million British thermal units
PSD - prevention of significant deterioration
SCR - selective catalytic reduction
SNCR - selective non-catalytic reduction
SSM - startup, shutdown, and malfunctions
tpy - tons per year

In addition the following abbreviations are used for pollutants:

CO - carbon monoxide
NO_x - nitrogen oxides
PM - total particulate matter
PM_{10} - particulate matter with an aerodynamic diameter of 10 μm or less
$PM_{2.5}$ - particulate matter with an aerodynamic diameter of 2.5 μm or less
SO_2 - sulfur dioxide

ATTACHMENT A

Response to Comments

Comments on the Draft Title V Air Quality Permit submitted by Bryan Handy, Kentuckiana Engineering, on behalf of Cash Creek Generation LLC.

COMMENT 1:

Permit Location:

Emission Units 01 and 02, Synthesis/Natural Gas-Fired Combined Cycle Combustion Turbines [Emissions Units: HRSG-1 & HRSG-2], Description

Concern:

CCG requests that the Construction Commenced estimate be modified to reflect the current construction schedule. CCG's suggested modification follows.

Proposed Language:

Construction commenced: estimated - 2008

Division's response:

Comment acknowledged, change made.

COMMENT 2:

Permit Location:

Emission Units 01 and 02, Synthesis/Natural Gas-Fired Combined Cycle Combustion Turbines [Emissions Units: HRSG-1 & HRSG-2], Section (1)(e) Operating Limitations

Concern:

CCG requests that Section (1)(e) be clarified such that its application becomes effective at such time as the Cash Creek Generation gasifiers and combined cycle power block have both completed operational testing and entered commercial operation. This change is requested because the combined cycle power block is expected to commence operational testing with natural gas fuel approximately six (6) to twelve (12) months prior to the introduction of synthesis gas from the gasifiers. This testing period is required to fully demonstrate proper combined cycle functionality with natural gas fuel prior to the introduction of synthesis gas fuel. In addition, the gasifier construction period is intentionally staged to lag the combined cycle construction period to facilitate safety requirements pertaining to the overall construction process and to minimize air emissions during the start-up and testing process. CCG's suggested language change follows.

Proposed Language:

e) Pursuant to 40 CFR 60, Subpart Da, the permittee must operate such that more than 75 percent (by heat input) of the fuel combusted is synthetic-coal gas on a 12-month rolling average. This operating limitation shall commence at the earlier of twelve months after the combined cycle gas turbines commence operation or at such time as the gasifiers and associated acid gas removal systems commence operation to provide synthesis gas to the combined cycle gas turbines. .

Division's response:

The Division does not concur with the proposed changes to the permit language. Since the draft permit was issued, the final revisions to 40 CFR 60 Subpart Da have been promulgated. The Division has revised the permit to include the final wording of the NSPS, 40 CFR 60, Subpart Da.

<u>Comment 3:</u>

Permit Location:

Emission Units 01 and 02, Synthesis/Natural Gas-Fired Combined Cycle Combustion Turbines [Emissions Units: HRSG-1 & HRSG-2], Section (2) Emissions Limitations

Concern:

CCG requests that the averaging periods associated with the emission limitations in this section be revised to be consistent with the averaging periods that were provided in the application and served as the basis for the air emission modeling. CCG's suggested language changes are set out below.

Proposed Language:

a) Pursuant to 40 CFR 60 Subpart Da, and 401 KAR 51:017, nitrogen oxides emission level in the exhaust gas shall not exceed 0.0331 lb/MMBtu during any rolling <u>24-hour</u> average period (approximately 5 ppmvd @ 15 % oxygen (O_2)) when firing synthesis gas. The nitrogen oxides emission level in the exhaust gas shall not exceed 0.0246 lb/MMBtu during any rolling <u>24-hour</u> average period when firing natural gas. Additionally, the permittee shall keep records of the quantity of each fuel used and the actual NO_X and CO emissions during such periods. The ppm level of nitrogen oxides (at ISO standard conditions) and lb/MMBtu shall be demonstrated by stack test, and measured with use of a continuous emission monitor (CEM).

b) Pursuant to 401 KAR 51:017, the carbon monoxide emission level in the exhaust gas shall not exceed 0.0485 lb/MMBtu during any rolling <u>24-hour</u> average period when firing synthesis gas. The carbon monoxide emission level in the exhaust gas shall not exceed 0.0449 lb/MMBtu during any rolling <u>24-hour</u> average period when firing natural gas. Additionally, the permittee shall keep records of the quantity of each fuel used and the actual NO_X and CO emissions during such periods. The ppm level of carbon monoxide and lb/MMBtu shall be demonstrated by stack test, and measured with use of a continuous emission monitor (CEM).

e) Pursuant to 40 CFR 60 Subpart Da, and 401 KAR 51:017, filterable particulate/PM_{10} emissions shall not exceed 0.0085 lb/MMBtu <u>during any rolling three-hour average period when firing synthesis gas.</u> Total particulate/PM_{10} emissions shall not exceed 0.0217 lb/MMBtu <u>during any rolling three-hour average period when firing synthesis gas.</u> The lb/MMBtu level of particulate emissions shall be demonstrated by stack test, then calculated based on the emission factor derived during the test, fuel consumption data, fuel heat input, and fuel heat content [see specific monitoring requirements].

f) Pursuant to 401 KAR 51:017, sulfuric acid mist (H_2SO_4) emissions shall not exceed 0.0035 lb/MMBtu <u>during any rolling three-hour average period when firing synthesis gas.</u> The lb/MMBtu level of sulfuric acid mist emissions shall be demonstrated by stack test, then calculated based on the emission factor derived during the test, fuel consumption data, fuel heat input, and fuel heat content.

Division's response:

Comment acknowledged, changes made.

<u>Comment 4:</u>

Permit Location:

Emission Units 01 and 02, Synthesis/Natural Gas-Fired Combined Cycle Combustion Turbines [Emissions Units: HRSG-1 & HRSG-2], Section (4)(a) Specific Monitoring Requirements

Concern:

CCG requests that the Continuous Emissions Monitor ("CEM") provisions be expanded to allow a CEM for either oxygen or carbon dioxide as is provided in the cited regulation. CCG's suggested language change is set out below.

Proposed Language:

a) Pursuant to 401 KAR 60:005, Section 3(1)(c) incorporating by reference 40 CFR 60 Da; 401 KAR 52:020, Section 26; and 401 KAR 59:005, Section 4, the permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems for measuring the sulfur dioxide emissions, nitrogen oxides emissions, mercury, and either oxygen or carbon dioxide emissions. Additionally, a CEM system shall be installed, calibrated, maintained, and operated for measuring oxygen <u>or carbon dioxide</u> levels of the flue gases at each location where sulfur dioxide or nitrogen emissions are monitored. The permittee shall ensure the continuous emission monitoring systems are in compliance with the requirements of 401 KAR 59:005, Section 4.

Division's response:

Comment acknowledged, change made.

<u>Comment 5:</u>

Permit Location:

Emission Units 01 and 02, Synthesis/Natural Gas-Fired Combined Cycle Combustion Turbines [Emissions Units: HRSG-1 & HRSG-2], Section (6) Specific Reporting Requirements

Concern:

CCG requests that the averaging periods associated with the excess emissions reporting in this section be revised to be consistent with the averaging periods that were provided in the application and served as the basis for the air emission modeling. CCG's suggested language changes are set out below.

Proposed Language:

m) Pursuant to 401 KAR 52:020, Section 26, for nitrogen oxides, excess emissions are defined as any <u>24</u> hour period during which the average emissions (arithmetic average) exceed the applicable nitrogen oxides emission standard. These periods of excess emissions shall be reported quarterly.

n) Pursuant to 401 KAR 52:020, Section 26, excess emissions of sulfur dioxide are defined as any <u>3-hour</u> period during which the <u>average</u> sulfur dioxide emissions as indicated by continuous emission monitoring, or the sulfur content (or as otherwise required in an approved custom fuel sulfur monitoring plan) of the fuel being fired in the gas turbine(s) exceeds the limitations set forth in Subsection 2, Emission Limitations. These periods of excess emissions shall be reported quarterly.

o) Pursuant to 401 KAR 52:020, Section 26, for carbon monoxide, excess emissions are defined as any 24 hour period during which the average emissions (arithmetic average of three contiguous one hour periods) exceed the applicable carbon monoxide emission standard. These periods of excess emissions shall be reported quarterly.

q) Pursuant to 401 KAR 52:020, Section 26, for sulfuric acid mist (H_2SO_4) excess emissions are defined as any 3 hour period during which the average emissions exceed the applicable emission standard. These periods of excess emissions shall be reported quarterly.

Division's response:

Comment acknowledged, change made.

Comment 6:

Permit Location:

Emission Unit 03, Indirect Heat Exchanger (AUXB), Description

Concern:

CCG requests that the Construction Commenced estimate be modified to reflect the current construction schedule. CCG's suggested modification follows.

Proposed Language:

Construction commenced: estimated - 2009

Division's response:

Comment acknowledged, change made.

Comment 7:

Permit Location:

Emission Unit 04, Flare, Description

Concern:

CCG requests that the Construction Commenced estimate be modified to reflect the current construction schedule. CCG's suggested modification follows.

Proposed Language:

Construction commenced: estimated - 2009

Division's response:

Comment acknowledged, change made.

Comment 8:

Permit Location:

Emission Unit 05, Acid Gas Removal and Thermal Oxidizer, Description

Concern:

CCG requests that the Construction Commenced estimate be modified to reflect the current construction schedule. CCG's suggested modification follows.

Proposed Language:

Construction commenced: estimated - 2009

Division's response:

Comment acknowledged, change made.

Comment 9:

Permit Location:

Emission Unit 05, Acid Gas Removal and Thermal Oxidizer, Section (4) Specific Monitoring Requirements

Concern:

CCG requests that the references to flare in Section (4)(f) be replaced with the words "thermal oxidizer" and that reference to syngas flaring be deleted since the thermal oxidizer operates on a continuous basis when a gasifier is operating. CCG's suggested modifications follow.

Proposed Language:

f) The permittee shall perform a qualitative visual observation of the opacity of emissions from the thermal oxidizer on a weekly basis and maintain a log of the observations. If visible emissions from the thermal oxidizer are seen, the permittee shall determine the opacity of emissions by Reference Method 9 and initiate an inspection of the thermal oxidizer and the entire process making any necessary repairs.

Division's response:

Comment acknowledged, change made.

Comment 10:

Permit Location:

Emission Unit 11, Sulfur material handling, Description

Concern:

CCG requests that the Construction Commenced estimate be modified to reflect the current construction schedule. CCG's suggested modification follows.

Proposed Language:

Construction commenced: estimated - 2009

Division's response:

Comment acknowledged, change made.

Comment 11:

Permit Location:

Emission Unit 06, Coal Handling Operations (Coal crushing and processing operations), Description

Concern:

CCG requests that the barge unloading rate be reduced to be consistent with the application and that the Construction Commenced estimate be modified to reflect the current construction schedule. CCG's suggested modifications follow.

Proposed Language:

Equipment includes: Conveyor transfer-800tph (37), barge unloading-700tph (38), conveyor transfer-800tph (K3), transfer house #1-800tph (THDC33), transfer house #2-800tph (THDC34), coal reclaim-105tph (CRD35)

Construction commenced: estimated – 2009

Division's response:

Comment acknowledged, change made.

Comment 12:

Permit Location:

Emission Unit 07, Coal Handling Operations, Description

Concern:

CCG requests that the long-term storage pile acreage be changed to be consistent with the application and that the Construction Commenced estimate be modified to reflect the current construction schedule. CCG's suggested modifications follow.

Proposed Language:

Dead coal storage pile-90,000 tons (20a), coal stacker to long term storage pile-2.5 acres (20b)

Construction commenced: estimated 2009

Division's response:

Comment acknowledged, change made.

Comment 13:

Permit Location:

Emission Unit 07, Coal Handling Operations, Section (1) Operating Limitations

Concern:

CCG requests that Section (1)(c) be revised to limit its applicability to public roads consistent with the application air modeling and the intent of the cited regulation. CCG's suggested modification follows.

Proposed Language:

c) No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a <u>public</u> paved street or roadway, pursuant to 401 KAR 63:010, Section (4).

Division's response:

The Division does not concur. The word public is not included in the regulation; hence the permit language will not change.

<u>Comment 14:</u>

Permit Location:

Emission Unit 08, Cooling Tower, Description

Concern:

CCG requests that the number of cooling tower cells be decreased to be consistent with the application and that the Construction Commenced estimate be modified to reflect the current construction schedule.

Proposed Language:

<u>Ten</u> cell cooling tower
Construction commenced: estimated 200<u>9</u>

Division's response:

Comment acknowledged, change made.

<u>Comment 15:</u>

Permit Location:

Emission Unit 08, Cooling Tower, Section (1), Operating Limitations

Concern:

As engineering design has progressed respecting the Cash Creek Generating Station ("CC"), CCG has refined the proposed Cooling Tower ("CT") design and associated Particulate Matter ("PM") emissions. This comment provides details of the refined CT design and how the predicted particulate matter emissions compare to those previously proposed in the application. As detailed in Section 4.6.4 of the application, particulate matter (PM_{10}) emissions from a CT result from water and small particles entrained in the exiting air stream. These droplets of water and particulate are known as drift. The best means of reducing the level of drift emitted is to install drift eliminators. Using available water quality data, plant cooling requirements, and 0.0005% drift eliminators, CCG's design firm has prepared a refined water balance respecting CC. This water balance provides refined CT performance data and associated water quality parameters, including the Total Dissolved Solids ("TDS"), in the CT circulating water.

The current CT design includes a circulating water flow of 375,000 gallons per minute with maximum TDS equal to 2,300 ppm. These performance parameters result in CT PM_{10} emissions of 0.675 pounds per hour, with the 0.0005% drift eliminators determined to be BACT. The revised CT design parameters and resulting PM_{10} emissions are set out in Table 1, below and Attachment 1 to these comments which replaces Section 5.3 of the application.

Table 1: Revised Cooling Tower Parameters

Cooling Water Flow:	**375,000**	gpm, total
Liquid Drift Loss:	**0.0005**	% of cooling water circulation rate
TDS of Liquid Drift:	**2,300**	Ppm
PM_{10} Fraction:[a]	**31.3**	% of PM ≤ 10 μm
Operation Hours:	**8,760**	hrs/yr

Potential Cooling Tower Emissions

PM Emissions		**PM_{10} Emissions**	
(lb/hr)	**(tpy)**	**(lb/hr)**	**(tpy)**
2.16	**9.45**	**0.675**	**2.96**

[a] PM/PM_{10} fraction calculated based on 68.7% of the of the drift being deposited in or near the tower and results in 31.3% of the drift being emitted as PM_{10} emissions. As described in <u>Cooling Tower Drift, Its Measurement, Control and Environmental Effect.</u> Cooling Tower Institute Paper No: TP73-01

As a result of the refined CT design PM_{10} emissions are predicted to increase by 0.625 pounds per hour as compared to the emissions specified in the application. Since there is a predicted increase in PM_{10} emissions, CCG performed revised ambient air quality modeling to demonstrate compliance with all PSD and NAAQS requirements. Table 2, below, contains the results of the original PM_{10} modeling and Table 3, below, contains the results of the revised modeling with the increase in CT PM_{10} emissions. By comparing Tables 2 and 3, it is apparent that there is no change in the High-First-High ("HFH") ambient impacts associated with the refined CT PM_{10} emissions. Attachment 2 to these comments contains a complete revised modeling addendum including electronic copies of the input and output files. Additionally Attachment 3 to these comments contains revised Tables 3-2, 4-1 and 4-24 respecting the application.

Table 2: Original PM_{10} PIA Modeling Results

		SITE LULC	
		Nov-06	
		100% LOAD	
		24-HOUR	**ANNUAL**
	SIL	**5**	**1**
	SMC	**10**	**NA**
		24 HR	**ANNUAL**
YEAR		**ug/m^3**	**ug/m^3**
1990	**HFH**	2.52	**0.41**
	X	464,387.91	463,611.00
	Y	4,175,620.75	4,173,769.00
1991	**HFH**	2.82	0.37
	X	462,288.94	463,611.00
	Y	4,173,312.00	4,173,769.00
1992	**HFH**	3.17	0.38
	X	463,372.75	463,611.00
	Y	4,172,482.25	4,173,769.00
1993	**HFH**	3.44	0.37
	X	462,883.94	463,611.00
	Y	4,172,479.00	4,173,769.00
1994	**HFH**	**3.997**	0.36
	X	462,344.56	463,611.00
	Y	4,173,037.50	4,173,769.00

Table 3: Revised PM_{10} PIA Modeling Results

		Site LULC **100 % LOAD**	
		24-HOUR	**ANNUAL**
	SIL	**5**	**1**
	SMC	**10**	**NA**
		24 HR	**ANNUAL**
YEAR		**ug/m^3**	**ug/m^3**
1990	**HFH**		**0.41**
	X		**463611.00**
	Y		**4173769.00**
1994	**HFH**	**3.997**	
	X	**462344.56**	
	Y	**4173037.50**	

Proposed Language:

CCG requests that the following modifications be made in the draft permit to reflect the refined cooling tower design and resultant modeling.

c) Pursuant to 401 KAR 51:017, the cooling tower circulating water rate shall not exceed 375,000 gals/minute on a daily average.

d) Pursuant to 401 KAR 51:017 the total dissolved solids (TDS) concentration in the circulated cooling water shall not exceed a TDS concentration of 2,300 parts per million.

Division's response:

Comment acknowledged, change made.

Comment 16:

Permit Location:

Emission Unit 09, Emergency Fire Pump, Description

Concern:

CCG requests that the Construction Commenced estimate be modified to reflect the current construction schedule. CCG's suggested modification follows.

Proposed Language:

Construction commenced: estimated - 2010

Division's response:

Comment acknowledged, change made.

Comment 17:

Permit Location:

Emission Unit 09, Emergency Fire Pump, Section (3) Testing Requirements

Concern:

CCG requests that a typographical error in Section (3)(b) be corrected.

Proposed Language:

b) Pursuant to 40 CFR 60.4244, [per proposed revisions to NSPS Subpart JJJJ published in the Federal Register on June 12, 2006] Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in paragraphs (1) through (6) of this section.

Division's response:

Comment acknowledged, change made.

Comment 18:

Permit Location:

Emission Unit 10, Plant Roadways [Emissions Units: HRP], Description

Concern:

CCG requests that the Construction Commenced estimate be modified to reflect the current construction schedule. CCG's suggested modification follows.

Proposed Language:

CCG proposes the following language to address the
Construction commenced: estimated - 2008

Division's response:

Comment acknowledged, change made.

Comment 19:

Permit Location:

Emission Unit 10, Plant Roadways [Emissions Units: HRP], Section (1) Operating Limitations

Concern:

CCG requests that Section (1)(c) be revised to limit its applicability to public roads consistent with the application air modeling and the intent of the cited regulation. CCG's suggested modification follows.

Proposed Language:

c) No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a public paved street or roadway, pursuant to 401 KAR 63:010, Section (4).

Division's response:

See Division response to Comment #13 above.

Comment 20:

Permit Location:

Section (D)(2), Source Emission Limitations and Testing Requirements

Concern:

CCG requests that references to VOCs in this Section be deleted as there is no VOC PSD BACT limit specified for Emission Units 01 and 02. In addition, CCG requests that Sections (D)(2)(3) and (D)(2)(4) be modified by replacing the word "condensable" with "total" to provide consistency with the applicable emission limitation. CCG's suggested modifications are shown below.

Proposed Language:

2. Particulate matter (PM/PM_{10}/$PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_X) carbon monoxide (CO), mercury (Hg) and sulfuric acid mist (H_2SO_4) emissions, measured by applicable reference methods, or an equivalent or alternative method specified in 40 C.F.R. Chapter I, or by a test method specified in the state implementation plan shall not exceed the respective limitations specified herein.

3. Emission Units 01 and 02 shall be performance tested initially for compliance with the emission standards for PM/PM_{10} (filterable and total); sulfur dioxide (SO_2); nitrogen oxides (NO_X); carbon monoxide (CO), mercury; and H_2SO_4 by applicable reference methods, or by equivalent or alternative test methods specified in this permit or approved by the cabinet (and U.S.EPA, if required).

4. Emission Units 01 and 02 shall be performance tested biannually (once every 24 months) for compliance with the emission standards for PM/PM_{10} (filterable and total); mercury and H_2SO_4 by applicable reference methods, or by equivalent or alternative test methods

specified in this permit or approved by the cabinet (and U.S.EPA, if required).

Division's response:

Comment acknowledged, change made.

Comment 21:

Permit Location:

Section (G)(d), General Provisions, Construction, Start-Up, and Initial Compliance Demonstration Requirements

Concern:

CCG requests that the number of emission units be revised from ten (10) to eleven (11).

Proposed Language:

Pursuant to a duly submitted application the Kentucky Division of Air Quality hereby authorizes the construction of the equipment described herein, Emissions Units 01 through 11 in accordance with the terms and conditions of this permit.

Division's response:

Comment acknowledged, change made.

ATTACHMENT B

Response to Comments

Comments on the Draft Title V Air Quality Permit submitted by Greg M. Worley of U.S. EPA Region 4.

1. Sulfur Dioxide BACT Assessment - KDAQ's BACT assessment for SO_2 appears to focus solely on emissions from the combustion turbines and on the acid gas removal technologies that determine combustion turbine SO_2 emissions. Another source of SO_2 emissions is the sulfur recovery system. Estimated SO_2 emissions from the thermal oxidizer used to control sulfur-containing gases from the tail gas treatment unit are 91.3 tpy. The final statement of basis should explain the factors that affect SO_2 emissions from the sulfur recovery system, what considerations were given to minimizing these emissions, and why an SO_2 emissions rate producing emissions of 91.3 tpy represents BACT. In this explanation, we recommend including a brief discussion of how the selection of Selexol™ rather than Rectisol™ affects SO_2 emissions from the tail gas treatment unit thermal oxidizer. We also note that the emissions limitations for the tail gas treatment unit thermal oxidizer in draft permit Condition B.2, Emissions Unit 05, do not include a specific hourly SO_2 emissions limit equivalent to 91.3 tpy, but rather specify emissions restrictions in other units. We recommend that the final statement of basis contain an explanation of how the emissions restrictions in the permit assure an SO_2 emissions rate of no more than 91.3 tpy.

Division's Response:

In this IGCC design, the acid gas removal unit extracts H2S and COS from the synthesis gas. Either Selexol or Rectisol can be used in the acid gas removal unit. Based on economic considerations and the insignificance of the removal efficiency difference between Selexol and Rectisol, the Division concurs with CCG that Selexol is the correct choice for BACT in the acid gas removal unit for the synthesis gas going to the combustion turbines.

Use of Selexol determines the amount of sulfur contained in the gases that proceed from the acid gas removal unit to the sulfur recovery system. The sulfur recovery system consists of the two Claus stages, the thermal oxidizer and the flare. The amount of sulfur in the gases that go to the sulfur recovery system is minimally impacted by the 99.8% removed by Selexol or the 99.9% that might be removed by Rectisol (a difference of only two pounds per ton of sulfur removed); it is not a significant factor in emissions from the sulfur recovery unit. The emission limit on the Claus stages is the only significant factor determining emissions of sulfur from the sulfur recovery unit.

The Division did an extensive review of permitted sulfur recovery units for refineries, natural gas treatment processes, and coal gasification systems. Based on the Division's research, an exhaust stream from the sulfur recovery system containing 100 ppm sulfur is the best permitted emission rate and the best emission rate demonstrated in practice by any type of sulfur recovery unit. The Division set the BACT limit for sulfur from the sulfur recovery unit at 100 ppm. This is lower than any other permitted IGCC unit **and is significantly lower** *than the proposed standard of performance for petroleum refineries which allows an emission limit of 250 ppm (72 Federal Register 27178, Monday, May 14, 2007).*

The applicant did not propose an emission limit from the sulfur recovery unit but instead proposed an hourly emission rate of 20.82 lbs/hr, which equates to an annual emission rate of 91.2 tpy of sulfur dioxide. The Division calculated the annual emission rate of sulfur dioxide based on the 100 ppm emission limit, and determined that it would be less than the proposed emission rate of 91.2 tpy of sulfur dioxide. The Division did not accept the 91.2 tpy sulfur dioxide emission estimate included in the Statement of Basis in Table 2-1 as a BACT limit, nor is it included in the permit as such. Instead, the Division imposed the 100 ppm limit contained in the permit as BACT. The Division has included this explanation in the revised Statement of Basis.

2. Startup, Shutdown, Malfunction Provisions for Combustion Turbines - Condition B.2.i), Emissions Units 01 and 02, in the draft permit contains provisions for startup, shutdown, and malfunctions (SSM) of the combustion turbines. The condition reads in part as follows: "Pursuant to 401 KAR 51:017, duration of startup, shutdown and malfunction periods are limited to 48 hours per occurrence with 3 annual occurrences for 2 gasifiers and with 29 annual occurrences for 1 gasifier. However, this requirement is waived during the first year after the initial demonstration of compliance." We have the following comments about this permit condition:

   a. The meaning of the terms "startup" and "shutdown" in this condition is unclear. The condition itself applies specifically to combustion turbines. Typical combined cycle combustion turbines can be started up and shut down in a matter of a few hours, not 48 hours. If the terms startup and shutdown refer to starting up and shutting down the entire gasifier system that generates synthetic gas for the combustion turbines, this should be made clear. For additional clarification, KDAQ may wish to add a separate SSM provision applicable to extended periods when the combustion turbines are fired on natural gas. Any SSM exception for natural gas combustion should be restricted to a period no longer than a few hours per occurrence.

Division's response:

The Division concurs with the comment and has modified the permit language to clarify which startup and shutdown is addressed in permit condition B. 2. (l) (formerly B. 2. (i) in the draft permit). U.S. EPA is correct in that language was referring to the start-up and shutdown (S&S) of the gasifier, and the coordinated S&S of the turbines. There are three distinct phases of start-up for the operation. First, there is the start-up of the turbines while firing natural gas. Secondly there is startup of the gasifier to produce synthesis gas, this is the step that is being referred to in the permit condition B. 2. (l). The permit has been changed to reflect this. Thirdly, there is a period that can occur when the turbine is being switched from Natural Gas to Synthesis gas. Since construction and shakedown of the turbines are expected to occur prior to the gasifiers, there is a potential for the unit to be used to supply peak power while combusting natural gas prior to the gasifier becoming operational. Due to the rapid ability to perform S&S for the turbines while firing natural gas, no source specific requirements are included in this permit. Periods of start-up, shutdown and malfunctions are covered under the general requirements of 401 KAR 50:055 and 40 CFR 60 Subpart Da.

   b. Does the phrase "this requirement" refer to the 48-hour duration per occurrence, the number of occurrences, or both?

Division's response:

This requirement refers both to the duration and the number of occurrences. Changes have been made to the permit.

c. The statement of basis should include a justification for granting a waiver during the first year of operation.

Division's response:

The Division has corrected the regulatory citation to read "401 KAR 52:020" instead of "401 KAR 51:017". Due to the limited amount of operational experience with IGCC units of this size and complexity, the Division has concluded that it is not unreasonable to include a waiver of the start-up and shutdown quantities and duration for the first year of operation of the facility. This explanation has been included in the Statement of Basis.

3. Fine Particles - We have the following comments related to $PM_{2.5}$:

a. On page 14 of the statement of basis, KDAQ lists $PM_{2.5}$ as a pollutant subject to BACT. However, the draft permit does not contain a BACT emissions limit for $PM_{2.5}$. If KDAQ is using PM_{10} in the BACT evaluation as a surrogate for $PM_{2.5}$ in accordance with current EPA guidance, this should be explained.

Division's response:

Comment acknowledged. Changes made to the Statement of Basis.

b. In the air quality impact analysis section of the statement of basis no mention is made of $PM_{2.5}$. If KDAQ is using PM_{10} in the impact analysis as a surrogate for $PM_{2.5}$ in accordance with current EPA guidance, this should be explained.

Division's response:

Comment acknowledged. Changes made to the Statement of Basis.

4. Compliance Assurance Monitoring - KDAQ acknowledges the applicability of CAM requirements to NO_x emissions from the proposed combustion turbines. KDAQ might also wish to explain in the final determination why it decided that CAM requirements are not applicable to the control of regulated sulfur compounds by thermal oxidation in the tail gas treatment section of the sulfur recovery system.

Division's response:

For CAM to apply to a unit, three conditions must be met. The first is that precontrolled emissions are greater than a hundred tons per year, second is that there is an emission standard, and third that there is a control device used for compliance. For emissions of sulfur compounds, the second two conditions are certainly met. The first is not. During the review process, a "scratch pad" calculation was performed that took the post thermal oxidizer emission rate of 91.2 tons per year, assuming that all TRS was in the form of Carbonyl sulfide (COS) with a molecular weight of 60.8 g/mol. During combustion, one molecule of sulfur dioxide is formed per molecule of COS. Molecular weight of sulfur dioxide is 64.1. Therefore, uncontrolled emissions of TRS from the SRU are 91.2 X (60.8/64.1) = 86.5 tons per year. The assumption that all TRS is COS is an extreme case, as most of it would be in the form of H2S, which has a molecular weight of 34. Since uncontrolled emissions are less than 100 tons per year, CAM is not applicable.

5. Number of Gasifiers - On page 1 of the statement of basis, KDAQ states that the permit

authorizes up to three gasifiers. We can find no reference anywhere in the draft permit to a three-gasifier configuration. One of the permit conditions for the combustion turbines provides for up to two gasifiers.

Division's response:

The editorial error has been corrected to reflect the permitting of two gasifiers.

6. Comparison with Christian County Generation Permit - A final PSD permit was recently issued for the Christian County Generation IGCC project in Christian County, Illinois. This final permit was not available at the time KDAQ issued the draft permit for the Cash Creek project. Our understanding is that the Cash Creek and Christian County Generation projects have the same developer and essentially the same design. Therefore, we recommend that KDAQ review the final permit for Christian County Generation to see if any portions of the permit might be helpful in developing a final permit for Cash Creek. In our own review of the Christian County Generation final permit we have noted that the SO_2 and PM/PM_{10} emissions limits for the combustion turbines when firing natural gas are slightly lower than the limits in the draft permit for Cash Creek.

Division response:

The Division acknowledges the comment and has reviewed the Christian County permit. Changes have been made to the Cash Creek permit and the limits are now consistent with the Christian County permit.

7. Miscellaneous - We have the following miscellaneous comments:

a. In the assessment of BACT for the 278.8 MMBtu/hr auxiliary boiler, KDAQ states that BACT is based on use of low NO_x burners, good combustion practices, and clean fuel (natural gas), and on restricting hours of operation to 500 hours per year. For completeness sake, KDAQ might consider stating that other controls sometimes used on large natural gas-fired boilers - such as FGR, SCR, and SNCR - would be either technically or economically infeasible when considered in addition to the control methods that will be required.

Division's response:

Comment acknowledged and the suggestion has been include in the revised statement of basis.

b. Table 4-13 on page 26 of the statement of basis is a summary of the combustion turbines BACT determination. This table is missing values for natural gas combustion in the column headed "Emission Limit Based on CT Heat Input." Also, the averaging time for NO_x and CO emissions limits is listed as 24 hours in this table, whereas the averaging time for both pollutants in the draft permit is 3 hours.

Division's response:

The natural gas values were incorrectly entered into the gasifier heat input column and have been corrected in Table 4-13, and that table has been modified to remove the gasifier heat input column, since that is not relevant to the permit. The NO_x and CO averaging times have been changed to twenty-four hours in the proposed permit.

c. The draft permit, the word "are" in the second line of Condition B.2.i), Emissions Units 01 and 02 (combustion turbines), should be "is," and the word "waved" in this condition should be "waived."

Division's response:

Comment acknowledged, change made.

d. In the draft permit, the description section for each emissions unit contains an estimate of the construction commencement date. For some units this date is 2007 and for other units it is 2010. Although the description sections are not enforceable, we recommend correcting this apparent inconsistency.

Division's response:

Corrections made. See comments in Attachment A.

e. In draft permit Condition B.1.c), Emissions Units 01 and 02 (combustion turbines), KDAQ is allowing the restriction on the quantity of natural gas usage during any 12-month period to be waived during the first 36 months of operation. A justification for this waiver should be provided in the statement of basis.

Division's response:

Comment acknowledged. This requirement has been deleted from the permit as a result of the final promulgation of 40 CFR 60 Subpart Da.

f. Draft permit Condition B.1, Emissions Unit 03 (auxiliary boiler), contains this statement: "The auxiliary boiler shall only operate during startup periods." KDAQ should specify the equipment to which the term "startup" refers.

Division's response:

Comment acknowledged, a clarification has been made to the permit.

g. In draft permit Condition B.1, Emissions Unit 03 (auxiliary boiler), KDAQ is allowing the restriction of no more than 500 hours of operation during any consecutive 12-month period to be waived during the first 12 months of operation. A justification for this waiver should be provided in the statement of basis. In addition, unless KDAQ intends to allow continuous operation of the auxiliary boiler during the first 12 months of operation, KDAQ should consider restricting use of the auxiliary boiler during the first 12 months to some duration that is greater than 500 hours but less than 8,760 hours.

Division's response:

Comment acknowledged, and the waiver in the permit has been deleted. The regulatory citation has also been corrected.

h. In Condition D.7 of the draft permit, KDAQ repeats the 500-hour-per-12-month operating restriction for the auxiliary boiler but does not repeat the waiver for the first 12 months of operation. We recommend repeating the waiver to avoid confusion.

Division's response:

Comment acknowledged. The waiver in the permit has been deleted.

ATTACHMENT C

Response to Comments

Comments on the Draft Title V Air Quality Permit submitted by Wallace McMullen, Energy Chair of Cumberland Chapter of the Sierra Club.

1. This Plant Will Aggravate Air Quality Problems

Although the Cash Creek permit is titled a Prevention of Significant Deterioration permit, it will in fact exacerbate air quality problems in the surrounding area.

The Indiana counties directly north of the proposed plant location, Warrick and Vanderburgh, are already in non-attainment for fine particles. This plant will aggravate the already existing air quality problems there. Please note that both the Warrick County Commissioners and the Newburgh Town Board have passed resolutions opposing Cash Creek due to its impact on the Warrick County non-attainment area. Nearby Evansville, Indiana, a metropolitan area with well over 100,000 residents will also be seriously impacted by proposed facility. It already is struggling with dirty air problems, which the Cash Creek plant will only aggravate.

Further, the EPA is the process of tightening the ozone standard. When the standard is tightened to 70 or 75 ppm from 84 ppm, Warrick and Vanderburgh counties will be further from meeting clean air standards, and Daviess County in Kentucky will be in non-attainment. (at 70 ppm) Permitting this plant to pump 965 tons per year of CO, 700 tons per year of NOx, plus volatile organic compounds, plus hazardous air pollutants, plus sulfuric acid mist into the air in this region is just digging deeper into the hole that these counties and their residents are already stuck down in.

Division's Response:

> *The Division acknowledges the comment. The air quality modeling has shown that there will not be any exceedances of any air quality standards as a result of this new construction. Kentucky regulations define when a source outside of a non-attainment area has a significant impact upon a nonattainment area. For PM_{10}, this level is set at 1.0 ug /m^3 for an annual average and 5 ug /m^3 for a twenty-four hour average. Modeling for this facility predicts a maximum impact, at any location, of PM_{10} on an annual average basis of 0.31 ug /m^3 and a 24-hour average of 4.0 ug /m^3. Since the maximum impact is less than the significance level for a nonattainment area, the Division had no further regulatory basis to perform additional analysis.*

2. This Plant Will Be Bad For Human Health

The pollutants this plant will emit will impair the air quality and thereby have an adverse impact on human health for people living within the affected airshed. Pollutants such as NOx, SOx, and sulfuric acid mist will aggravate asthma problems, tend to increase cases of cardiovascular disease, and increase heart attacks.

EPA's consultants estimate that fine particle pollution from power plants shortens the lives of 745 Kentuckians each year. Kentuckians already have the second highest risk in the country of dying from power plant pollution. Statewide, fine particle pollution from power plants also causes 16,440 asthma attacks every year, 798 of which are so severe they require emergency room treatment with associated lost workdays and school days.[1]

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[1] Abt Associates, "Power Plant Emissions: Particulate Matter-Related Health Damages and the Benefits of Alternative Emission Reduction Scenarios" June 2004.

Based on EPA data, each year, 110 lung cancer deaths and 1,022 heart attacks in Kentucky are attributable to power plant pollution.[2] The studies done by Abt Associates indicate that four premature deaths per year may result from the pollution emitted by this Cash Creek plant.[3]

Division's Response:

> *The Division acknowledges the comment. The air quality modeling has shown that there will not be any exceedances of any air quality standards as a result of this new construction.*

3. No Customers Depend On Electricity From This Plant

This is a merchant plant, proposed solely for the speculative premise that by the time it is built, it can sell electricity on the open market for a profit. ERORA does not have a defined service area containing customers for this plant. If it is not built, no one will suffer a lack of electricity, and this fact should have been considered in the alternatives analysis in considering BACT limits.

Division's Response:

> *The Division acknowledges the comment. The Division has no authority to approve or deny the construction of EGUs based on market demand. Comments of this nature should be addressed to the Kentucky Public Service Commission.*

4. BACT Limits on pollution

a. NOx BACT Limits

The Statement of Basis states at 4.5.3:

> Cash Creek selected SCR and nitrogen diluent to control NO_x emissions from the source. This combination of control processes with a NO_x emission limit of 0.0246 lb/MMBtu, based on a 24-hr rolling average represents BACT for the Cash Creek IGCC combustion turbines when firing syngas and natural gas.

But the permit itself is not consistent with the explanation in the Statement of Basis, as it shows a NOx limit of 0.0331 lb/mmBtu, three-hour rolling average, for burning syngas, and the limit of 0.0246 lb/mmBtu only for firing natural gas, but on a three hour rolling average.

A primary purpose of the statement of basis is to provide an explanation of the permitting authority's decisions. But when the statement of basis and the permit have completely different statements about the proper BACT limit, no one knows what is going on.
We expect that the Statement of Basis:

> …is an explanation of why the permit contains the provisions that it does and why it does not contain other provisions that might otherwise appear to be applicable. The purpose of the statement is to enable EPA and other interested parties to effectively review the permit by providing information regarding decisions made by the Permitting Authority in drafting the permit.[4]

In this case, that intent is completely violated. We suggest that probably the correct limit is 0.0246 lb/mmBtu or lower, on a three hour average for all potential fuels, but a re-working of both the Statement of Basis (SOB) and the NOx limits in the permit is needed before a correct permit can be

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[2] From C. A. Pope, et. al., Lung Cancer, Cardiopulmonary Mortality and Long-Term Exposure to Fine Particulate Air Pollution. Journal of the American Medical Association Vol. 287, no 9. - March 6, 2002. quoted at http://cta.policy.net/regional/ky/

[3] Abt Associates, *The Particulate-Related Health Benefitsof Reducing Power Plant Emissions*, (October 2000). Available online at: http://www.catf.us/publications/reports/Abt_PM_report.php

[4] Joan Cabreza, Memorandum to Region 10 State and Local Air Pollution Agencies, Region 10 Q &A #2: Title V Permit Development, March 19, 1996

issued.

Division's response:

> *Comment acknowledged, The NOx BACT limit for the combustion turbines is 0.0331 lb/MMBtu when firing synthesis gas, and 0.0246 lb/MMBtu when firing natural gas. Both limits are on a twenty-four hour rolling average. See the Revised Statement of Basis Section 4.5.3 and 4.6, Table 4-13. Also refer to Attachment A response to comment # 3.*

b. Particulate Matter BACT

The draft permit proposes a total PM limit of 0.0217 lb/MMBtu, based on a stack test. This proposed total PM limit is higher than the total PM limit for Spurlock IV, which is 0.012 lb/MMBtu. KDAQ indicates in the Statement of Basis that emission controls such as Wet Electrostatic Precipitators and Wet Flue Gas Desulfurization (WFGD) are readily available to remove more particulate matter, but did not require them in the permit, and apparently did not require a full BACT analysis of more complete particulate control. The limit for Spurlock IV establishes that 0.012 lb/MMBtu is technologically feasible, and therefore that should be the maximum possible limit for Cash Creek, pending a more complete BACT analysis.

Electrostatic precipitators and WFGD are widely used as post-combustion controls on new and existing coal plants. KDAQ has not identified any technical reason why such controls could not be used on an IGCC plant. The PM BACT analysis must be redone with, at a minimum, a consideration of these controls. KDAQ must propose new PM limits reflecting the use of post-combustion controls in addition to pre-combustion syngas scrubbing, as well as BACT limits shown feasible by other plants such as Spurlock IV.

Division's response:

> *The Division does not concur. Spurlock IV is a coal-fired Circulating Fluidized Bed Combustion unit, while Cash Creek proposes to use integrated gasification combined cycle (IGCC) units. For an IGCC unit, precombustion control is required as an integral part of the operation of the turbine. The Division is not aware of any combined cycle turbines equipped with post combustion particulate controls nor of any determination that these controls are available for an IGCC unit.*

c. $PM_{2.5}$ BACT.

The Draft Permit does not include a BACT limit for $PM_{2.5}$ emissions. Nor does it appear that KDAQ even considered such a limit. This is unlawful and must be corrected before a PSD permit can issue. The federal PSD program requires a BACT limit "for each pollutant subject to regulation under the Act that it would have the potential to emit in significant amounts." [40 C.F.R. § 52.21(j)(2)]. $PM_{2.5}$ is "a pollutant subject to regulation under the Act" because EPA established a NAAQS for $PM_{2.5}$ in 1997.[5] Moreover, $PM_{2.5}$ will be emitted from this facility in a "significant" amount because it will be emitted at "any emission rate." [40 C.F.R. § 52.21(b)(23)(ii)]. For these reasons a BACT limit for *$PM_{2.5}$* is required.[6] Nevertheless, the Draft Permit does not contain a BACT limit for *$PM_{2.5}$* emissions. This is a deficiency that must be corrected before a final PSD permit can be issued.

Division's response:

> *While the Division acknowledges that $PM_{2.5}$ is a regulated NSR pollutant, at this time EPA has not yet implemented NSR regulations for $PM_{2.5}$ NAAQS. It is well established that EPA*

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[5] 62 Fed. Reg. 38711; 40 C.F.R. § 50.7.

[6] see 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j)

has proposed the interim use of PM_{10} as a surrogate for $PM_{2.5}$ until NSR rules have been implemented. EPA has represented that:

"In view of the significant technical difficulties that now exist with respect to $PM_{2.5}$ monitoring, emissions, estimation, and modeling, EPA believes that PM_{10} may properly be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements until these difficulties are resolved. When the technical difficulties are resolved, EPA will amend the PSD regulations under 40 C.F.R. §51.166 and 52.21 to establish a $PM_{2.5}$ significant emissions rate and EPA will also promulgate other appropriate regulatory measures pertinent to $PM_{2.5}$, and its precursors."
Memorandum from John Seitz, Office of Air Quality Planning and Standards, "Interim Implementation of New Source Review Requirements for PM2.5" (October 21,1997).

This position was recently reaffirmed in specific guidance to the states:
"Using the surrogate $PM_{2.5}$ nonattainment major NSR program, States should assume that a major -stationary source's PM_{10}, emissions represent $PM_{2.5}$ emissions and regulate these emissions using either Appendix S or the States' SIP-approved nonattainment major NSR program."
Memorandum from Stephen Page, Office of Air Quality and Planning and Standards (April 5, 2005).

d. Cleaner Fuels

There are at least two fuels that are cleaner than synfuel that must be considered in the top-down BACT determination for each of the regulated pollutants, including particulate matter. The draft permit sets NOx and CO limits for when the facility is burning natural gas.

3 Hour Average	Pollutant Limit, Lb/MMbtu
NOx coal	0.0331
NOx natural gas	0.0246
CO coal	0.0485
CO natural gas	0.0449

These proposed limits when the project is firing natural gas are lower than the limits for firing synfuel. Therefore, the top-down BACT analysis must consider the use of cleaner fuels, including natural gas, as available clean fuels. Since the facility is specifically designed to be able to fire natural gas, alone or in combination with syngas, there is no argument that burning gas would "redefine the source."

Similarly, by burning a mix of natural gas with syngas, the source could lower both the pound-per-MMBtu emission rate and the hourly emission rate for each of the regulated pollutants, including PM. While natural-gas fired generation must be considered, as noted above, a BACT analysis must also consider mixing natural gas with syngas. If the cost effectiveness of combusting gas, or a combination of gas and syngas, is within the range generally accepted as cost-effective for similar sources (i.e., under $10,000 per ton of pollutant removed), the BACT limit for PM must be established based on a BACT analysis that factors in natural gas.

Another available clean fuel that has received no discussion in the agency's top-down BACT analysis is biomass. There are numerous examples of coal plants co-firing biomass that should be considered in the top-down BACT analysis. For example, the St. Paul heating plant burns approximately sixty percent biomass and forty percent coal.[7] The biomass is primarily waste wood from tree trimmings in the Twin Cities and other industrial activities. The Xcel Bay Point power plant in Ashland, Wisconsin, also burns large amounts of wood waste, consisting primarily of sawdust.

The U.S. Department of Energy has urged federal facility managers to consider co-firing up to 20 percent biomass in existing coal-fired boilers.[8] In the Netherlands, the four electricity generation companies (EPON, EPZ, EZH and UNA) have all developed plans to modify their conventional coal fired installations to accommodate woody biomass as a co-fuel.[9] The types of available biomass include wood wastes, agricultural waste, switchgrass and prairie grasses.[10] In Kentucky one might conceivably consider tobacco as a biomass feedstock

The BACT analysis must consider the burning of biomass, natural gas, and syngas in setting the limits for PM, NOx, and CO.

Division's response:

> *The Division does not concur. The IGCC process will use coal to produce synthesis gas (syngas) as the primary fuel (natural gas is a secondary fuel). The facility is specifically designed for synthesis gas as the primary fuel alone and not in combination with natural gas. The lower heating value of biomass has to date precluded its use as a feedstock for gasification.*

5. Monitoring and Enforceability Issues

a. Combustion Turbine Flu(sic) Opacity

The combustion turbine flu(sic) opacity has a limit of 20% (6 minute average), except for one 6-minute period per hour of not more that 27 %. However, no recordkeeping or reporting is called for in the permit, and there is not monitoring of the turbine exhaust opacity required in the Specific Monitoring Requirements section (Permit, pages 5 through 8). We do see a Testing Requirement with wording that seems to imply that compliance with the limit will be ignored, as there is no requirement for action if the limit is exceeded. Testing Requirements, p. 4:

> The permittee shall determine the opacity of emissions from the stack by U.S. EPA Reference Method 9 weekly, or more frequently if requested by the Division.

The opacity limit is not practicably enforceable without monitoring, recordkeeping, and reporting requirements. These requirements need to be added before the permit can be issued properly.

Division's response:

> *The Division does not concur. Monitoring and reporting have been and still are in the permit, however a requirement for recordkeeping, Section B 5(g) has been added to the permit. The opacity limits have been set pursuant to 40 CFR 60, Subpart Da. That regulation contains no monitoring, record keeping or reporting requirements. This permit does, contain requirements for compliance certification and periodic reporting.*

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[7] http://www.districtenergy.com/

[8] http://www1.eere.energy.gov/biomass/pdfs/33811.pdf

[9] http://www.eeci.net/archive/biobase/B10252.html

[10] http://www.nsf.gov/news/news_summ.jsp?cntn_id=108206

b. PM Compliance Assurance Monitoring and CEMS.

The permit is required to have Compliance Assurance Monitoring for PM10, as the facility will emit over 100 tpy of the pollutant. See 40 CFR Part 64. The draft permit, however, makes no mention of CAM for PM10. This omission must be fixed before a final permit can be issued.

KDAQ recently required the use of a PM CEMS in the PSD permit for the EKPC Spurlock 4 CFB project, and there is extensive experience of PM CEMS on coal plants as a result of numerous NSR settlements around the country. Therefore, KDAQ must also require the use of a PM CEMS in this permit.

Also, a PM CEMS will be required for determining continuing compliance with the permit's PM filterable limit. The permit must be revised to include these requirements before the permit can be issued properly.

Division's response:

> *For CAM to apply to a unit, three conditions must be met. The first is that pre controlled emissions are greater than a hundred tons per year, secondly that there is an emission standard, and lastly that there is a control device used for compliance. For emissions of PM/PM_{10} the first two conditions are met, but the last one is not. There is no active control device for PM/PM_{10}, therefore CAM is not required.*

6. Bulk Handling, Storage, Processing and Loadout Operations.

A. Emissions Limit

KDAQ did not include an emission limitation for Unit 7 (coal pile). Instead, the agency specified the use of use of certain controls and cites an approximate expected removal efficiency. (See the SOB at p. 19). BUT, BACT is an emission limitation. Controls like baghouses and methods such as "compaction" and "water suppression control methods" therefore do not constitute BACT, but are descriptions of how a source might reach a BACT limit. The permit should include specific numeric limits on material handling emissions. (The permit for Indeck-Elwood contains examples). Also, vague permit language regarding "reasonable precautions" as an operating limitation for Unit 7 is not a practicably enforceable requirement. (Permit at p. 24 of 51).[11]

Division's response:

> *The Division does not concur that BACT must be stated as a numerical limit. The definition of BACT includes design, equipment, work practice or operational standards or combination of standards approved by the Cabinet. The term "reasonable precautions" is the language of the regulation found at 401 KAR 63:010. Consistent with 401 KAR 51:017 the permit contains conditions which require the unit to be maintained and operated properly.*

B. Compliance Terms Should Be Clearly Defined

The term "reasonable precautions" is vague and not practicably enforceable. Therefore, the conditions in which the term is used must be modified to explicitly state what the applicant must do to be in compliance. These conditions include Unit 07 (coal handling), Condition 1(a); Unit 08 (cooling tower), Condition 1 (a) and 2(b); and Unit 10 (roadways), Condition 1(a).

Division's response:

> *The term "reasonable precautions" is contained in Kentucky's regulation 401 KAR 63:010.*

7. The IGCC Plant And Coal Mine Should Be Permitted As A Single Facility

The Statement Of Basis states that "the primary coal supply is expected be provided by the Patriot Coal Company, which operates an existing underground and surface mining and processing

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[11] See U.S. EPA Region 9, "Title V Permit Review Guidelines: Practical Enforceability," [Sept. 1999]

operation adjacent to the Cash Creek location. The coal will be delivered by a conveyor from the mine to an onsite receiving transfer-house."[12] KDAQ issued the Patriot coal processing facility a construction and operating permit, Permit No. S-06-333, on December 6, 2006. Due to the increased production at Patriot necessitated by Cash Creek,[13] and the interdependence of the two facilities, the mine and plant must be jointly evaluated as one major emissions source for the purposes of the PSD permit for Cash Creek. This means that in evaluating whether the Cash Creek source's emissions will be significant for determining incremental impacts and required controls, both facilities must be modeled together. Further, in determining the Cash Creek source's impact area for each pollutant and the impacts on visibility, plants, soils, and air quality related values of Class I areas, the two facilities must be modeled simultaneously to predict the overall impacts from the Cash Creek source.

Any attempt to model only impacts from the Cash Creek nominal 770 MW facility must be considered circumvention of the PSD permitting regulations and must not be allowed by KDAQ.

Division's response:

> *The Division does not concur that these facilities can be considered a single source under the PSD regulations. The Patriot coal company has four company-operated mines, serviced by three preparation plants in Union and Henderson counties in western Kentucky. The company sold 9.0 million tons of coal in 2006 and controls 866 million tons of reserves in the Illinois Basin. The Division knows of no common control between these two companies, nor would the adjacent mine be considered a support facility.*
>
> *The currently operating mine currently holds a "State-Origin" or minor source permit. Emissions consist almost exclusively as fugitive particulate emissions from the coal transfer operations. Even if the mine could be considered a common source, it would only have a trivial impact on the nearest class I and non-attainment areas.*

8. The emissions from this plant will pollute the surrounding water

Wabash River, IN, is one of the few IGCC plants that has been in operation for a number of years. It is approximately a third the size of the proposed Cash Creek plant. The waste streams from the gasification processes have created significant problems in the nearby water systems there. Operating the gasification process system at Cash Creek is likely to do the same, maybe three times worse, which will threaten the Green River.

The expected waste streams from an IGCC plant include, but are not limited to: un-recycled condensed water from the process, cooling tower blowdown; gasification plant process waste water; regeneration waste water from the demineralizer system in the power block; rainwater collected in the process blocks for both gasification and the power block; and equipment purges (blowdowns) and water wash-downs during maintenance procedures.

Trace elements from the coal feedstock are volatilized in the gasification process, and later condensed from the syngas. The processing of this sour condensate to remove dissolved gases will not remove all trace elements in the processed water stream

The experience at Wabash River indicates elevated levels of selenium, cyanide, and arsenic are to be

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[12] SOB, p.1

[13] According to an IEPA press release for the analogous ERORA Taylorville facility, this plant will consume approximately 1.8 million tons of coal per year. Patriot's three Western Kentucky mines together produced only 4 million tons of coal in 2004. See Peabody Energy Press Release, Nov. 9, 2005, "Patriot Coal Company Earns Reclamation Honors From the Kentucky Department of Natural Resources & Kentucky Coal Association," available at http://phx.corporate-ir.net/phoenix.zhtml?c=129849&p=irol-newsArticle&ID=780974&highlight=. Thus, the Cash Creek facility will require the Patriot mine to potentially more than double its production level, which will in turn significantly impact air emissions.

expected in any of the gasification process water which leaves the plant, as the process wastewater there has routinely exceed permissible daily maximum levels.[14]

Removal of trace elements, such as selenium, arsenic and cyanide can be effectively accomplished through the use of evaporation systems, but such control systems are not mentioned in this permit. If the pollution from the coal gasification process at this plant is to be effectively contained, pollution in the wastewater streams need to be controlled. Otherwise, the future quality of the Green River is seriously threatened by the Cash Creek plant.

Division's response:

> *The Division acknowledges the comment however, discharges into waters of the Commonwealth are regulated pursuant to KPDES permits not Title V/PSD permits.*

9. A Decision To Grant This Permit Must Consider Global Warming Impacts

Carbon dioxide emissions and ensuing global warming effects clearly pose a threat to the health and welfare of humans, animals, and plants, as discussed below. The permit thus must ensure that emissions of carbon dioxide from the proposed facility are adequately controlled to avoid such impacts, under 401 KAR 63:020, "Potentially Hazardous Matter or Toxic Substances." However, neither KDAQ nor the applicant considered the impacts of carbon dioxide from the Cash Creek project. [See Statement of Basis p. 12 of 51, and Application, Section 8].

As the permit states, the proposed project is subject to 401 KAR 63:020, [See Permit p. 2 and 12 of 51], which defines "potentially hazardous matter or toxic substances" as "matter which may be harmful to the health and welfare of humans, animals, and plants, including, but *not limited to*, antimony, arsenic, bismuth, lead, silica, tin, and compounds of such materials." Section 2(2) (emphasis added). According to the American Heritage Dictionary, "matter" is "[s]omething that has mass and exists as a solid, liquid, gas, or plasma."[15] Carbon dioxide clearly fits this definition. Furthermore, there can be no doubt that carbon dioxide emissions and the ensuing acceleration of global warming pose serious danger to humans and the environment. The U.S. EPA has concluded that "[a] few degrees of warming increases the chances of more frequent and severe heat waves, which can cause more heat-related death and illness," as well as "more frequent droughts, ... greater rainfall, and possibl[e] change[s in] the strength of storms."[16] These are only a few of the threats posed by global warming.

The international scientific consensus has indicated that the earth's climate is changing and that human activity is a major factor. [International Panel on Climate Change, *Climate Change 2007: The Physical Science Basis, Summary for Policy Makers*, hereinafter IPCC 2007, available at www.ipcc.ch]. The IPCC 2007 report goes on to note that:

- The global atmospheric concentration of carbon dioxide has increased from a pre-industrial value of about 180 ppm to 279 ppm in 2005.
- The atmospheric concentration of carbon dioxide in 2005 exceeds by far the natural range over the last 650,000 years (180-300 ppm) as determined from ice cores.
- The annual carbon dioxide concentration rate of increase was larger during the last ten years (1995-2005 average: 1.9 ppm) than it has since the beginning of continuous direct atmospheric measurements (1960 – 2005 average: 1.4 ppm per year). IPCC 2007.

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[14] Wabash River Coal Gasification Repowering Project Final Technical Report

[15] "matter." (n.d.). *The American Heritage® Dictionary of the English Language, Fourth Edition*. Retrieved June 08, 2007, from Dictionary.com website: http://dictionary.reference.com/browse/matter

[16] U.S. EPA, climate change website, last updated on April 6, 2001, http://www.epa.gov/globalwarming/faq/fundamentals/html

Fossil fuel burning is the primary contributor to increasing concentrations of CO2 (IPCC 2007).

"Warming of the climate system is now unequivocal." IPCC 2007. Eleven of the past twelve years (1995 – 2006) rank among the 12 warmest years in the instrumental record of global surface temperatures (since 1850). Id.

There can be no doubt that accelerating global warming will pose a serious danger to humans and the environment. Emissions of global warming pollutants have already doubled the risk of extreme heat waves, according to a team of scientists led by Peter Stott at the British MET Office.[17] As the scientific journal *Nature* reported, global warming pollution is linked to the European heat wave of 2003 that killed more than 15,000 people. Similarly, the U.S. EPA concludes that "[a] few degrees of warming increases the chances of more frequent and severe heat waves, which can cause more heat-related death and illness,"[18] as well as "more frequent droughts, ... greater rainfall, and possibl[e] change[s in] the strength of storms."[19] These are only a few of the threats posed by global warming. The IPCC identified the following impacts as either "likely" or "very likely" to occur as CO2 concentrations in the atmosphere increase:

- Higher maximum temperatures over most land areas;
- Higher maximum temperatures and more hot days over nearly all land areas;
- Higher minimum temperatures and fewer cold days and frost days over nearly all land areas;
- Reduced diurnal temperature range over most land areas;
- More intense precipitation events over many areas; and
- Increased summer dry conditions and associated risk of drought over most mid- latitude continents.[20]

The National Academy of Science (NAS) and EPA make similar predictions. [*Climate Change Science*; *CAR*, 106]. The IPCC quantifies these predictions as between 66 and 99% probable, depending on the specific environmental impact.[21] By any measure, global warming will cause serious negative impacts for humans and the environment.

The extent of negative global warming impacts will depend on the amount of CO2 emitted into the atmosphere. The NAS similarly found that the "risk [to human welfare and ecosystems] increases with increases in both the rate and the magnitude of climate change."[22] Simply put, the more CO2 humans release into the atmosphere, the more serious the impacts on the environment.

In 2001, the US Global Change Research Program released *Climate Change Impacts on the United States: The Potential Consequences of Climate Variability and Change,*[23] (*National Assessment Overview*) predicting effects of climate change for each region in the U.S. The report was authored by scientists from the U.S. Geological Survey, USDA Forest Service, and numerous universities across the nation. According to the National Assessment, effects on Kentucky are expected to be significant and severe. Increased average temperatures and increased evaporation are expected, potentially leading to net soil moisture declines. The *National Assessment* shows that "the

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[17] Stott, *et al.*, Human Contribution to the European Heatwave of 2003, *Nature* (432:610), Dec. 2, 2004.

[18] U.S. Environmental Protection Agency, climate change web site, last updated on April 6, 2001, http://www.epa.gov/globalwarming/faq/fundamentals.html.

[19] U.S. Environmental Protection Agency, climate change web site, last updated on April 6, 2001, http://www.epa.gov/globalwarming/faq/moredetail.html.

[20] Third Assessment Report (TAR), *The Scientific Basis*, 15 IPCC 2001.

[21] *TAR: The Scientific Basis*, 2

[22] *CAR*, 254

[23] National Assessment Synthesis Team, Climate Change Impacts on the United States: The Potential Consequences of Climate Variability and Change, US Global Change Research Program, Washington DC, 2000 (National Assessment Overview).

changes in the simulated heat index for the Southeast [including Kentucky] are the most dramatic in the nation." [National Assessment Overview, p. 48]. With the increased heat, air pollution is also likely to worsen.[24] "Without strict attention to regional emissions of air pollutants, the undesirable combination of extreme heat and unhealthy air quality is likely to result." [*National Assessment Overview*, 55]. In other words, harmful air quality will accompany the heat increases predicted for Kentucky as a result of global warming.

These types of weather conditions, which will increase as global warming worsens, have already caused serious health, welfare, and economic problems in the region. For example, "[a] short-term heat wave in July 1995 caused the death of over 4,000 feedlot cattle in Missouri. The severe drought from Fall 1995 through Summer 1996 in the agricultural regions of the southern Great Plains resulted in about $5 billion in damages." *Id.* at 61.

According to the National Assessment, effects on Kentucky, as with the rest of the Southeast, are expected to be significant.in (sic) terms of human health: "of concern...are the effects that elevated surface temperatures have on human health as a result of prolonged or persistent periods of excessive summertime heat events coupled with droughty conditions."[25] Heat is not the only expected cause of health problems in Kentucky's region. Decreases in water quality are also expected, and "effects on surface waters of changes in precipitation have important health implications in the region. Increased precipitation promotes the transportation of bacteria as well as other pathogens and contaminants by surface waters throughout the region." *Id.* at p. 159. Unless releases of global warming pollution are curbed and then significantly decreased, global warming pollution will pose significant threats to the health, welfare, and economy of Kentucky.

Additionally, increases in global temperature may also cause flooding, which poses a direct threat to human health. [*TAR: Impacts*, 762]. Such floods pose a danger due to rising flood waters, but also due to the health threat posed by the agricultural and other non-point source pollution washed into surface water and groundwater supplied during floods. [*National Assessment Overview*, 54].

Kentucky agriculture is particularly sensitive to the degree of warming because of the existing threats of heat waves, flooding and drought. Unless releases of global warming pollution are curbed and then significantly decreased, global warming pollution will pose significant threats to the health, welfare, and economy of Kentucky.

Thus, KDAQ must make an individualized determination as to the proposed project's carbon dioxide emission potential and the adequacy of controls and/or procedures for controlling carbon dioxide pursuant to 401 KAR 63:020. The agency must do its part to prevent these dire health and environmental threats by prohibiting, or at a minimum mitigating, the 3-4,000,000 tons of CO2 pollution that would result from the proposed project annually. (Said another way, this project would add the carbon emissions from adding approximately 500,000 cars per year for each of the next fifty years.)[26]

In light of the serious adverse impacts of carbon dioxide emissions on human health and welfare, property, and the environment, KDAQ cannot lawfully refuse to exercise its authority in 401 KAR 63:020 to eliminate or limit carbon dioxide emissions in taking action on the proposed Cash Creek project permit. Indeed, the Supreme Court in the Massachusetts v. EPA decision makes clear that KDAQ may rely on 401 KAR 63:020 to eliminate or limit carbon dioxide emissions from the Cash Creek permit. [127 S. Ct. at 1455]. The Supreme Court also acknowledged "the enormity of the potential consequences associated with man-made climate change." Id. at 1458.

There are numerous opportunities for mitigating the carbon dioxide emissions associated

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[24] *TAR: Impacts*, 764

[25] *National Assessment* Chapter 5, "Potential Consequences of Climate Variability and Change for the Southeastern United States, p. 146."

[26] See EPA Office of Air and Radiation. Factsheet EPA420-F-00-013 "Average Annual Emissions and Fuel Consumption for Passenger Cars and Light Trucks: Emission Facts."

with the proposed project. First, the project could be designed to expeditiously capture and attempt to store underground in geologic formations a significant portion of the project's proposed CO2 emissions. The current proposal to have the project "capture ready" does nothing to deal with the critical questions facing the entire coal industry – whether large scale carbon sequestration can work, and if coal can have a future in a carbon-constrained world.

As another possibility, this new source of carbon dioxide could be conditioned on the closure of existing sources of carbon dioxide. Third, the project's efficiency (and reduce the need for fossil fuels generally) could be improved by co-locating an industry that could utilize the waste heat/steam, such as a new ethanol or bio-diesel plant.

KYDAQ must consider the global warming impacts from CO2 emissions associated with this proposed project: A) as a non-regulated criteria pollutant in the BACT analysis, and B) in the alternatives analysis under CAA Section 165.

Division's Response:

The Division does not concur. Carbon dioxide in and of itself is not considered a "potentially hazardous matter or toxics substances" under 401 KAR 63:020. BACT analyses are limited to regulated New Source Review pollutants pursuant to 401 KAR 51:001, Section 1 (25). Regarding the commenter's reference to CAA Section 165 (a) (2), no viable alternatives were presented during the public comment period for consideration by the Cabinet.

(a). Carbon Dioxide Must Be Considered In the BACT Collateral Impacts Analysis

Even in the current absence of USEPA regulating carbon dioxide, KYDAQ must still consider carbon dioxide as a non-regulated pollutant in the BACT analysis. This "collateral impacts" analysis is intended to target pollutants that are otherwise unregulated under the PSD provisions.

Division's response:

The Division does not concur. The definition of Best Available Control Technology found at 401 KAR 51:001 Section 1(25) is clear that BACT is required for "each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification... ." Major stationary source and major modification are also clearly defined according to emissions of regulated NSR pollutants for which a NAAQS has been promulgated, pollutants subject to a NSPS under Section 111 of the CAA, Class I and II substances subject to a standard under Section 602 of the CAA, and pollutants otherwise subject to regulation under the CAA. 401 KAR Section 51:001 Section 1(210).

No NAAQS or NSPS has been established for carbon dioxide (CO_2). CO_2 is not a Class I or II substance nor is it otherwise regulated under any provision of the CAA at this time. Therefore, no BACT analysis is required for CO_2 in this permit application and approval. Consideration of environmental impacts, referred to by the commenter as "collateral impacts," is a component of a BACT analysis. Because BACT is not applicable for CO_2, consideration of environmental impacts is also not applicable. Kentucky is required by statute to implement a PSD program that is no more stringent than federal requirements. KRS 224.10-100(26). Where there are no federal regulations establishing requirements for CO_2 at stationary sources, Kentucky is prohibited from imposing any such requirements.

i. A Stringent Output-Based Standard Would Minimize CO2 Emissions

Carbon dioxide emissions are directly related to the amount of coal burned. The more coal (or syngas) burned to produce a megawatt of electricity, the more carbon dioxide emitted. Similarly, the less coal burned the lower the emissions of regulated pollutants.

In the top-down BACT analysis for each regulated pollutant KYDAQ must consider output based limits.

As part of the new NSPS standards USEPA adopted output-based standards as a step towards minimizing inefficient and unnecessarily polluting boilers. In the analysis for the new NSPS standards USEPA identified that boiler efficiency can vary enormously. See Memo from Christian Fellner USEPA to Utility, Industrial and Commercial NSPS File, *Gross Efficiency of New Units* (February 2005). The following table from that same memo and identified as Table 2 describes the range of efficiencies:

USEPA further explained that the highest efficiency subbituminous, bituminous, and lignite facilities are 43, 38, 37 percent efficiencies respectively

In a paper presented by three USEPA combustion experts at the 2005 Pittsburgh Coal Conference they detailed the enormous difference in the efficiency (i.e. the CO2 emissions per ton of coal burned) between sub-critical, super-critical, ultra-supercritical and IGCC coal plants. See Sikander Khan et al, *Environmental Impact Comparisons IGCC vs. PC Plants* (Sept. 2005) (attached). Following is Table 2 from that paper:

To minimize the emissions of carbon dioxide KYDAQ should insert a permit provision requiring the project proponent to maintain a net thermal efficiency at or above 41 percent. Such a term would minimize both the emissions of regulated pollutants and the collateral emissions of carbon dioxide.

Division's Response:

The IGCC process has one of the highest thermal efficiencies of any current coal technology. The Division is unsure if the above quoted figures are current, as it is our understanding that General Electric (GE), the turbine supplier, has made some optimizations and improvements in their designs. The Division does not believe that a thermal efficiency term is appropriate pursuant to the PSD regulations.

ii. Clean Fuels Can Reduce Regulated Pollutants and CO2

Contrary to the plain language of the Act, the agency has not considered clean fuels in its BACT analysis. For some inexplicable reason the agency sets two BACT limits, one for syngas and one for natural gas. If the proposed facility can burn natural gas then it must be considered an available clean fuel in a top-down BACT analysis and may only rejected in favor of syngas in accordance with the procedures detailed in the 1990 NSR Manual. Similarly, there is no discussion of the feasibility of blending biomass into the fuel mix as a way to mitigate the emissions of criteria pollutants and "non-regulated pollutants," such as carbon dioxide. Every increment of additional natural gas or biomass that displaces syngas means less regulated pollutant emissions associated with the burning of syngas and less carbon dioxide emissions.

Division's Response:

See Response to Comment in Attachment C, number 4.d

iii. KYDAQ May Not Increase Emissions of Global Warming

KYDAQ is prohibited from granting this permit without mitigating the global warming impacts because it would allow the project proponent to emit carbon dioxide (and other greenhouse gases such as nitrous oxide) in such quantities that the carbon dioxide emissions and ensuing global warming effects clearly pose a threat to the health and welfare of humans, animals, and plants

Based on the discussion above, carbon dioxide constitutes air pollution and adding more global warming pollution will accelerate global warming and cause further harm human, plant and animal life. KYDAQ may not issue a permit that will cause additional injury to human health and the health of animal and plant life. Further, this is a merchant plant, which has no assigned block of customers dependant on electricity it generates. The CO2 it will generate will create unneeded harm with no countervailing benefit to the Commonwealth.

As demonstrated in the recent Springfield, IL, and Great Plains Energy settlements, it is possible to approve the construction of a new source of carbon dioxide conditioned on achieving overall carbon reductions through strategic investments in the retiring of existing sources, adding clean renewable generation, and boosting spending on energy efficiency measures.

Division's Response:

See Response to Comment in Attachment C, number 9.

(b). KYDAQ Must Consider Global Warming Under the Alternatives Analysis

CAA Section 165(a)(2) provides that a PSD permit may be issued only after an opportunity for a public hearing at which the public can appear and provide comment on the proposed source, including "alternatives thereto" and "other appropriate considerations." 42 U.S.C. § 7475(a)(2).

There are numerous options to building a new coal plant. As the City of Springfield, IL, and Kansas City Power & Light have demonstrated, it is possible to build new coal and through a combination of closing old, inefficient boilers, and investing energy efficiency and clean renewable energy curb overall carbon dioxide emissions.

If KYDAQ does elect to issue this permit, we urge the agency to condition approval of the proposed permit on agreement by the project proponent to curb overall CO2 emissions associated with providing electricity to its customers by 25 percent below 2005 levels by 2012 (i.e. meet the Kyoto Protocol reductions).

Division's Response:

See Response to Comment in Attachment C, number 9. The Division is expressly prohibited from promulgating administrative regulations or imposing permit conditions on the emission of carbon dioxide or other green house gases pursuant to the Kyoto Protocol for the purpose of reducing global warming until authorized by the General Assembly or by federal statute. KRS 224.20-125.

ATTACHMENT D

Response to Comments

Comments on the Draft Title V Air Quality Permit submitted by Board of Commissioners of Warrick County Indiana.

The above referenced comments consisted of the following documents attached hereto as Attachment D-1:

Commissioner's Resolution 2005-08, passed by the Warrick County Commissioner passed on August 10, 2005.
Commissioner's Resolution 2007-05, approved by the Warrick County Commissioner on June 13, 2007.
Letter to Indiana Attorney General, Steve Carter, requesting a Section 126 Petition be prepared against the granting of the Cash Creek Permit.

Division's response:

The Division acknowledges the comments provided in the documents listed above. This permit is being issued pursuant to the applicable laws and regulations. The Division has reviewed the PSD Application from Cash Creek using the EPA recommended review procedures. As long as the proper procedures are followed regarding regulatory applicability and demonstration of compliance, a Title V/ PSD permit must be issued.

Emission limits and control technologies, as established in the permit, are in accordance with all applicable State and Federal requirements including BACT guidelines. AERMOD air dispersion modeling analysis was performed for criteria pollutants (NOx, SO_2, PM_{10} and CO) to determine the maximum ambient concentrations attributable to the proposed plant for each of these pollutants for comparison with National Ambient Air Quality Standards (NAAQS). All The criteria pollutants are modeled to be below the NAAQS.

While the letter to Attorney General Carter is included in the comments as requested by the Board of Commissioners, Attorney General Carter is the appropriate respondent to the letter rather than the Division.

ATTACHMENT E

Response to Comments

Comments on the Draft Title V Air Quality Permit submitted by Newburgh Town Manager and the Town Council of Newburgh, Indiana.

The above referenced comments consisted of the following documents attached hereto as Attachment E-1:

Resolution 2007-08 adopted on June 13, 2007
Resolution 2001-7 dated September 19, 2001
Letter to Indiana Attorney General Steve Carter, requesting a Section 126 Petition be prepared against the granting of the Cash Creek Permit.

Division's response:

See Response to Comment in Attachment D.

ATTACHMENT F

Response to Comments

Comments on the Draft Title V Air Quality Permit submitted by Jonathan Weinzapfel , Mayor of the City of Evansville, Indiana.

1. Require rigorous pollutant control and reduction strategies.
Require coal-fired power plants to utilize the most advanced technologies available to capture carbon and control and/or reduce emission of nitrogen oxides, sulfur dioxides, Volatile Organic Compounds and other pollutants consistent with the implementation of the Clean Air Interstate Rule by 2010, the Clean Air Visibility Rule by 2015, and the Clean Air Mercury Rule by 2020.

Division's Response:

The Division acknowledges the comment. All of the required Best Available Control Technology (BACT) analyses were performed and reviewed for all the emission units. The air quality modeling has shown that this project will not cause nor contribute to any exceedances of any air quality standards. This project will be required to meet the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), and the Clean Air Mercury Rule (CAMR). At this time, carbon capture is not required by state or federal requirements and the Division has no authority to require carbon capture in a permit.

2. Conduct pre-construction and post-construction monitoring data for ozone and PM. This monitoring should encompass at least Henderson and Webster counties in Kentucky and Dubois, Gibson, Pike, Posey, Spencer, Warrick and Vanderburgh counties in Indiana (the Evansville MSA, plus the $PM_{2.5}$ non-attainment counties). It may not be necessary to install and operate new ozone and $PM_{2.5}$ monitors if the U.S. Environmental Protection Agency (EP A) will agree that certain existing monitors will suffice to determine any adverse air quality impacts.

This monitoring should not be limited to the new PSD/NSR sources, but should also be required to include any facility with actual or potential emissions of 100 tons per year of nitrogen oxides, sulfur dioxides and Volatile Organic Compounds.

Division's Response:

The Division does not concur. Preconstruction monitoring is required by regulation for sources that have modeled emissions for criteria pollutants that exceed significant impact levels (SILs). Cash Creek has shown through modeling that their operation will not exceed the SILs and thus preconstruction monitoring is not required. Kentucky maintains an extensive network of ambient air monitors to ensure the protection of the ambient air quality standards, including sites in Daviess, Hancock, Henderson, and Ohio counties. This network is designed and operated in accordance with U.S. EPA requirements. Ambient monitoring in Indiana is under the purview of the Indiana Department of Environmental Management.

3. Perform air quality impact modeling specifically for the above-mentioned counties.
This modeling should take into account the combined estimated emissions from all the proposed facilities with actual or potential emissions of 100 tons/year of nitrogen oxides, sulfur dioxides and Volatile Organic Compounds. This aggregated modeling should be performed in addition to performing modeling for each individual facility. Although modeling is not a perfect science, it is my understanding that it is the best predictive tool available at this time.

Division's Response:

The Division acknowledges the comment. Air quality modeling has been performed pursuant to all applicable requirements including 401 KAR 51:017, Prevention of Significant Deterioration of Air Quality and 40 CFR 51, Appendix W, Guideline on Air Quality Modeling. Modeling for this permit included the area significantly impacted by Cash Creek. All sources that had been permitted or had submitted complete applications prior to the submittal of Cash Creek's complete application were considered.

4. I have long promoted a regional approach to economic development, realizing the benefits of such development reach far beyond the counties involved. However, to promote economic development at the cost of degraded air quality is short-sighted and in no one's best interest. Most major developments will not locate in a non-attainment area, as is evidenced by the number of facilities planned nearby but outside Vanderburgh and Warrick counties. I believe that environmental protection and economic development are not mutually exclusive, but are equally critical to our quality of life and our future.

There is an additional incentive to protect and improve air quality in that the U.S. EP A recently lowered the 24-hour $PM_{2.5}$ standard and is considering lowering the 8-hour ozone standard from 85 ppb to perhaps 70 ppb. If the ozone standard is revised and our air quality does not improve, it is very possible that portions of our Metropolitan Statistical Area, including those counties in Kentucky, may find themselves in the same non-attainment predicament as Dubois, Warrick and Vanderburgh. Future economic development will be stifled and existing facilities within the non-attainment area will find any future projects to be more difficult and expensive.

In conclusion, to merely rely on regulations is to ignore the regional nature of ozone and particulate formation and transport, and the regional nature of our economy. If we hope to see a beautiful, prosperous and healthy home for our children and grandchildren, we must go beyond the regulations and beyond business as usual. We must expect power plants to use the most advanced technologies available to minimize emission of harmful pollutants. Your agency has a critical role to play and I ask that you fulfill your responsibilities in a manner that benefits us all.

Division's Response:

The Division acknowledges the comment. Regional aspects of ozone and fine particulate matter transport are currently being addressed through the NOx SIP Call and will continue to be addressed through CAIR and CAVR. The Division does not have authority to extend requirements beyond promulgated regulations in a permitting action.

ATTACHMENT G

Response to Comments

Comments on the Draft Title V Air Quality Permit submitted by Theodore J. Stransky, M.D to Governor Fletcher.

As you know, we have struggled to keep our air quality in attainment for many years. Even though Cash Creek is supposed to be an environmentally friendly power plant, according to the Evansville Courier, we can expect the following discharges every year:

Total particulate matter 415 tons
Fine particulate matter 68 tons
Sulfur dioxide 391 tons
Nitrogen oxide 704 tons
Volatile organic chemicals 32 tons
Sulfuric acid mist 67 tons

According to the enclosed article from the Evansville Courier of May 23,2007, we are already having ozone alerts and it is only May. How will we handle this added pollution? Will an existing, less environmentally friendly, power plant be shut down? As a physician you, better than most, understand the health effects this will have on the residents of our area and I would hope that would be your primary concern. I would be very interested in hearing your plan to protect our citizens on both sides of the Ohio.

Division's Response:

The Division acknowledges the comment. See Response to Comments in Attachment F, number 3.

ATTACHMENT H

Response to Comments

Comments on the Draft Title V Air Quality Permit submitted by Meleah A. Geertsma, Environmental Law and Policy Center, for the Sierra Club and Valley Watch Inc.

I. IF KDAQ PROCEEDS TO PROCESS THE PROPOSED DRAFT PERMIT, SIGNIFICANT REVISIONS ARE REQUIRED.

a. KDAQ Must Conduct a BACT Analysis for Carbon Dioxide and Set an Emissions Limitation for Carbon Dioxide in the Proposed Permit.

Neither ERORA nor KDAQ addressed the carbon dioxide (CO2) or other greenhouse gases to be emitted from the plant. Yet, the Cash Creek facility will be a significant emitter of greenhouse gas pollutants. Those emissions will contribute significantly to global warming and its adverse impacts on the health, welfare, economy and environment of the State(sic) of Kentucky, as well as the planet as a whole. For these reasons, KDAQ should, and indeed must under the Clean Air Act and Kentucky law, conduct a full BACT analysis for CO_2.

The federal Clean Air Act and Kentucky Air Quality Regulations prohibit the construction of a new major stationary source of air pollutants at the Cash Creek site except in accordance with a prevention of significant deterioration construction permit issued by KDAQ. Clean Air Act § 165(a), 42 U.S.C. § 7475(a); 401 KAR 51:017. KDAQ must conduct a BACT analysis and include in the construction permit BACT emission limitations "for each pollutant subject to regulation under [the Clean Air Act]" for which emissions exceed specified significance levels. Clean Air Act, §§ 165(a), 169,42 U.S.C. §§ 7475(a), 7479; 401 KAR 51:017. In 401 KAR 51 :017, KDAQ adopted, largely verbatim, the Environmental Protection Agency's ("EPA") Prevention of Significant Deterioration regulations set forth at 40 C.F.R. § 52.21. The EPA regulations provide that "[a] new major stationary source shall apply best available control technology <u>for each regulated NSR pollutant</u> that it would have the potential to emit in significant amounts." 40 C.F.R. § 52.21G)(1)(emphasis added); see also 401 KAR 51:017 Section 8. They also define "regulated NSR pollutant" as including "any pollutant. . . subject to regulation under the Act." Specifically, the regulation provides:

> Regulated NSR pollutant, for purposes of this section, means the following:
>
> (i) Any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (e.g., volatile organic compounds are precursors for ozone);
>
> (ii) Any pollutant that is subject to any standard promulgated under Section III of the Act;
>
> (iii) Any Class I or Class II substance subject to a standard promulgated under or established by title VI of the Act; or
>
> (iv) Any pollutant that otherwise is subject to regulation under the Act; except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not been delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

40 C.F.R. § 52.21 (b)(50)(emphasis added); see also 401 KAR 51:001 Section 1(211). The statutory definition of BACT also makes clear that BACT requirements apply to all air pollutants subject to

regulation under the Clean Air Act. The definition states:

> Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

42 U.S.C. 7479(3); see also 40 C.F.R. § 52.21(b)(12), 401 KAR 51:001 Section 1(25). The BACT analysis review that KDAQ must conduct for each pollutant subject to regulation under the Clean Air Act must include a case specific review of relevant energy, environmental and economic considerations that is informed by detailed information submitted by the applicant. See 42 U.S.C. § 7479(3); 40 C.F.R. 52.21(b)(12), (n). Based on its BACT review, KDAQ must set emission limitations in its permit. See 42 U.S.C. § 7479(3) (BACT means "an emission limitation"); 40 C.F.R. 52.21 (b)(12)(same); 401 KAR 51:001 Section 1(25).

It is undisputed that the Cash Creek project is subject to BACT requirements for a number of air pollutants for which emissions will exceed specified significance levels. See Cash Creek Permit Application at 4.1 (Cash Creek will emit PM/PM$_{10}$, SO$_2$, NOx, CO and H$_2$SO$_4$ in significant amounts for PSD/BACT purposes); see also Statement of Basis, Title V Draft Permit, No. V-07-017 (Apr. 30, 2007) at p.14. The proposed new facility clearly will result in carbon dioxide emissions in excess of any applicable BACT significance threshold.[1] See, e.g., Massachusetts Institute of Technology (2007), "The Future of Coal: options for a carbon constrained world," ("M.I.T. Study") at p. 30, Table 3.5 (GE radiant cooled gasifier emits CO2 at a rate of 415,983 kg/hr), Attachment 1.[2]

The proposed permit is subject to BACT requirements for carbon dioxide because carbon dioxide is an "air pollutant" subject to regulation under the Clean Air Act. Section 302(g) of the Clean Air Act defines "air pollutant" expansively to include "any physical, chemical, biological, radioactive . . . substance or matter which is emitted into or otherwise enters into the ambient air." 42 U.S.C. § 7602(g)(emphasis added). In its April 2, 2007 opinion in Massachusetts v. EPA, the Supreme Court held that carbon dioxide and other greenhouse gases are air pollutants as defined in § 302(g), 42 U.S.C. § 7602(g). 127 S. Ct. at 1459-60. The Court based its holding on the "unambiguous" language of the definition. Id. at 1460. The Court further held that because carbon dioxide is within the Clean Air Act's definition of "air pollutant," EPA has the authority to regulate carbon dioxide under the Act. Id. at 1462. The Massachusetts v. EPA decision dispensed with any uncertainty whether carbon dioxide is an "air pollutant" under the Clean Air Act.[3]

Carbon Dioxide is "subject to regulation" under a number of the Clean Air Act's substantive provisions. These provisions include Section 202, which requires standards applicable to emissions of "any air pollutant" from motor vehicles, and Section 111[4], which requires standards of performance for emissions of "air pollutants" from new stationary sources. 42 U.S.C. §§ 7411, 7521. While EPA and the States have not yet established limits under those Clean Air Act provisions, they have the clear statutory authority to do so. Therefore, carbon dioxide is undeniably

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[1] Section 52.21(b)(23)(i), 40 C.F.R., does not set forth a significance level for carbon dioxide. Therefore, pursuant to 40 C.F.R. § 52.21(b)(23)(ii), any emissions of carbon dioxide are significant.

[2] The Attachment consists of Chapter 3, "Coal-based Electricity Generation." The full text report is available at web.mit.edu/coal/The_Future_of_Coal.pdf.

[3] EPA's then general counsel, Jonathan Z. Cannon, opined in 1998 that carbon dioxide is within the Clean Air Act's definition of "air pollutant" and that EPA has the authority to regulate carbon dioxide. More recently, however, EPA has advanced a contrary interpretation that is contrary to the plain language of Section 302(g) and the Massachusetts v. EPA opinion

"subject to regulation" under the Act. The plain meaning of Section 165(a)(4) of the Clean Air Act's mandate that BACT applies to "each pollutant subject to regulation under [the Clean Air Act]" extends not only to air pollutants for which the Act itself or EPA or the States by regulation have imposed requirements, but also to air pollutants for which EPA and the States possess but have not exercised authority to impose such requirements. Regulation under Sections 202 and 111 is required where air pollution "may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. § 7411(b)(1)(A); 42 U.S.C. § 7521(a)(1). The Supreme Court's holding in Massachusetts v. EPA dispensed with any uncertainty whether EPA and the States have the authority to take action to control carbon dioxide emissions under Sections 202 and 111.

The Massachusetts v. EPA case specifically involved a challenge to EPA's failure to prescribe regulations on carbon dioxide emissions from motor vehicles under Section 202 of the Clean Air Act. The Court held that EPA has the authority to issue such regulations, and rejected the excuses advanced by EPA for failing to do so. 127 S. Ct. at 1459-63. Following the Court's decision, the President, in a May 14, 2007 Executive Order, acknowledged EPA's authority to regulate emissions of greenhouse gases, including carbon dioxide from motor vehicles, nonroad vehicles and nonroad engines under the Clean Air Act. The Executive Order directs EPA to coordinate with other federal agencies in undertaking such regulatory action.

Moreover, in addition to being subject to regulation under sections 111 and 202 of the Act, carbon dioxide is currently regulated under Section 821 of the Clean Air Act Amendments of 1990. That section required EPA to promulgate, within 18 months after enactment of the Amendments, regulations to require certain sources, including coal-fired electric generating stations, to monitor carbon dioxide emissions and report monitoring data to EPA. 42 U.S.C. §7651k note. In 1993 EPA promulgated such regulations, which are set forth at 40 C.F.R. Part 75. The regulations generally require monitoring of carbon dioxide emissions through installation, certification, operation and maintenance of a continuous emission monitoring system or an alternative method (40 C.F.R. §§ 75.1(b), 75.10(a)(3)); preparation and maintenance of a monitoring plan (40 C.F.R. § 75.33); maintenance of certain records (40 C.F.R. § 75.57); and reporting of certain information to EPA, including electronic quarterly reports of carbon dioxide emissions data (40 C.F.R. §§ 75.60 – 64). Section 75.5, 40 C.F.R., prohibits operation of an affected source in the absence of compliance with the substantive requirements of Part 75, and provides that a violation of any requirement of Part 75 is a violation of the Clean Air Act.[5]

EPA and the State's regulations cited above echo the mandate of Section 165(a)(4) of the Clean Air Act that BACT applies not only to pollutants for which regulatory requirements have been imposed, but also to air pollutants for which EPA and the States possess but have not exercised authority to impose regulatory requirements.[6] The regulations provide that BACT applies not only to air pollutants for which there are national ambient air quality standards under Section 109 of the Act, standards of performance for new sources under Section 111 of the Act, or standards under or established by Title VI of the Act (relating to acid deposition control), but also to "[a]ny pollutant that is otherwise subject to regulation under the Act." 40 C.F.R. §52.21(b)(50). Carbon dioxide is an

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[4] A challenge to EPA's failure to establish emission limits for carbon dioxide emissions from power plants under Section 111 of the Clean Air Act is pending before the United States Court of Appeals for the District of Columbia Circuit. State of New York, et al. v. EPA, No. 06-1322. EPA refused to establish such emission limits solely on the ground that EPA lacked the authority to regulate carbon dioxide under the Clean Air Act. Based on Massachusetts v. EPA, petitioners, on May 2, 2007, asked the Court of Appeals to vacate EPA's determination that it lacks authority to regulate carbon dioxide emissions under Section 111, and to remand the matter to EPA for further proceedings consistent with the Massachusetts v. EPA decision.

[5] The Kentucky Air Quality Regulations have adopted the carbon dioxide monitoring requirements of 40 C.F.R. Part 75. 401 KAR 52:060 Section 2(d) (Acid Rain Permits); 401 KAR 51:160 (NOx requirements for large utility and industrial boilers); 401 KAR 51:210 and 220 (CAIR NOx trading program).

[6] Indeed, EPA and KDAQ lack the authority to promulgate regulations diluting the mandate of Section 165(a)(4) of the Clean Air Act

air pollutant subject to regulation under the Clean Air Act for which KDAQ must comply with BACT requirements.

The proposed permit for the Cash Creek project does not contain a BACT emissions limitation for carbon dioxide. KDAQ has not conducted a BACT analysis for carbon dioxide. KDAQ has made no effort to identify or evaluate available "production processes or available methods, systems and techniques for control of carbon dioxide." See 40 C.F.R. § 52.21. KDAQ has failed to do so. KDAQ conducted and ERORA in its permit application submitted no BACT analysis for carbon dioxide.

KDAQ's failure to conduct a BACT analysis for carbon dioxide and establish an emission limitation for carbon dioxide must be rectified before KDAQ may lawfully issue a permit for the Cash Creek project. Such analysis must necessarily include all operations planned at the site. It appears that ERORA has not provided KDAQ relevant information as part of its permit application sufficient to allow KDAQ to conduct the required analysis. If KDAQ declines to deny the requested permit at this time, KDAQ should request ERORA to provide it with all information necessary to conduct a BACT analysis for carbon dioxide, conduct the required BACT analysis, and issue a revised proposed permit containing the required carbon dioxide BACT emission limitation.

Division's response:

The Division does not concur. The definition of Best Available Control Technology found at 401 KAR 51:001 Section 1(25) is clear that BACT is required for "each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification… ." Major stationary source and major modification are also clearly defined according to emissions of regulated NSR pollutants for which a NAAQS has been promulgated, pollutants subject to a NSPS under Section 111 of the CAA, Class I and II substances subject to a standard under Section 602 of the CAA, and pollutants otherwise subject to regulation under the CAA. 401 KAR Section 51:001 Section 1(210).

No NAAQS or NSPS has been established for carbon dioxide (CO_2). CO_2 is not a Class I or II substance nor is it otherwise regulated under any provision of the CAA at this time. Therefore, no BACT analysis is required for CO_2 in this permit application and approval. Kentucky is required by statute to implement a PSD program that is no more stringent than federal requirements. KRS 224.10-100(26). Where there are no federal regulations establishing requirements for CO_2 at stationary sources, Kentucky is prohibited from imposing any such requirements.

i. The CO_2 BACT analysis must consider capture and sequestration.

ERORA must evaluate as BACT for Cash Creek add-on technologies to capture and sequester the greenhouse gas emissions. The U.S. Department of Energy is the primary federal agency working on research and development of CO2 capture and sequestration technologies, and thus information on carbon capture and sequestration technologies is available on the U.S. DOE website.[7]

Capture. The International Panel on Climate Change ("IPCC") issued a report in 2005 discussing the main options currently available to capture $CO_2$from fossil fuel-fired power plants, including pre-combustion capture used at IGCC facilities.[8] According to the IPCC, commercial CO_2 capture

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[7] See http://www.fossil.energy.gov /programs/sequestrationl capture/.

[8] 2005 IPCC Special Report on Carbon dioxide Capture and Storage, Technical Summary, at 25. See also Chapter 3 of this report. (Both the Technical Summary and Chapter 3 are included as Attachment 2; entire document is available at http://arch.rivm.nl/env/int/ipcc/pages_medialSRCCSfinalIPCCSpecialReportonCarbondioxideCaptureandStorage.htm).

systems installed on IGCC facilities can reduce CO_2 emissions by 90% per kilowatthour.[9] CO_2 capture systems are available today and have been applied to several small power plants.[10] KDAQ must require ERORA to evaluate the available CO_2 capture systems and to evaluate such CO_2 control systems at the proposed IGCC facility in a proper top-down BACT process focused on maximum reduction of CO_2. ERORA has clearly been evaluating these technologies, as the Cash Creek facility will utilize the Selexol process for sulfur dioxide removal, a process which can also be used to separate carbon dioxide from flue gas. See, e.g., M.LT. study at p. 34.[11]

Sequestration. Nor has ERORA submitted any evaluation of the potential for transporting and sequestering carbon, such as through injection to enhance recovery of oil and gas from sites nearby the proposed Owensboro location or the construction of a pipeline for injection to other appropriate sites.

Division's response:

See response to Comment I. a. above.

ii. The CO_2 BACT analysis must set a stringent output-based standard. Carbon dioxide emissions are directly related to the amount of coal burned. Because electric generating plants are planned and operated to provide a specific amount of electricity, the more coal (or syngas) burned to produce a megawatt of electricity, the more carbon dioxide emitted. Similarly, the less coal burned the lower the emissions of regulated pollutants. In the top-down BACT analysis for each regulated pollutant IEP A must consider output based limits. . In short, more efficiency electrical generation must be considered in a BACT determination because it is a "production process and available method, system and technique... for control of each pollutant." 42 U.S.c. § 7479(3).

As part of the new NSPS standards U.S.EPA adopted output-based standards as a step towards minimizing inefficient and unnecessarily polluting boilers. In the analysis for the new NSPS standards USEPA identified that boiler efficiency can vary enormously.[12] The following table from that same memo and identified as Table 2 describes the range of efficiencies:

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[9] Id. at 107 (Chapter 3).

[10] Id

[11] Both ERORA and KDAQ completely omitted Selexol's significance for capture of carbon dioxide from the Cash Creek BACT analyses. The BACT analyses instead discuss only the process' ability to remove sulfur dioxide as its main function, as well as regeneration of solvent and production of wastewater steam under the heading "Environmental Evaluation." Cash Creek Application at 4.6.8.3

[12] See Memo from Christian Fellner USEPA to Utility, Industrial and Commercial NSPS File, Gross fficiency of New Units (February 2005).

Table 2: EIA 2003 Annual Efficiency Values

Percent of Units Operating at or Above Gross Efficiency	Net Efficiency
Top 10%	35.0%
Top 20%	34.0%
Top 25%	33.6%
Top 33%	33.2%
Top 50%	32.0%

USEPA further explained that the highest efficiency subbituminous, bituminous, and lignite facilities are 43, 38, 37 percent respectively. In a paper presented by three USEP A combustion experts at the 2005 Pittsburgh Coal Conference they detailed the enormous difference in the efficiency (i.e., the CO2 emissions per ton of coal burned) between sub-critical, super-critical, ultra-supercritical and IGCC coal plants.[13] Following is Table 2 from that paper:

To minimize the emissions of carbon dioxide KDAQ should insert a permit provision requiring the project proponent to maintain a net thermal efficiency at or above 41 percent, or set an emission rate limit in pounds per MWh that is based on 41 % efficiency. Such a term would minimize both the emissions of regulated pollutants and the collateral emissions of carbon dioxide.

Division's Response:

The IGCC process has one of the highest thermal efficiencies of any current coal technology. The Division is unsure if the above quoted figures are current, as it is our understanding that General Electric (GE), the turbine supplier, has made some optimizations and improvements in their designs. The Division does not believe that a thermal efficiency permit term or condition is required nor appropriate pursuant to the PSD regulations.

b. The Permit Must Ensure that the Facility Will Not Emit Carbon Dioxide at Such Quantities or Duration as to be Harmful to the Health and Welfare of Humans, Animals and Plants.

Carbon dioxide emissions and ensuing global warming effects clearly pose a threat to the health and welfare of humans, animals, and plants. The permit thus must ensure that emissions of carbon dioxide from the proposed facility are adequately controlled to avoid such impacts, pursuant to 401 KAR 63:020, "Potentially Hazardous Matter or Toxic Substances." Neither the applicant nor KDAQ complied with this requirement by considering the impacts of carbon dioxide from the Cash Creek project. See App. Section 8; Statement of Basis p. 12 of 51.

As the permit states, the proposed project is subject to 401 KAR 63:020. Permit at pp. 2 and 12 of 51. The regulation defines "potentially hazardous matter or toxic substances" as "matter which may be harmful to the health and welfare of humans, animals, and plants, including, but *not limited to,* antimony, arsenic, bismuth, lead, silica, tin, and compounds of such materials." Id. at Section 2(2) (emphasis added). According to the American Heritage Dictionary, "matter" is "[s]omething that

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[13] See Sikander Khan et al, *Environmental Impact Comparisons IGCC vs. PC Plants* (Sept. 2005). Available at: http://cfpub.epa.gov/si/osp_sciencedisplay.cfm?dirEntryID=139864&ActType=project&kwords=Waste

has mass and exists as a solid, liquid, gas, or plasma."[14] Carbon dioxide clearly fits this definition. Furthermore, there can be no doubt that carbon dioxide emissions and the ensuing acceleration of global warming pose serious danger to humans and the environment. The U.S. EPA has concluded that "[a] few degrees of warming increases the chances of more frequent and severe heat waves, which can cause more heat-related death and illness,"[15] as well as "more frequent droughts, ... greater rainfall, and possible changes in the strength of storms."[16] These are only a few of the threats posed by global warming.

The IPCC identifies the following impacts as either "likely" or "very likely" to occur as CO2 concentrations in the atmosphere increase:

- Higher maximum temperatures over most land areas;
- Higher maximum temperatures and more hot days over nearly all land areas;
- Higher minimum temperatures and fewer cold days and frost days over nearly all land areas;
- Reduced diurnal temperature range over most land areas;
- More intense precipitation events over many areas; and
- Increased summer dry conditions and associated risk of drought over most mid latitude continents.[17]

The extent of negative global warming impacts will depend on the amount of CO2 emitted into the atmosphere. However, the fact of those negative impacts is certain. The National Academies of Science, in the report "Climate Change Science" (2001), found that the "risk [to human welfare and ecosystems] increases with increases in both the rate and the magnitude of climate change."[18] Simply put, the more CO2 humans release into the atmosphere, the more serious the impacts on the environment.

In 2001, the U.S. Global Change Research Program released *Climate Change Impacts on the United States: The Potential Consequences of Climate Variability and Change (National Assessment)* predicting effects of climate change for each region in the U.S.[19] The report was authored by scientists from the U.S. Geological Survey, USDA Forest Service, and numerous universities across the nation. The *National Assessment* shows that "the changes in the simulated heat index for the Southeast [including Kentucky] are the most dramatic in the nation." *National Assessment Overview*, p. 48. With the increased heat, air pollution is also likely to worsen.[20] "Without strict attention to regional emissions of air pollutants, the undesirable combination of extreme heat and unhealthy air quality is likely to result." *National Assessment Overview*, p. 55. In other words, harmful air quality will accompany the heat increases predicted for Kentucky as a result of global warming.

According to the National Assessment, effects on Kentucky, as with the rest of the Southeast, are expected to be significant in terms of human health: "of concern.. .are the effects that elevated surface temperatures have on human health as a result of prolonged or persistent periods of excessive summertime heat events coupled with droughty conditions." *National Assessment*, p.

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[14] "matter." (n.d.). *The American Heritage@ Dictionary of the English Language. Fourth Edition.* Retrieved June 08, 2007, from Dictionary.com website: http://dictionary.reference.comlbrowse/matter
Dictionary.com website: http://dictionary.reference.comlbrowse/matter

[15] U.S. EPA, climate change website, last updated on April 6, 2001, http://www.epa.gov/globalwarming/faq/fundamentals/html

[16] U.S. EPA, climate change website, last updated on April 6, 2001, http://www.epa.gov/globalwarming/faq/moredetail/html

[17] International Panel on Climate Change, *Climate Change 2007: The Physical Science Basis. Summary for Policy Makers,* hereinafter IPCC 2007 (attached and available at www.ipcc.ch)

[18] Committee on the Science of Climate Change, National Research Council, "Climate Change Science: An Analysis of Some Key Questions," National Academies Press (200 l)

[19] National Assessment Synthesis Team (2000), available at http://globalchange.gov/pubs/nasC2000.html

[20] IPCC, Third Assessment Report, "Climate Change 2001: Impacts, Adaptation, and Vulnerability," p. 764, available at http://www.grida.no/climate/ipcc_tar/

146.[21] Heat is not the only expected cause of health problems in Kentucky's region. Decreases in water quality are also expected, and "effects on surface waters of changes in precipitation have important health implications in the region. Increased precipitation promotes the transportation of bacteria as well as other pathogens and contaminants by surface waters throughout the region." Id. at p. 159. Unless releases of global warming pollution are curbed and then significantly decreased, global warming pollution will pose significant threats to the health, welfare, and economy of Kentucky.

Thus, KDAQ must make an individualized determination as to the proposed project's carbon dioxide emission potential and the adequacy of controls and/or procedures for controlling carbon dioxide pursuant to 401 KAR 63:020. The agency must do its part to prevent these dire health and environmental threats by prohibiting, or at a minimum mitigating, the 3-4,000,000 tons of CO2 pollution that would result from the proposed project annually. Said another way, this project would add the carbon emissions from adding approximately 500,000 cars per year for each of the next fifty years.[22]

In light of the serious adverse impacts of carbon dioxide emissions on human health and welfare, property, and the environment, KDAQ cannot lawfully refuse to exercise its authority 401 KAR 63:020 to eliminate or limit carbon dioxide emissions in taking action on the proposed Cash Creek project permit. Indeed, the Supreme Court in Massachusetts v. EP A, even without the benefit of the most recent IPCC Reports, noted that the "[t]he harms associated with climate change are serious and well recognized." 127 S. Ct. at 1455. The Supreme Court also acknowledged "the enormity of the potential consequences associated with man-made climate change." Id. at 1458. The Massachusetts v. EPA decision makes clear that KDAQ may rely on 401 KAR 63 :020 to eliminate or limit carbon dioxide emissions from the Cash Creek permit.

Division's Response:

The Division does not concur. Carbon dioxide in and of itself is not considered a "potentially hazardous matter or toxics substances" under 401 KAR 63:020. BACT analyses are limited to regulated New Source Review pollutants pursuant to 401 KAR 51:001, Section1 (25).

c. The BACT Limits are Not Supported.

i. Combustion Turbine versus Gasifier Heat Input

As a general matter, the permit record does not adequately document how the numeric limits were determined. The permit sets limits based on heat input to the combustion turbine. See SOB at Table 4-13; Permit at pp. 3-4 of 51. The application proposes limits based on heat input to the gasifier. App. Section 4. The SOB does not provide any background information on or calculations showing how KDAQ converted the gasifier-heat input limits to combustion turbine heat input limits.

Division's response:

Comment acknowledged. Refer to Cash Creek's November 30, 2006 supplemental submittal attachment 1, Table 4-22, page 4-67 for the applicant's heat input specifications. The Division did not convert gasifier heat input limits to combustion turbine heat input limits. Both specifications are inherent to the process equipment.

ii. Cleaner Fuels.

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[21] Chapter 5, "Potential Consequences of Climate Variability and Change for the Southeastern United States"

[22] See EPA Office of Air and Radiation. Factsheet EPA420-F-00-013 "Average Annual Emissions and Fuel Consumption for Passenger Cars and Light Trucks: Emission Facts.

Cleaner Fuels. BACT explicitly requires a comprehensive analysis of control options that results in "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation [under the PSD program]... achievable for [a] facility through. .*fuel cleaning* [and] *clean fuels.* .." 42 U.S.C. § 7479(3) (emphases added). In other words, "the 1990 Clean Air Act amendments.. .expressly require consideration of clean fuels in selecting BACT" and the EP A considers clean fuels as "an available means of reducing emissions to be considered along with other approaches to identifying BACT level controls." In re: Inter-Power of New York. Inc., 1994 EPA App. LEXIS 33,40,5 E.A.D.130, 134 (E.A.B. 1994)[23]. Longstanding EPA policy with regard to BACT has "required that a permit writer examine the inherent cleanliness of the fuel." Inter-Power at 134. KDAQ's policy likewise is to consider the use of clean fuels in BACT determinations. *See* Andrews Dep. taken in Sierra Club, et al. v. EPPC, File No. DAQ-27602042, Permit No. V-02-043 R2, at pp.39, cited in Petitioners' Memorandum In Support of Motion for Summary Judgment On Counts 2, 4,5, 7, 8, 10, 11, 12, 15, 16, 17, 18,24, and 25, submitted Sept. 1, 2006.[24]

The permit contains separate NOx limits for firing natural gas versus syngas. See below, NOx BACT, for comments on natural gas and NOx BACT.

An available clean fuel that has received no discussion in the agency's top-down BACT analysis is biomass. Co-firing biomass at an IGCC plant can result in lower emissions of NOx, SO_2, and PM/PM_{10}.[25]

There are numerous examples of coal plants co-firing biomass that should be considered in the top-down BACT analysis. For example, the St. Paul heating plant bums approximately sixty percent biomass and forty percent coal.[26] The biomass is primarily waste wood from tree trimmings in the Twin Cities and other industrial activities. The Xcel Bay Point power plant in Ashland, Wisconsin, also bums large amounts of wood waste, consisting primarily of sawdust. Burning biomass also is consistent with Governor Fletcher's recent commitment to expand the use of biofuels.

Cleaner Fuels

The U.S. Department of Energy has urged federal facility managers to consider co-firing up to 20 percent biomass in existing coal-fired boilers.[27] In the Netherlands, the four electricity generation companies (EPON, EPZ, EZH and UNA) have all developed plans to modify their conventional coal fired installations to accommodate woody biomass as a co-fuel.[28] The types of available biomass include wood wastes, agricultural waste, switchgrass and prairie grasses.[29]

Division's response:

The Division does not concur. The IGCC process will use coal to produce synthesis gas (syngas) as the primary fuel (natural gas is a secondary fuel). The facility is specifically designed for synthesis gas as the primary fuel alone and not in combination with natural gas. The lower heating value of biomass has to date precluded its use as a feedstock for gasification. At this time even the use of lignite and subbituminous coals, which have higher

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[23] "The phrase 'clean fuels' was added to the definition of BACT in the 1990 Clean Air Act amendments. EPA described the amendment to add 'clean fuels' to the definition of BACT at the time the Act passed, 'as *** codifying its present practice, which holds that clean fuels are an available means of reducing emissions to be considered along with other

[24] "[fuel cleaning and/or clean fuels are] just part of the BACT analysis."

[25] See, e.g., Tampa Electric Company, "Biomass Test Burn Report Polk Power Station Unit 1," (Apr. 2002) at p. 10 (showing lower NOx and SO_2 emissions for biomass test burn periods versus baseline), available at http://www.treepower.org/cofiring/main.html, As KY measures PM/PM_{10} to include condensable PM, then a reduction in NOX and SO_2 would be a reduction in PM/PM_{10} also.

[26] http://www.districtenergy.com/

[27] http://www1.eere.energy.gov/biomass/pdfs/33811.pdf

[28] http://www.eeci.net/archive/biobase/B10252.html

[29] http://www.nsf.gov/news/news_summ.jsp?cntn_id=108206

heating values than biomass, have presented severe technical problems.

iii. PM BACT

The permit sets a limit for filterable PM/PM_{10} of 0.00851b/MMBtu and a limit for total particulate/PM_{10} of 0.0217 lb/MMBtu. Permit at p. 4 of 51.

Averaging Time. As an initial matter, these limits lack an averaging time. The application proposes a 3 hour averaging time. App. at p. 4-36. This averaging time should be included in the permit.

Division's response:

Comment acknowledged, the averaging time for the PM standards are now included in the permit.

Basis for Total PM/PM_{10} Limit. The proposed filterable PM limit is nearly identical to the filterable PM limit in the final PSD permit for the EKPC Spurlock 4 CFB unit. However, the proposed total PM limit here is higher than the total PM limit for the Spurlock 4 facility (0.012 lb/MMBtu). The applicant does not provide a total PM limit that includes condensable particulate matter, but instead discusses condensable matter from IGCC technology and proposed a method for establishing a total PM_{10} limit based on actual operating data. App. at 4-37. KDAQ included a numeric total particulate/PM_{10} permit limit of 0.0217 Lb/MMBtu[30], but failed to provide the basis for this limit in the Statement of Basis. KDAQ must explain how it determined the *PM/PM_{10}* Total limit.

Division's response:

The Division acknowledges the comment. The basis for the proposed BACT limit is discussed in the supplemental application dated November 30, 2006, Section 4.6.2.5. The Statement of Basis has been expanded to discuss the selection in greater detail.

Combination/Post-Combustion Controls. The PM BACT analysis fails to consider post combustion controls in combination with pre-combustion IGCC wet syngas scrubbing. Contrary to the applicant's assertion, BACT does not automatically allow the rejection of all technologies other than the single control associated with "highest removals" selected by the applicant. *See,* e.g., App. at 4-34 and 4-38. Rather, combinations of controls must be considered. Considering only a single control option is both in conflict with the definition of BACT and with common practice. The definition of BACT uses the plural for control options that must be analyzed towards achieving the "maximum degree of reduction...achievable" (BACT is based on "application of production processes or available methods, systems, and techniques.") Nowhere does the definition of BACT allow the selection of a single control option to the exclusion of all others. Rather, available control options are only rejected in a top-down analysis process. The EAB has held numerous times that BACT must reflect an assessment of all available options to achieve the maximum degree of reduction of each pollutant subject to regulation, and should not be limited to a comparative assessment of add-on controls.[31] In addition, permits in practice set BACT limits based on use of several control options. In fact, the applicant itself proposed, and KDAQ accepted, a NOx BACT limit based on use of combustion control (diluent injection) *and* post-combustion control (SCR). *See* App. at pp. 4-57 to 4-59; SOB at p. 26; Permit at p. 3 of 51.

The applicant mentions several post-combustion PM control technologies, but provides neither technical nor economic reasons justifying why post-combustion PM control in combination with pre-combustion IGCC wet syngas scrubbing does not constitute BACT. KDAQ must deny the permit and request that the applicant provide such justification in a proper top-down BACT analysis or propose new PM limits reflecting the use of

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[30] See, e.g., SOB at p. 19 (discussing *PM/PM_{10}* (filterable) limit of0.0063IbIMMBtu) and 26 *(PM/PMIO* Total limit of 0:0217 lb/MMBtu).

[31] *See* In re Knauf Fiber Glass, Gmbh, 8 E.A.D. 121, 129 (EAB 1999) (Knaufl) (citing NSR Manual at 8.10, 8.13); In re Old Dominion Elec. Coop., 3 E.A.D. 779 (EAB 1992); Inter-Power of New York, 5 E.A.D. at 135-136; In re CertainTeed Corp., 1 E.A.D. 743 (EAB 1982) at 2-5.

post-combustion controls in addition to pre-combustion wet syngas scrubbing.

Division's response:

> *The Division does not concur. The particulate BACT limit for Cash Creek is based on the pre-combustion scrubbing of the synthesis gas. This is an inherent, necessary part of the process because the synthesis fuel must be cleaned before it is combusted in the turbine. The BACT definition specifically allows for the application of production processes. This operational process at 99% removal efficiency is also the most effective form of particulate removal for an IGCC unit and therefore is the "top technology" in a top-down BACT analysis. In accordance with accepted BACT determination procedures, if the top removal technology is selected, no further analysis is required.*

$PM_{2.5}$ BACT. The Draft Permit does not include a BACT limit for $PM_{2.5}$ emissions. Nor does it appear that KDAQ even considered such a limit. This is unlawful and must be corrected before a PSD permit can issue. The federal PSD program requires a BACT limit "for each pollutant subject to regulation under the Act that it would have the potential to emit in significant amounts."40C.F.R. § 52.210)(2). $PM_{2.5}$ is "a pollutant subject to regulation under the Act" because EPA established a NAAQS for $PM_{2.5}$ in 1997.62 Fed. Reg. 38711; 40 C.F.R. § 50.7. Moreover, $PM_{2.5}$ will be emitted from this facility in a "significant" amount because it will be emitted at "any emission rate." 40 C.F.R. § 52.2 1 (b)(23)(ii). For these reasons a BACT limit for $PM_{2.5}$ is required. 42 USC. § 7475(a)(4); 40 C.F.R. § 52.21(j). Nevertheless, the Draft Permit does not contain a BACT limit for $PM_{2.5}$ emissions. This is a deficiency that must be corrected before a final PSD permit can issue.

We are aware that EPA issued guidance providing that sources would be allowed to use implementation of a PM_{10} program as a surrogate for meeting $PM_{2.5}$ NSR requirements. John Seitz, "Interim Implementation for the New Source Review Requirements for $PM_{2.5}$," (October 23, 1997). The purpose of that guidance was to provide time for the development of necessary tools to calculate the emissions of $PM_{2.5}$ and related precursors, adequate modeling techniques to project ambient impacts, and $PM_{2.5}$ monitoring sites. 70 Fed. Reg. 65984, 66043 (Nov. 1,2005). It does not propose, however, to substitute PM_{10} BACT as a $PM_{2.5}$ BACT. Furthermore, EPA has resolved most of the modeling and ambient air impact analysis issues underlying the memo. *Id.* More importantly, the guidance memo clearly contravenes the law. In order to protect public health and the environment, the regulations must be implemented as written.

Division's response:

> *See response in Attachment C, number 4c.*

PM CEMS. The permit is required to have Compliance Assurance Monitoring for PM_{10}, as the facility will emit over 100 tpy pf the pollutant. See 40 CFR Part 64. The draft permit, however, makes no mention of CAM for PM_{10}. This omission must be remedied.

In 2004, EP A promulgated final performance specifications, PS-11, for installation, operation, maintenance, and quality assurance of continuous particulate matter emission monitoring systems (PM-CEMS). Since the PSD program is supposed to be technology forcing, requiring a PM-CEMS to ensure compliance with the PM permit limits would be consistent with that goal. Moreover, utilities can emit large amounts of particulate matter when pollution sources and/or control devices are not functioning properly and PM-CEMS can help identify such compliance issues.[32] KDAQ recently required the use of a PM CEMS in the PSD permit for the EKPC Spurlock 4 CFB project. There is extensive experience of PM CEMS on coal plants as a result of numerous NSR settlements around the country. We urge KDAQ to require the use of a PM CEMS and that a

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[32] *See* USEPA Region 7 Sunflower PSD Comments

PM CEMS is required for determining compliance with the permit's PM filterable limit.

Division's response:

For CAM to apply to a unit, three conditions must be met. The first is that pre controlled emissions are greater than a hundred tons per year, secondly that there is an emission standard, and lastly that there is an active control device used for compliance. For emissions of PM/PM_{10} *the first two conditions are met, but the last one is not. There is no active control device, as defined by 40 CFR Part 64, for* PM/PM_{10}*. Therefore CAM is not required.*

With regard to the PM CEMS, unlike Spurlock 4, the potential for excessive emissions of particulate matter during malfunctions does not exist. Therefore the Division does not concur that a PM CEMS is appropriate.

Bulk Handling, Storage, Processing and Loadout Operations. The top-down BACT analysis must start with the limits that agencies have required in other permits, including the limit of no greater than 0.005 grains/dry standard cubic foot and no visible emissions, based on the permit the Illinois Environmental Protection Agency issued for the proposed Indeck-Elwood facility. See Indeck Permit at p. 27, Attachment 3. In contrast to these acceptable BACT limits, KDAQ failed to include an emission limitation for Unit 7 (coal pile). Permit at p. 25 of 51. Instead, the applicant and agency rely solely on use of certain controls and cite an approximate expected removal efficiency. BACT is an emission limitation. Controls like baghouses and methods such as "compaction" and "water suppression control methods" therefore do not constitute BACT, but are descriptions of how a source might reach a BACT limit. The permit should include numeric limits on material handling emissions like those in Indeck-Elwood. In addition, the permit relies on vague language regarding "reasonable precautions" as operating limitations for Unit 7. Terms such as "reasonable precautions" are unenforceable.[33] See Permit at p. 25 of 51. The emission limitation of 20 percent opacity for Unit 6 is also insufficient in light of the zero visible emissions limit in the Indeck-Elwood Permit. Finally, we were not able to review the emissions modeling for these sources within the limited public comment period. If the modeling did not use the maximum theoretical emission rate for each source, the agency must reject the modeling demonstration and require the applicant to resubmit proper modeling. See NSR Manual at C.4546.

Division's response:

Division does not concur. A BACT analysis is site specific and does not depend on emission levels achieved at another facility. While emission limits at other facilities are a contextual consideration which adds perspective in the consideration of appropriate BACT limits at a new facility, they are not the starting point from which a BACT analysis must begin. A BACT limit is not necessarily a numerical emission limit. Regulation 401 KAR 51:001 Section 1 (25) specifically allows for BACT limits which are ".....satisfied by design, equipment, work practice, or operational standard....." In the case of the referenced coal pile, the Division has determined that ".....technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emission standard infeasible....." as is provided for in the regulation. "Reasonable precautions" is a regulatory term used in regulation 401 KAR 63:010 Section 3. This regulation has been approved to the Kentucky SIP. The opacity limit for Unit 6 is based on 40 CFR 60 Subpart Y which establishes the appropriate opacity limit for this type of equipment.

Cooling Towers. The Draft Permit establishes a limit that requires the cooling tower to "utilize 0.0005% Drift Eliminators." Draft Permit, at 54. This provision is not BACT, and it is not an enforceable emission limit. First, a drift efficiency control rate, by itself, does not correspond to a PM emission rate. PM is formed by dissolved solids in the circulating water. The drift is emitted from the cooling towers, the water is evaporated, leaving the solids that become particulate matter. The percent of the circulating water that is emitted (drift

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[33] See U.S. EPA Region 9, "Title V Permit Review Guideline: Practical Enforceability," (Sept.1999).

rate), by itself, is not a measure of particulate emissions.

Second, an emission rate, calculated from the drift fraction, total dissolved solids ("TDS") and circulating water flow rate, should be established as the permit limit for the cooling tower, based on a topdown BACT analysis. The draft permit sets a drift rate and requires that TDS be measured, but it falls short due to the lack of an emission rate or maximum TDS level in the circulating water flow. While a TDS limit of21,000 parts per million is a start, it is only sufficient as BACT if the ppm concentration is the lowest concentration achievable through application of processes and available methods, systems and techniques for reducing emissions, 42 V.S.C. 7479(3), e.g., purification and filtering of the circulating water. PM emissions from the cooling tower can be further reduced by reducing or eliminating the dissolved solids in the circulating water. Absent a showing that further reduction of solids in the circulating is not technically or economically feasible, the 0.0005% drift efficiency rate and 21,000 ppm TDS limit do not constitute BACT. If KDAQ relies on cooling tower drift eliminators and a limit on suspended solids in the circulating water to establish BACT, the Permit must also include a circulating water flow rate based on the lowest concentration achievable

Third, with regard to testing, the permit must require periodic retesting of drift rates on a more frequent basis than upon permit renewal, as drift eliminator performance degrades over time.

Fourth, a cooling tower with drift eliminators is not the least polluting technology, and does not constitute BACT. Use of an air cooled condenser ("ACC"), an alternative method, system or technique of cooling within the definition of BACT, is available and has lower PM emissions than a cooling tower with drift eliminators. ACCs have been used on large coal-fired power plants for over 25 years. The 330 MW Wyodak coal-fired power plant in Wyoming has successfully operated with an ACC for over 25 years. The largest ACC-equipped coal fired power plant in the world, the 4,000 MW Matimba facility in South Africa, has been operating successfully for over 10 years. Two coal-fired units in Australia with condenser heat rejection rates nearly identical to that proposed for Weston Unit 4 have been operational since 2002. A number of new coal-fired power plants have been proposed in New Mexico over the last three years. In all cases the project proponents have voluntarily incorporated ACC into the plant design to minimize plant water use. A36 MW pulverized coal unit in Iowa, Cedar Falls Utilities Streeter Station Unit 7, was retrofit with dry cooling in 1995 due to highway safety concerns caused by the wet tower plume in winter. The use of dry cooling is well established. The application of an AAC would eliminate nearly all of the PM emissions from the cooling process. Therefore, unless AAC can be rejected in a top-down BACT analysis, based on site-specific collateral impacts, it must be used to establish BACT. AAC cannot be eliminated based on cost, especially because it must be compared to the total cost of a cooling tower, including the towers, raw water clarification system, and intake structures. Moreover, use of AAC has additional environmental benefits, including no water withdrawals for cooling, no brine discharge to river, no aesthetic issues related to visible vapor plumes, no cooling tower drift emissions or particulate deposition.

Other potential options to reduce *PM/PMI0* emissions from the cooling process include a plume abated tower and a wet/dry system. Like ACC, these alternative processes result in lower emissions and, therefore, must be considered in a top-down BACT analysis. The applicant's analysis fails to identify, much less consider these options for reducing PM/PM 10 emissions. A revised BACT analysis must be conducted for the cooling process.

Fifth, the draft permit includes the term "reasonable precautions" as both an operating and an emission limitation. This term is vague and unenforceable. In its stead, the permit should include explicit language describing the measures to be taken with respect to the cooling tower to prevent particulate matter from becoming airborne.

Division's response:

The Division concurs with this comment in part. A calculated pounds per hour emission rate has been added to the permit as a BACT limit. This limit is based on the maximum cooling tower circulating rate, the maximum total dissolved solids, and the 0.0005% drift eliminators. The drift elimination percentage is the best that's available. The maximum *cooling water circulating rate is a function of the facility design. The only one of the factors in the BACT limit that could be changed is the maximum TDS concentration. In response to this comment the applicant provided to the Division on September 28, 2007 (included as Attachment K to this document) an analysis of the cost and technological feasibility of reducing the maximum TDS below 2300 ppm. The analysis showed that further reduction for the TDS is economically unfeasible as BACT. Also, see comment and response number 15 in Attachment A for additional background.*

The Division does not agree with the need to test the drift eliminators periodically through the life of the permit. Proper maintenance and operation of the cooling tower drift eliminators is required for compliance with Section B, Emission Unit 8 Cooling Tower 3. Testing Requirement, and Section E of the permit. Since proper operation and maintenance of the cooling tower is required for proper heat transfer, there is an inherent incentive for the company to comply with these requirements. Since the drift eliminators are fixed mechanisms with no moving parts that require routine maintenance, the Division has concluded that they will continue to function as demonstrated during the initial compliance test for the life of the permit; the drift eliminators will be retested prior to renewal.

The Division does not agree that a dry cooling tower would be the "top" candidate for a BACT review. The wet cooling tower is the emission unit chosen by the applicant. The drift eliminators, selected as BACT by the Division, are the top control technology available for cooling towers of this type. ACC is not a control device for wet cooling towers. It is an alternate to wet cooling towers. Wet/dry systems and plume abated towers are also alternative emission units, not control devices for the selected wet cooling tower. At the permitted emission limit of 2.16 lbs/hr emitted from the cooling tower, the total particulate emission is less than 9.4 tons/yr.

The term "reasonable precautions" is the language of the regulation found at 401 KAR 63:010. Consistent with 401 KAR 51:017 the permit contains conditions which require the unit to be maintained and operated properly.

iv. NOx BACT

The permit sets limits for NOx of (a) 0.0331lb/MMBtu during any rolling three-hour average when firing syngas, and (b) 0.0246 lb/MMBtu during any rolling three-hour average period when firing natural gas.

Fuel-based limits. While the permit sets two different limits for syngas and natural gas, the applicant proposed a single NOx limit of 0.0246lb/MMBtu for both fuels. The SOB does not explain the agency's decision to set two different limits when the applicant proposed a single limit for both fuels. While the applicant included a footnote to its proposed NOx limit, the application available for public review did not contain any text for this footnote. See App. p. 4-59 (footnote 35 empty). Absent any justification for treating the two fuels differently, BACT for NOx should be the single numeric limit for both fuels proposed by the applicant.

Furthermore, as noted above, a top-down BACT analysis must consider the use of cleaner fuels, including natural gas and biomass. Since the facility is specifically designed to be able to fire natural gas, burning gas would not "redefine the source." The limit for firing natural gas is lower than that for syngas. In addition, as noted above, co-firing biomass at an IGCC facility is technically feasible and results in lower NOx emissions than firing syngas alone. Thus, NOx BACT must be based on consideration of firing natural gas and biomass. The facility also is designed to burn natural gas in combination with syngas. By burning a mix of natural gas with syngas, or 100% natural gas, the source could lower both the pound-per-MMBtu emission rate and the hourly emission rate for each of the regulated pollutants, including NOx. Thus the BACT analysis must consider mixing natural gas with syngas and burning 100% natural gas. If the cost effectiveness of combusting natural gas, or a combination of gas and syngas, is within the range generally accepted as cost-effective for similar sources (i.e., under $10,000 per ton of pollutant removed), the BACT limit for NOx must be established based on a BACT analysis that factors in natural gas. Notably, burning 100% natural gas could allow the source to avoid purchasing some of the most expensive equipment, including the gasifier.

Lower NOx limit. Furthermore, while we commend ERORA for analyzing and selecting Selective Catalytic Reduction ("SCR") in its NOx BACT analysis, the proposed technology can achieve lower than the proposed permit limits of0.0331lb/MMBtu and 0.0246 lb/MMBtu. The applicant states that the "most stringent [NOx] emission limit" for existing and proposed IGCC sources is 0.0591b/MMBtu from the Southern Illinois Clean Energy Center facility. App. at 430. The cited facility will not employ SCR, a post-combustion control, to limit NOx emissions. SICEC therefore represents the "uncontrolled" emissions baseline for purposes of assessing SCR for an IGCC facility. The applicant acknowledges that SCR alone can achieve 90% "add-on" control efficiency for NOx. App. at 4-57. Given an uncontrolled baseline of 0.059 lb/MMBtu NOx and an add-on control efficiency of 90% for SCR, the NOx BACT limit for Cash Creek should be 0.0059Ib/MMBtu.

Division's response:

> *The original application had the single limit however, that submission was erroneous. A later supplemental submission provided to the Division the justification for two separate emission rates depending on fuel type. That supplemental submission was available for public review during the public comment period. Also, see response to Attachment C (4)a.*
>
> *The Division does not concur with the comment that suggests that BACT must consider the use of natural gas and biomass. The unit was designed to burn only syngas with natural gas as a secondary fuel. See also the response to Attachment C comment 4.d. Further, the faculty is not designed to burn natural gas in combination with synthesis gas.*
>
> *The Division does not concur that the Southern Illinois Clean Energy Center should be considered the ultimate baseline in determining uncontrolled NOx emission rate. This facility's application was withdrawn without a permit ever being issued. Since it was neither permitted nor built, it is impossible to determine whether any limit proposed for that facility is applicable, or could be achieved in practice.*

v. Sulfur dioxide (SO2) and sulfuric acid mist ("SAM") BACT

The applicant asserts that a single analysis is required to determine BACT for SO2, SAM and condensable PM. App. at p. 4-42.

BACT requires a separate analysis for each regulated pollutant. First, the applicant is incorrect as a legal matter. BACT is an "emission limitation" that is determined on a "case-by-case basis" for "each pollutant subject to regulation under Act." 40 C.F.R. 52.21(b)(12). Thus, while there may be overlap in the "control devices" discussed in the BACT analysis for each pollutant (see App. at 4-42), separate BACT analyses must be conducted to arrive at proper emission limitations. Separate analysis is necessary to take into account the chemical and physical differences among the pollutants. Absent separate analyses for each pollutant, the BACT limits are not supported. As the Applicant's BACT analysis for SO2 and SAM directly discusses only "BACT Selection for SO2,"App. at pp. 4-45 to 4-56, the BACT analysis for SAM is insufficient.

A single BACT analysis for SO2 and SAM is technically unjustified. Second, as a technical matter, the applicant's combined SO2-SAM BACT analysis fails to explain why a combined analysis is justified in light of the limits proposed for the Elm Road facility. The application sites Elm Road as having the most stringent existing or proposed limit for SAM, at 0.00005 Ib/MMBtu (note that we believe this limit should be 0.0005 IbIMMBtu). App. at 4-30. The accompanying SO2 limit proposed for Elm Road was 0.03 Ib/MMBtu. The H2SO4 and SO2 BACT limits proposed by the applicant for Cash Creek are 0.0026 IbIMMBtu and 0.0117 Ib/MMBtu, respectively. Given that the Elm Road project has a lower SAM but a higher SO2 limit than the limits proposed for Cash Creek, it is not clear that a single BACT analysis is technically appropriate for the two pollutants.

For comments on the condensable PM, see above.

Division's response:

> *Regulation 401 KAR 51:001 Section 1 (25) defines BACT as "……an emission limitation, including a visible emission standard, based on the maximum degree of reduction of each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification that: (a) is determined by the Cabinet on a case-by-case basis after taking into account energy, environmental, and economic impacts and other costs, to be achievable by the source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of that pollutant………"*
>
> *Sulfur is the basic common "building block" for SO_2, SAM, and the bulk of condensable particulate. In the case of an IGCC facility such as Cash Creek, sulfur must be removed from the syngas prior to combustion to protect the combustion turbine. Since BACT can be achieved by application of production processes, pre-combustion removal of the sulfur from the syngas qualifies as a single control technology for all three (SO_2, SAM, and condensable particulate) pollutants. By reducing the pre-combustion sulfur content, SO_2, SAM, and condensable particulate are reduced proportionately. Therefore it is appropriate to consider pre-combustion sulfur removal as a BACT technology for all three pollutants. The Cash Creek application dated December 4, 2006, gives a detailed technology and cost analysis supporting their selection of the Selexol chemical process for the removal of sulfur prior to combustion. (See pages 4-46 through 4-57.) As Cash Creek notes in their application on page 4-44, "Since the highest removals available are associated with pre-combustion controls, the post-combustion technologies are not considered further in this BACT analysis." This is a valid reason to eliminate post combustion controls because a sulfur removal efficiency of 99.4% is expected with the Selexol process. Since no post-combustion control device can achieve that level of removal efficiency, the Selexol process is the correct choice as BACT for all three pollutants.*

1. SO2 BACT

Clean fuels. The SO2 limit consists of a limit on the exhaust gas based on syngas fuel not to exceed 0.8 percent sulfur by weight. There does not appear to be any clean fuel consideration applied to this standard, For example, as described above in the PM BACT discussion, there does not appear to have been any consideration of the use of natural gas and/or biomass either in whole or in part as a clean fuel control method to minimize the emissions of criteria pollutants, including sulfur dioxide. The SO2 top-down BACT determination for the combustion turbines must include consideration of natural gas and gasified biomass.

Division's response:

> *The faculty is not design to burn biomass but syngas and natural gas used as a secondary fuel. See response to Attachment C(4)d and Attachment H, NOx BACT.*

2. SAM BACT

The Draft Permit contains a SAM limit of 0.0026 lb/MMBtu. Permit at p. 4 of 51. As an initial matter, the limit lacks an averaging time. The application proposes a three-hour rolling average. Application at 4-56. In addition, this purported BACT limit appears high. As noted above, the application lists the Elm Road facility as having the most stringent existing or proposed limit for SAM, at 0.00005 lb/MMBtu (0.0005 lb/MMBtu).

The application provides no justification why this limit cannot be achieved at Cash Creek. In addition, in 2002, the AES Puerto Rico permit for a coal-fired CFB plant had a SAM emission limit of 0.0024lb/MMBtu, which is lower than the proposed limit for Cash Creek. This facility will include a Wet Electrostatic Precipitator ("WESP") to control particulate matter; SOB at 16, similar to the Trimble facility recently proposed by Louisville Gas & Electric However, the SOB only lists the WESP under control technology for PM/PMI0. Id. We urge KDAQ to consider a lower SAM limit based on the use of a WESP in a top-down BACT determination for Cash Creek. As put forth above, BACT requires consideration of combinations of controls, including pre- and post-combustion controls. The use of WESPs are now common on new coal plants burning high-sulfur coal (see e.g., the Trimble facility and the Prairie State facility in Illinois) and we are not aware of any obvious technical reasons why a WESP could not be used on an IGCC plant as well.

Division's response:

> *A three hour rolling average for SAM has been added to the permit. With regard to the emission limit, the Elm Road facility is a CFB, not a gasifier, and is not an appropriate 'like facility' for consideration of appropriate emissions from Cash Creek. The commentor is correct that the use of WESPs are now common on new coal plants burning high-sulfur coal. However, while a WESP is appropriate for control of SAM from a high sulfur coal PC or SPC facility, it is not appropriate for a gasifier where the bulk of the sulfur is removed prior to combustion. Cash Creek is designed as a combined cycle steam turbine, similar to a standard combined cycle steam turbine that burns natural gas. Both Cash Creek and natural gas burning combined cycle steam turbines have very low sulfur fuel. The Division is unaware of any combined cycle steam turbine that is operating, permitted or designed with a WESP. Given the low sulfur content of the fuel and the limited amount of SAM emitted, the Division does not believe that a reasonable engineering analysis would compare the SAM emissions from a PC unit with a combined cycle gas turbine (CCGT).*

vi. Visible Emissions

The permit contains an opacity limit of 20%, except that a maximum of twenty-seven percent for not more than I six-minute per hour. Condition B.2(d).

This emissions limit is based on the NSPS standard, and not on BACT level control. Id. (citing 40 CFR 60.42Da (b)). The Draft Permit is therefore deficient. The permit must contain a visible emission limit for regulated pollutants (i.e., PM and H2SO4)[34] that is based on the maximum degree of reduction achievable with the best pollution control option for the proposed facility. A PSD permit must require BACT for all regulated pollutants. BACT is defined as an "emissions limitation, *including a visible emission standard...*" 42 U.S.C. § 7479(3) (emphasis added); 40 C.F.R. § 52.21(b)(12). Although a BACT limit for PM or SAM typically includes an emission rate limit (i.e., pounds per hour or pounds per million Btu heat input), a BACT limit must nevertheless also "includ(e] a visible emission standard." Id.

Other recent coal plant permits include visible emission as part of the BACT limits for those facilities. For example, the Springerville facility in Arizona has a BACT limit of 15% opacity, and the Mid-America facility in Council Bluffs has an opacity limit of 5 percent.. 35[35] The Wisconsin Department of Natural Resources set a 10% opacity limit as BACT for the Fort Howard (Fort James) Paper Company's 500 MW CFB boiler. The Minnesota Pollution Control Board also considered the issue and determined that a 5% opacity limit should

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[34] A visible emission standard is a limit on "light scattering particles," which include both fine particulate matter ("PM") and sulfuric acid mist ("SAM") aerosols. Both PM and SAM are regulated under PSD and, therefore, a complete PSD permit must contain a BACT limit which includes a visible emission limit based on BACT for PM and SAM.

[35] See Iowa DNR Permit No. 03-A-425-P, § 10a, available online at http://aq48.dnraq.state.ia.us:8080/psd/780 1 026/PSD _PN_02-258/03-A-425-P-Final.pdf, last visited October 28, 2005

be established based on BACT. The maximum achievable visible emission reduction for a combustion turbine, however, is much lower than 20% opacity. For example, the JEA Northside CFB in Jacksonville, Florida, conducted a compliance test during the summer of 2002, while burning high-sulfur coal, and measured opacity of less than 2%.[36] Testing done by Black & Veatch for the Department of Energy showed visible emissions at the JEA facility of 1.1 % and 1.0% opacity.[37] Also, the City of Springfield agreed to a lower opacity limit.

The final permit must contain BACT limits that include a visible emission standard for the combustion turbines. The BACT limits for PM and SAM must include a visible emission limit of no more than 2% opacity based on the results of testing at the JEA Northside facility.[38] In other words, if opacity at a CFB plant can be limited to less than 2 percent opacity, the project applicant must explain why it cannot meet such a limit when firing syngas, a fuel with lower particulate matter emissions than solid coal.

Division's response:

The Division does not concur. Opacity is not a regulated NSR pollutant under state or Federal requirements.

The actual regulatory citation for BACT under Kentucky regulations comes from 401 KAR 51:001 Section 1(25)

(25) "Best available control technology" or "BACT" means an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification that:...

210) "Regulated NSR pollutant" means the following:

(a) A pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the U.S. EPA;

(b) A pollutant that is subject to any standard promulgated under 41 U.S.C. 7411;

(c) A pollutant that is subject to a standard promulgated under or established by 42 U.S.C. 7671 to 7671q; or

(d) A pollutant that otherwise is subject to regulation under 42 U.S.C. 7401 to 7671q, except that any hazardous air pollutant (HAP) listed in 42 U.S.C. 7412 or added to the list pursuant to 42 U.S.C. 7412(b)(2), which has not been delisted pursuant to 42 U.S.C. 7412(b)(3), is not a regulated NSR pollutant unless the listed HAP is also regulated as a constituent or precursor of a general pollutant listed under 42 U.S.C. 7408.

From 401 KAR 51:001

Section 1 (7) "Air pollutant" means air contaminant.

KRS 224.01-010 Definitions for chapter.
As used in this chapter unless the context clearly indicates otherwise:

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[36] William Goodrich, et al., Summary of Air Emissions from the First Year Operation of JEA's Northside Generating Station, Presented at ICAC Forum '03, p. 16

[37] See Black & Veatch, Fuel Capability Demonstration Test Report 1 for the JEA Large-Scale CFB Combustion Demonstration Project, DOE Issue Rev. 1 p. 12 (Sept. 3,2004)

[38] See Goodrich, *supra*, p. 16

(1) "Air contaminant" includes smoke, dust, soot, grime, carbon, or any other particulate matter, radioactive matter, noxious acids, fumes, gases, odor, vapor, or any combination thereof;

There is neither a federal requirement nor a state requirement to have an opacity limit other than that contained in the applicable regulations. Attempting to assign a BACT limit for opacity would require the state PSD program to be more stringent than the federal requirements. Opacity may be an indicator of particulate matter, fumes, gases or vapor, but it is not an independent pollutant to be regulated under the PSD program. Opacity is the property for the absorption of light, an appropriate indicator for a variety of air pollution concerns, but not a regulated NSR pollutant.

vii. Startup, Shutdown, and Malfunction BACT

1. Sulfur Recovery Unit

The draft permit completely exempts the sulfur recovery unit from its limit of 100 ppm by volume (dry basis) at 0% oxygen on a three hour basis during periods of startup and shutdown. Permit at p. 17 of 51. There are no obvious reasons why the permit could not require the use of natural gas during periods of startup and shutdown of the sulfur recovery unit and thereby avoid the firing of high-sulfur syngas during these periods. Accordingly, the use of natural gas must be considered in setting a top-down SO_2 BACT limits for the sulfur recovery unit during periods of start up and shutdown. The existing limit does not constitute BACT.

Division's response:

The Division is unclear on the commenter's intent. The sulfur recovery unit does not burn fuel (either synthesis gas or natural gas), nor does the combustion turbine burn 'high-sulfur syngas' during periods where the sulfur recovery unit is being started up or shut down.

2. Combustion Turbines

The draft permit does not appear to have any meaningful start up or shutdown limits for the combustion turbines for any pollutants. The permit as written exempts periods of start up and shutdown from any input-based limits for PM (both filterable and total), NOx and mercury[39], and SO2[40]. The only other applicable limits to these pollutants appear to be the annual limits.

Annual limits are not sufficient to meet the requirement that a PSD permit include BACT startup and shutdown limits for each regulated pollutant and protect air quality standards. See *In re Indeck-Elwood, LLC,* PSD Appeal No. 03-04 (EAB September 27,2006).[41] In setting lawful startup and shutdown BACT limits KDAQ must consider the use of cleaner fuels, *i.e.* other than syngas, such as natural gas and/or gasified biomass. If KDAQ issues a new permit with numeric startup and shutdown BACT limits for each regulated pollutant - as we believe it must -- the public must get an opportunity to comment on such new limits prior to their being finalized.

The permit also refers to a startup-shutdown plan submitted to the agency. Permit at p. 4 of 51. It is not clear whether this plan was made available to the public as part of the permit record. As commenters have not reviewed the plan, it is assumed that the plan contains so-called "narrative" limits to allegedly serve as BACT. Narrative limits are allowed to serve as BACT only where the agency determines on the record 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." 401 KAR 51:001 Sec. 1(25)(c); 40 C.F.R. § 51.166(b)(12); *In re Indeck-Elwood, LLC,* PSD Appeal No. 03-04 (EAB September 27, 2006)("Indeck-Elwood"). If such a standard is set as BACT, the standard must establish "the emissions reduction achievable by implementation of the design, equipment, work practice or operation." Id. Narrative limits, in contrast, are not permitted where the limitations cited by the agency are principally design and operational constraints, such as the inability of air pollution control technology to operate at low temperatures during startup and shutdown. *Indeck-Elwood* at p. 70. Thus, KDAQ must make an on the record determination that these standards are met in order for the startup shutdown plan to properly serve as BACT, as well as set the accompanying emissions reduction achieveable for each pollutant under the narrative limits. Absent such justification, KDAQ must set numeric BACT limits for all regulated NSR pollutants. In addition, as a critical part of the permit's narrative limits for startup and shutdown, the plan should be attached to the permit and incorporated by reference as an enforceable component of the permit itself.

In addition, Section E contains a catchall "good practices" provision that applies during all operations, including periods of startup and shutdown. Permit at p. 37 of 51. The condition states that "Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source." As the determination will be based on "information available to the Division" that is not available to the public, the condition is unenforceable by the public and thus is in violation of Title V requirements.

Division's response:

> *The Commenter is in error. The permit conditions only reference, 40 CFR 60 Subpart Da which exempts the source from compliance with this NSPS standards during defined periods, there is no corresponding language in this permit that the source be exempted from BACT requirements. The permittee may follow the provisions in 401 KAR 50:055 if they are*

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[39] Section B Units 01 and 02, Condition 2(h)

[40] Section B Units Ol and 02, Condition 4(b) - periods of startup and shutdown excluded from 3-hour rolling average exceedances; Section B Unit 05, Condition 2(c).

[41] Deciding whether exemption from *short-term* BACT limits and inclusion of vague, to-be-determined narrative limits comply with BACT. The starting point for the EAB's decision was the statutory and regulatory definition of BACT. Under the definition, BACT requirements cannot be "waived or otherwise ignored during periods of startup and shutdowns." *Indeck-EZwood* at p. 66.

seeking relief during periods of startup, shutdowns and malfunctions; otherwise, they must comply with the BACT limits.

The Start-up, Shutdown, and Malfunction (SSM) plan was submitted in the supplemental application dated December 4, 2006. This supplemental application was available for public review during the public comment period. The SSM does not contain 'narrative limits'; BACT limits are in force during these periods.

The information to which Section E refers will be available to the Division only after the facility is built and is in operation. At that time, all information that the Division considers in making any determination regarding acceptable operating and maintenance procedures will also be available to the public through the Kentucky Open Records Act.

3. Terms Should Be Clearly Defined

The term "startup" should be defined as "the period beginning with ignition and lasting until the equipment has reached a continuous operating level and operating permit limits.[42] The term "shutdown" should be defined as "the period beginning with the lowering of equipment from base load and lasting until fuel is no longer added to the combustion turbine and combustion has ceased.[43]

Division's response:

Startup and shutdown are regulatory terms. These terms cannot be redefined in a permit.

II. THE PERMIT CONTAINS PROVISIONS THAT ARE NOT ENFORCEABLE

a. Continuous compliance.

Conditions throughout the permit fail to state that continuous monitoring systems will only be used as "the indicator of continuous compliance" and that exceedances of limits as measured by the systems will only trigger an investigation. See, e.g., Condition *BA(b).* These conditions render the CAM provisions inadequate to ensure continuous compliance with permit limits. The EPA has objected to Title V permits in Region 4 for failure to include explicit statements that the indicators are not set as enforceable limits. For example, in the Tampa Electric Company's F.J. Gannon Station case, the EPA objected to the Title V permit, stating:

> While the permit does include parametric monitoring of emission unit and control equipment operation in the O&M plans for these units... the parametric monitoring scheme that been specified is not adequate. The parameters to be monitored and the frequency of monitoring have been specified in the permit, *but the parameters have not been set as enforceable limits. In order to make the parametric monitoring conditions enforceable, a correlation needs to be developed between the control equipment parameter(s) to be monitored and the pollutant emission levels* [44]

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[42] 401 KAR 52:001 contains a more general definition of start-up, "setting in operation of an affected facility." 401 KAR 52:001 (231) This definition is unenforceably vague and should be supplemented by additional permit language.

[43] Likewise, Kentucky regulations define shutdown as "the cessation of an operation," which also should be supplemented by enforceable permit language.

[44] U.S. EPA Region 4 Objection, Proposed Part 70 Operating Permit, Tampa Electric Company, F.J. Gannon Station, Permit No. 0570040-002-A V

The Permit must explicitly state that an exceedance of an indicator is a violation of the underlying applicable requirement; otherwise, the indicator does not assure that the underlying requirement is enforceable,

Division's response:

> *The commenter has misstated U. S. EPA's current policy regarding the use of parametric monitoring by citing a dated and inappropriate permit objection. Enforceable emission limits are set in the permit, and exceedance of a CAM level is not a permit violation, but rather a trigger for corrective actions under the CAM rule. This permit is being issued in accordance with Kentucky regulations and laws and is consistent with current U.S. EPA guidance and policy.*

b. Vague and ambiguous language.

As discussed above with respect to specific permit conditions, the Permit contains numerous words and phrases that are vague and thus unenforceable. These words and phrases include "reasonable precautions," "clean", "as applicable", "suitable", "other measures", "prompt", and "as necessary." The U.S. EPA has made clear that these terms render conditions practicably unenforceable. U.S. EPA Region 9, "Title V Permit Review Guidelines: Practical Enforceability," Sept. 9 1999, at III-55 and 61 ("It is also important that permit conditions be unambiguous and do not contain language which may intentionally or unintentionally prevent enforcement"; listing language indicating enforceability problems and instructing use of specific language). The permit must be amended to include numeric limits or specific actions with which the source must comply for conditions containing vague and ambiguous language. These conditions include, but are not limited to, Unit 07 (coal handling), Condition l(a); Unit 08 (cooling tower), Condition l(a); and Unit 10 (roadways), Condition l(a).

Division's response:

> *The words and phrases that the commenter calls "vague" and "unenforceable" have been reviewed and upheld as adequate in permits and legal challenges and are, in fact, in some cases language of the regulations. The permit is required to be "enforceable as a practical matter" which is defined in 401 KAR 52:001 Section 1 (31). The permit contains all the requirements necessary to meet this definition. The places in the permit where such terms as "reasonable precautions," "clean", "as applicable", "suitable", "other measures", "prompt", and "as necessary" are not intended to be emission limits, but rather are indicators of actions that the permittee should take to ensure that the limits are met. They are used to provide the Division with some discretion in determining whether or not adequate steps have been taken by the permittee to ensure compliance.*

III. THE APPLICANT FAILED TO DEMONSTRATE THAT THE FACILITY WILL NOT CAUSE OR CONTRIBUTE TO A VIOLATION OF AIR QUALITY STANDARDS

a. Emissions inventories

The applicant requested a listing of all sources located within 100 kilometers of Cash Creek to determine the emissions inventory for air quality modeling. App. p. 6-16. It is not clear from this discussion whether permitted but not yet operating facilities were included in the inventory. Further, ERORA also should have included the projected emissions of sources which have been issued PSD permits but which are not yet operating.[45] For example, ERORA should have included the maximum allowable emission rates of LG&E's Trimble County unit currently under construction, and the maximum allowable short term average emission rates must be evaluated in determining compliance with short-term average standards or increments. KDAQ should confirm whether such facilities were included and if they were not, deny the permit and require the applicant to resubmit the air quality analysis with the expanded inventory.

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[45] *see* page C.34 of the New Source Review Workshop Manual.

In addition, there are clearly sources that will likely have a significant concentration gradient in the vicinity of Cash Creek that should be included in Class II increment and NAAQS modeling. These include but are not limited to the nation's largest coal plant, Duke's Gibson station (3350 MW), the TVA Paradise station in Muhlenberg County (2650 MW), the Big Rivers Coleman plant, the Southwire aluminum plant located in Hancock County, the Waupaca Foundry in Perry County, IN, and the AK Steel plant in Rockport.

Also, there are several ethanol plants and at least one biodiesel plant in the region that should have been included in the inventory but were not. There are at least two ethanol plants planned for Henderson County and a biodiesel plant proposed for Daviess County. In Indiana, there are three (at least one has secured a permit) in Posey County, one in Spencer County and one in Pike County that should be included in the analysis. ERORA also should have included emissions from oil and gas wells in the vicinity of the project. The mobile source and fugitive emissions associated with the roads for oil and gas development must also be included in the inventory of sources for a cumulative analysis.

Thus, KDAQ cannot adequately assess whether the Cash Creek source will cause or contribute to a violation of the NAAQS or Class II increments based on the analysis provided in the Cash Creek permit application. KDAQ must require ERORA to conduct a complete NAAQS and Class II increment by modeling the Patriot mine together as one source and by requiring the emissions inventory for the cumulative NAAQS and Class II increment analyses to be expanded to include all of the above sources and any other sources of air pollution, including minor and area sources, within the vicinity of the Cash Creek source. Also, it is not clear that all required sources were included in the increment consumption modeling. Sources that consume increment are: (1) the applicant source, (2) all increases since the minor source baseline date (the date of the first complete PSD application), and (3) all significant increases at major sources, after the major source baseline date (1975)-- i.e., major modifications subject to PSD/NSR-- even those that should have but did not get a permit. Typically, applicants only look at the first two. KDAQ should confirm that the source did not omit any unpermitted modifications at any nearby sources since 1975 from the increment analysis. If any modified, unpermitted sources were omitted, KDAQ should return the application to ERORA for proper increment modeling.

Division's response:

Cash Creek submitted an air quality impact assessment following the requirements of 40 CFR Part 51 Appendix W, Guidance on Air Quality Models. This analysis was reviewed and approved by KDAQ, National Park Service, and U. S. EPA Region 4. As a part of that analysis the Significant Impact Area (SIA) was determined and all sources within the SIA plus 50 km were either included or eliminated in accordance with procedures specified in Appendix W. All sources listed by the commenter were beyond the SIA plus 50 km area. Therefore it is not required by regulation that those sources be included in the air quality impact analysis. Regarding the non-specific sources referenced by the commenter as "ethanol and at least one biodiesel plant", all facilities with applications that were deemed complete by Kentucky or Indiana prior to submission of the Cash Creek application were considered in accordance with the procedures required in Appendix W.

b. Meteorological data

The PSD Application assesses compliance with the NAAQS and PSD increments for CO and PMIO using five years of meteorological data from airports in Evansville (surface data). The airport data is not of acceptable quality for air dispersion modeling. The Cash Creek PSD Application, which relies on these data for air modeling, is therefore flawed and likely underestimates modeled concentrations due to the way calms are treated, as discussed below.

Airport data are not collected with the thought of air dispersion modeling in mind. For example, airport conditions are typically reported once per hour, based on a single observation (usually) taken in the last ten minutes of each hour. The USEP A recommends that sampling rates of 60 to 360 per hour, at a minimum, be used to calculate hourly-averaged meteorological data.[46] Air dispersion modeling requires hourly-averaged data, which represents the entire hour being modeled, and not only a snapshot taken in one moment during the hour.

In addition, data collected at the Evansville airport is not subject to the system accuracies required for meteorological data collected for air dispersion modeling. U.S. EP A recommends that meteorological monitoring for dispersion modeling use equipment that are sensitive enough to measure all conditions necessary for verifying compliance with the NAAQS and PSD increments. For example, low wind speeds (down to 1.0 meter per second) are usually associated with peak air quality impacts - this is because modeled impacts are *inversely* proportional to wind speed. Following USEPA guidance, wind speed measuring devices (anemometers) should have a starting threshold of 0.5 meter per second or less.[47] Additionally, the wind speed measurements should be accurate to within plus or minus 0.2 meter per second, with a measurement resolution of 0.1 meter per second.[48]

The airport data used by ERORA, rather than being measured in 0.1 meter per second increments, is based on wind speed observations that are reported in whole knots. Thus, any winds lower than one or two knots are reported as calms, and are thus excluded from the modeling analyses. In no uncertain terms, the conditions most crucial for verifying compliance with the NAAQS and PSD increments (low wind speeds) are being excluded from the Cash Creek analysis because of the choice to use the airport data.

Sensitive and accurate measurements of wind speeds are necessary for measuring winds down to 0.5 meter per second (about one knot), which can then be used as 1.0 meter per second in the air dispersion modeling analyses. There would be no need to label such low wind speed hours as calm, which will greatly increase the number of hours included in the modeling analyses. Again, it is these low wind speed hours which must be included in the modeling data set to verify compliance with the NAAQS or PSD increments.

KDAQ should have required ERORA to collect pre-construction meteorological data for use in the Cash Creek air quality modeling. Cash Creek, which is a major emission source of many air pollutants, should not be assessed for PSD increment compliance using meteorological data collected with none of the quality assurances necessary for air modeling data.[49]

Division's response:

National Weather Service (NWS) data has long been considered adequate for PSD air quality analyses. The Division made the determination that the onsite meteorological data was not necessary based on U.S. EPA's extensive use of NWS data and approval of its use over the past several decades.

Furthermore, it is unlikely that the predicted impacts would be significantly different/higher even if the source had been required to erect a meteorological data collection tower and collect one year's worth of such data. The modeling is based on worst case impacts predicted by AERMOD using five different years of NWS data. In other words, the year of the met data that generates the highest impact is what is used to evaluate NAAQS compliance and Increment consumption.

IV. THE IGCC FACILITY AND COAL MINE SHOULD BE PERMITTED AS A SINGLE FACILITY

The SOB states that "the primary coal supply is expected be provided by the Patriot Coal Company, which operates an existing underground and surface mining and processing operation adjacent to the Cash Creek location. The coal will be delivered by a conveyor from the mine to an onsite receiving transfer-house." SOB at p.l. KDAQ issued the Patriot coal processing facility a construction and operating permit, Permit S-06-333,

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[46] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 4-2.

[47] Id., p. 5-2.

[48] Id., p. 5-1.

[49] USEPA, Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-07, May 1987, p. 55.

on December 6, 2006. Due to the interdependence of the two facilities and the increased production at Patriot necessitated by Cash Creek[50], the facilities must be evaluated as one entire source for the purposes of the PSD permit for Cash Creek. This means that in evaluating whether the Cash Creek source's impacts will be over the regulatory ambient significance levels, both facilities must be modeled together. Further, in determining the Cash Creek source's impact area for each pollutant and the impacts on visibility and other air quality related values of Class I areas, the two facilities must be modeled simultaneously to predict the overall impacts from the Cash Creek source.

Any attempt to model only impacts from the Cash Creek nominal 770 MW facility must be considered circumvention of the PSD permitting regulations and must not be allowed by KDAQ.

Division's response:

The federal (40 CFR 52.21) and Kentucky (401 KAR 51:001) PSD regulations define "stationary source" as "any building, structure, facility, or installation" which emits or may emit a regulated NSR pollutant. Additionally, the rules further define "building, structure, facility, or installation" as "all of the pollutant-emitting activities that belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control)." Therefore under the PSD program, three criteria must be considered to determine whether "pollutant-emitting activities" are part of the same stationary source:

1. *whether the activities are located on contiguous or adjacent properties;*
2. *whether the activities are under common control; and,*
3. *whether the activities belong to the same industrial grouping.*

The Patriot mine and the Cash Creek Generating Station do not belong to the same industrial grouping, nor is the Division aware of any common control between the two companies. Therefore they should not be modeled as one source for PSD.

V. PUBLIC PARTICIPATION

On Wednesday, June 6, 2007, both Meleah Geertsma and John Blair sent requests to John Lyons for an extension of the written comment period. In her request, Ms. Geertsma noted the challenges to finding a technical expert on IGCC within the standard time period, based on the relative newness of the technology. Both requests were denied outright, with the caveat that written comments could be submitted through a representative at the public hearing to be held ten days after the close of the written comment period due to a scheduling problem within KDAQ. Ms. Geertsma again requested an extension on June 19, quoting from Hearing Officer Dickinson's report in the Trimble case, issued earlier that week, noting systemic problems with the Division's treatment of public participation requirements. This report echoed the critiques stated by Hearing Officer Janet Raider in her April report on the Spurlock permit. Mr. Lyons again rejected the request. In neither of Mr. Lyons' response did he provide any justification for denying the requests beyond the extra days afforded by the Division's scheduling problems. In fact, Mr. Lyons implied that he did not have the authority to extend the comment period under Kentucky regulations ("401 KAR 52:100, Sections 2(2)(a) & 2(2)(b), are very prescriptive in that the comment period "shall" begin on the date the notice is published and "shall" end thirty (30) days after the publication date.")

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[50] According to an IEP A press release for the analogous ERORA Taylorville facility, the plant will consume approximately 1.8 million tons of Illinois coal per year. Patriot's three Western Kentucky mines together produced only 4 million tons of coal in 2004. See Peabody Energy Press Release, Nov. 9, 2005, "Patriot Coal Company Earns Reclamation Honors From the Kentucky Department of Natural Resources & Kentucky Coal Association," available at http://phx.corporate- ir.net/phoenix.zhtml?c= 1 29849&p=iro l-newsArticle&ID=78097 4&highlight=. Thus, the Cash Creek facility will require the Patriot mine to potentially more than double its production level, which will in turn significantly impact air emissions.

The blank rejection of these justified requests is unacceptable and evidences the Division's inexplicable and on-going resistance to the public's input on its permits. The public comment period exists so that the public can express its concerns with a permit to the agency, outside of the adversarial, expensive process of an administrative hearing. It is the opportunity for an exchange, with the end goal of meeting the air quality laws and regulations to the greatest extent possible. Blanket refusals to extend the comment period, particularly in light of the numerous and repeated shortcomings in the process itself noted by Hearing Officers Dickinson and Raider which produce delay and confusion for the public, prevent the public from having a meaningful opportunity to comment as the law requires. Nor does Kentucky law prescribe a maximum 30-day comment period as suggested by Mr. Lyons. The above quote conveniently leaves out the language in 401 KAR 52:100, Section 2(1)(a) clearly stating that the Cabinet shall afford a *"minimum* of thirty (30) days for public comment."

Commenters note that, due to the short time period for reviewing this voluminous and complex permit record, we have focused our comments on the BACT limits and not included complete comments on several areas which we believe to be deficient. These areas include the enforceability of numerous permit conditions, as well as the applicant's air quality modeling demonstration and soils and vegetation assessment. It should also be noted that the volume of these comments is in large part due to the extensive work of other advocates to generate the general arguments on carbon dioxide in other cases. The allotted time was wholly insufficient to do the permit-specific review necessary to meaningfully comment on the materials available for public review. Nor was the by-chance additional time to submit written comments at the hearing sufficient. We are aware of others who needed additional time to submit written comments and who had to scramble to find persons to hand deliver the comments and represent these comments at the hearing.

In sum, we are commenting on the insufficient opportunity afforded by the Division with regards to the draft permit. To correct these errors, the Division should seriously consider reopening the comment period. In addition, in the event that comments from this period result in significant changes to the permit limits, the Division should notice an additional comment period on the revised draft permit prior to finalizing it. We finally strongly urge the Division to follow, at a minimum, the recommendations laid out in the referenced Hearing Officer's reports. Ample room exists *now* under the Division's regulations for improving the opportunity for public participation in the ways noted. The Division's regulations also could be improved by amendments clearly laying out the standards for extensions. Finally, we note appreciation for the provision of electronic files during this comment period and recommend that such files be assembled prior to the notice date to enable the timely review of the voluminous files.

Division's response:

The Kentucky Division of Air Quality is bound by the regulation which states "The comment period: (a) Shall begin on the date the public notice is published in the newspaper; and (b) Shall end thirty (30) days after the publication date."401 KAR 52:100, Section 2(2).

The commenter appears to be confusing the requirements for a public hearing with the public notice. " A request for a hearing shall not require an extension of the comment period; however, the Cabinet may allow additional time after the close of a public hearing for public hearing participants to submit their comments in writing. If a public hearing is held, the Cabinet shall: Provide public notice, at least thirty (30) days prior to the scheduled hearing date;"

The plain and unambiguous language of the regulation is that the public comment period expires 30 days after publication of the public notice, and that if a hearing is requested that notice be given 30 days in advance of that hearing. Because of scheduling issues, the public hearing may occur a reasonable time after the public comment period, and comments may be submitted at the hearing.

VI. CONCLUSION

For the reasons stated above, KDAQ should deny the Cash Creek-ERORA draft permit as a matter of law and fully comply with the duty to provide a meaningful opportunity for public participation during the remainder of the permit's consideration.

Division's response:

The Division does not concur; it has fully complied with its promulgated regulations concerning meaningful public participation.

ATTACHMENT I

Responses to Comments

Comments on the Draft Title V Air Quality Permit submitted Steve Jenkins, Vice President of CH2M Hill.

1. Page 2 of 51: this lists a maximum rated heat input capacity for the combustion turbines of 2917 MMBtu/hr. Please note that this is the value for the heat input to each of the gasifers, per the information presented in Cash Creek's application and consistent with GE Energy's coal gasifier design. The heat input to each of the combustion turbines should be 2114 MMBtu/hr, per information presented in the application, which is consistent with the design of the GE 7FB combustion turbine. Note that the 2917 MMBtu/hr value is also noted in the Statement of Basis, under the section "Operating Caps Description".

Division's Response:

> *Comment acknowledged, changes have been made to the permit and the Permit Application Summary Form. The value did not appear in the Statement of Basis.*

2. While the Statement of Basis lists a VOC emission limit, it is not included in the draft permit under Section 2, Emission Limitations. I note that you refer to the emission limits as "BACT emission limits",and that a BACT analysis was not required for VOC. But does this mean that the unit will not have an "official" VOC limit, even though Cash Creek proposed a value?

Division's Response:

> *Since emissions of VOC were not above the PSD significance level, no BACT limit was required. Further, there are no other applicable regulations requiring a VOC limit. Therefore, the Division has no regulatory authority to impose a VOC limit. The permit requires post-construction testing to confirm that BACT was not required for the VOC emissions.*

3. The Statement of Basis is informative in that it presents the emission limits on a gasifier input basis and the combustion turbine input basis. In the original Cash Creek application, they had presented the heat input for the combustion turbines, but not the coal input to the gasifiers. At the time, several of us in the IGCC industry had noted to ERORA and their consultant that the emission limits for an IGCC unit using coal should be compared to a pulverized coal unit, not to a gas-fired combined cycle unit that uses natural gas as a fuel. In the amended application, Cash Creek modified this and provided their information based on the gasifier heat input value (2917 MMBtu/hr per gasifier, for a total of 5,834 MMBtu/hr), and proposed their emission rates on the gasifier heat input basis. In the revisions to Subpart Da, EPA correctly placed IGCC units into the NSPS for Electric Utility Steam Generating Units, the same category with pulverized coal boilers, and removing IGCC from Subparts GG and KKKK, which are for gas-fired combustion turbines, not boilers. The IGCC industry is now working to standardize its approach in air permit applications. At the Gasification Technologies Council regulatory workshops, we point out the comparison of coal-based IGCC to pulverized coal-fired boilers and how to calculate and propose emission limits on the gasifier heat input basis, in order to compare coal to coal, not coal to natural gas.

We note that on page 4 of 51 of the draft permit, under Section 2 (j), it states that the BACT emission limits are based upon heat input to the combustion turbines. This would not be consistent with what the IGCC industry is working toward, and will likely cause some confusion to those who read the permit to see what the emission limits are, assuming that the emission limits would be on the basis of coal input to the gasifiers as with other IGCC permits. Should you choose to keep the emission limits on the basis of heat input to the combustion turbines, we would suggest that you move the statement in Section 2(j) up to the beginning of Section 2. Also, since people will download the permit and may not download the Statement of Basis, a table that presents the emission limits on both the gasifier heat input basis and the combustion turbine heat input basis would be very informative (as it is in your Statement to Basis document).

Division's Response:
The Division acknowledges the comment but does not agree with the suggested changes.

ATTACHMENT J

Comments on the Draft Title V Air Quality Permit submitted by at the public hearing.

KENTUCKY ENVIRONMENTAL AND
PUBLIC PROTECTION CABINET
DIVISION FOR AIR QUALITY

PUBLIC HEARING
June 29, 2007

HELD AT THE HENDERSON COUNTY COURTHOUSE
FISCAL COURTROOM, THIRD FLOOR
ON FRIDAY, JUNE 29TH, 2007, AT 6:30 P.M.

APPEARANCES:

Jim Morse
Supervisor, Permit Support

Donald Newell
Manager, Permit Review

Ben Markin
Supervisor, Combustion Section

JIM MORSE: Good Evening. My name is Jim Morse. I supervise the permit support section at the Division for Air Quality. I'll serve as your moderator tonight.

This public hearing is now in session. If you have not signed the attendance sheet at the registration table up here, that has been marked as the attendance sheet, if you would do that, even if you don't intend to comment. We need a full list of who attended this hearing.

Our division is responsible for regulating air pollution in Kentucky. We operate a central office in Frankfort and eight regional offices, including one located in Owensboro, which serves the Henderson County area.

The purpose of tonight's public hearing is to receive your comments on the draft permit for construction and operation of a coal-fired electric generating plant.

Copies of the draft permit and supporting information that were used to write the permit were made available at the local courthouse right here on May 20th, 2007, and advertised in the Henderson Gleaner on the same day. This hearing was also advertised at that time.

Our court reporter is Cathy Passmore. You can obtain a copy of the transcript of this public hearing by making arrangements directly with her. She'll advise you of the expected time frame for completion of the transcript and the cost for a copy.

In a few minutes I'll describe the procedures we'll be following tonight to take your comments.

First, Mr. Don Newell, our staff engineer will give you some details of the review our division has conducted of the proposed project.

MR. NEWELL: Thank you, Jim.

Again, my name is Don Newell, N-e-w-e-l-l. I'm also with the Division for Air Qualify in Frankfort.

UNIDENTIFIED PERSON: Hey, turn it up a little bit.

MR. NEWELL: Will you turn it up, Jim.

MR. MORSE: There is no provision for turning it up. Just speak into the microphone.

MR. NEWELL: I guess I'll have to turn

it up.

This public hearing is to receive comments on the draft permit for the electric generating station known as Cash Creek. It's a PSD, that's prevention of significant deterioration, title V after the title in the Clean Air Act which requires permitting of this type of source permit.

According to the Clean Air Act, stationary sources that have the potential to emit over 100 tons per year of any of the criteria air pollutants are required to have a federally enforceable title V air permit. The benefits of the title V permitting process are that it requires industry to focus on air quality implications associated with their operations. We urge the permittee to design or redesign equipment and their operations to comply with the regulations. It allows for clarification of requirements because it increases the likelihood of a compliance for the source and by the source and it increases the understanding of the permitting process. This increases the opportunity for introduction of additional pollution prevention and controls. All of this is required by the steps that are taken in compliance with the Clean Air Act.

It also makes sure that by addressing these questions up front, in other words, before construction, the facility will be built right the first time and it will not have to undergo retrofit and redesign at a cost of time and money to comply with the law after the fact.

For this particular source there were several types of review that had to be done. As I mentioned, this is a prevention of significant deterioration or PSD permit, so it had to ensure that all of the emissions from this plant would be within the limits of the national ambient air quality standards. In PSD review you determine a baseline of air pollution, air emissions that are currently existing and then you evaluate whether that baseline, plus the emissions from the new facility are in compliance with those national ambient air quality standards. All that analysis is done before the draft permit is issued.

It also requires an analysis to determine what the best available control technology is for the major pollutants and ensure that the company or requires the company to include that best available control technology in the design of the plant.

This particular one, this particular facility, because it's within the national park

services area of interest, with respect to Mammoth Cave National Park, also had to undergo class I, Mammoth Cave National Park is a class I area, so this facility had to undergo class I area impact analysis to ensure that it did not cause unacceptable degradation to the Mammoth Cave National Park.

In determining what BAT, or best available control technology is, all potential technologies have to be identified. Technically infeasible options can be eliminated, economically infeasible options can also be eliminated, the remaining technologies are ranked by control effectiveness, taking economic, environmental and energy impacts into account, the best technology must be selected for control. This facility also underwent that analysis.

The division received an application

for the Cash Creek generating station, worked with the company to make sure that the application was complete and accurately described the facility, and then our staff engineers worked to develop this draft permit which has been presented for your review so that you can make any inputs to your beliefs about the impact of this facility.

This draft permit is not a construction permit. This draft permit does not carry construction authority, that authority will or will not be granted then. Determination will not be made until your comments have been received and evaluated. A copy of this draft has also been sent to the U.S. EPA, they've had their opportunity to review it. It's been sent to the federal land manager of Mammoth Cave National Park and it's also been sent to those adjacent states, in this case Indiana and Illinois so that interested citizens in those territories could also have the opportunity to comment.

The public comment period has run for 30 days. Your concerns will be evaluated and the division will respond in writing to each of those concerns. Taking into account the comments that we received, we will then, if there are no regulatory or statutory prohibitions to the contrary, issue a proposed permit for Cash Creek. But, again, let me emphasize, that will not happen until we have fully considered all of your comments.

So we like to thank you for being here. We would like to say that we appreciate your participation in this process. And we look forward

to working with you to make sure that this endeavor has a satisfactory conclusion. Thank you.

MR. MORSE: Thank you, Don.

Now, let me describe the way we will conduct the rest of the meeting. I hope that each of you will recognize that there may be differing opinions in the room about this proposed project. Please let me remind you that every person here is entitled to voice his or her opinion. I will ensure that each person is allowed a fair and uninterrupted opportunity to make comments.

Persons providing comments tonight will not be questioned by anyone regarding their comments except that I may ask a clarifying question if I feel that a comment is not clear.

Our division will not determine its position tonight regarding any suggestions you make. It's important that our staff thoroughly review all the additional information that we receive during the public comment period, pro and con, prior to finalizing a position on each specific issue. Our agency has the authority to address only the air quality aspects of this project. Therefore, we would appreciate it if you would limit your comments tonight to the air

quality aspects of this proposal.

If you have other comments or concerns not having to do with air quality, I'd be happy to assist you in determining the appropriate agency or office towards which to direct them.

It's not necessary for anyone to read their entire written comments tonight. Verbal and written comments will receive equal review and consideration. If an individual has a long statement, I would urge you to summarize it in tonight's presentation and provide us a full written copy. Given the number of people who indicated their desire to speak, I would ask that verbal comments be limited to five minutes, if possible. I will indicate to you when you have one minute left and when the time limit is up. If you cooperate with us on this request, everybody that wants to speak tonight will have a reasonable opportunity to do so and we'll all still be able to go home at a reasonable hour.

Before you begin your comments, I'll ask you to come up to the podium, state your name, who you represent, and speak directly to our court reporter. If you have written comments, please leave a copy of those with the court reporter.

Now, everybody didn't print their name like it says in big print up there so bear with me if I'm unclear on who you are. L. Smithyman.

MS. SMITHYMAN: Thank you for having us here tonight. I'm Linda Smithyman, city of Henderson. I'm a member of the Sierra Club. I would like to read from a flyer that the Sierra Club has produced about liquid coal.

"Liquid coal releases almost double the global warming emissions per gallon as regular gasoline. The powers behind liquid coal want the government to funnel billions in subsidies and tax breaks to artificially create an entirely new industry. At a time when we need to be reducing our carbon emissions, liquid coal represents perhaps the dirtiest, most expensive, and most dangerous energy gamble we could take.

Manufactured by converting coal into a gas and then into a synfuel, liquid coal requires huge inputs of both coal and energy. In fact, one ton of coal produces only two barrels of fuel.

More than four gallons of water are needed for every gallon of transportation fuel produced, threatening our limited water supply. If we were to replace only ten percent of our nation's

transportation fuels with liquid coal, we would have to increase coal mining by over 40 percent.

An increase of coal mining on a scale this large would also jeopardize the long-term prospects for coal, including its use as a source of about half our electricity. Doubling or tripling our use of coal can quickly deplete our reserves.

Liquid coal is simply not a smart answer for our energy future."

What price do you put on the future health of yourself, your family, and your neighbors? Thank you.

MR. MORSE: Thank you, Ms. Smithyman. Ms. Christine Belt, please.

MS. BELT: Hello. I'm Christine Belt and I am a concerned citizen. I want to thank you for allowing me to voice my opinion this evening and I want to voice opposition to the Cash Creek power plant.

I would also like to state my support of the written comments submitted by Valley Watch and Sierra Club. I understand the Henderson areas need for new jobs, but I ask everyone involved and affected by this decision, why do we have to pay

for economic development with our health? Why do we have to put our health and our childrens' health at risk for jobs?

Our region already has a high number of coal burning power plants, 17. The biggest grouping in any region in the country or anywhere, I think. We cannot afford another. There is no such thing as clean coal, as the Cash Creek facility propose. It will create high levels of pollution in an area that is already heavily polluted.

On page 27 of Cash Creek's permit statement of basis it reads the division has not required the application to include an air quality impact analysis for ozone. I ask, why not? In the next paragraph the permit reads the purpose of these analyze is to demonstrate that allowable emissions from the proposed project will not cause or contribute to air pollution in violation of a national ambient air quality standard in an air quality control region. Hello. If this proposed plant is created, anytime the wind blows a certain direction Vanderburgh and Warrick County, two areas already at non-attainment for particulate matter and ozone issues, will be greatly affected. That

doesn't even mention what will happen to the Henderson area. We cannot afford the estimated 700 tons annually of nitrogen oxides that will be released into the air as proposed in this permit.

On page 33 of the statement of basis it discusses the affect on soil and vegetation. The predicted ambient concentrations due to the project are below the NAAQS and PSD increments and no significant off-site impacts are expected from the proposed action, therefore, the potential for accurate impact to either soils or vegetation is minimal. It is concluded that no adverse impacts will occur to sensitive vegetation, crops or soil systems as a result of operation of proposed project. I ask, how can 391 tons per year of sulfur dioxide released into the air not have an adverse impact? Sulfate dioxide is the main component of acid rain, which has a very adverse affect on vegetation and crops.

These are only two examples of the adversed effects Cash Creek will have. I'm concerned that major adversed effects are being ignored in an effort to push this project for economic development.

Unfortunately, all the costs are

estimated and the general public isn't aware of the financial costs involved. It is estimated that capital cost for IGCC plants, which are integrated gasification combined cycle plants, are estimated to be 20 to 40 percent, 47 percent higher than traditional coal plants. The Department of Energy reports that IGCC plants are seen as too risky for private investors. It requires large subsidies from the federal, state and local governments. So not only are we paying a health cost, but down the line we'll be paying a tax price as well.

I believe that the economic risks and the health risks associated with this plant outweigh any perceived gain of economic development. As a region, we must -- why must we continually be asked to pay for economic development with our health? Thank you.

MR. MORSE: Folks, as a courtesy to others, if I could ask you, if you've got your cell phone with you just put it on vibrate, please. Thanks. John Thompson.

MR. THOMPSON: Good evening. Can you hear me? Yes?

THE AUDIENCE: Yes.

MR. THOMPSON: Okay. Well, I will try

to speak loudly just in case.

My name is John Thompson. I direct the coal transition project of the Clean Air Task Force. Clear Air Task Force is a national nonprofit environmental organization. We are headquartered in Boston. My address is 231 West Main Street, Cardondale, Illinois 62901.

Clean Air Task Force focuses on two key air pollution issues facing this century; one is global warming, the other particulate matter.

I have a bachelor of science in chemical engineering from the University of Illinois. A master's in business administration from Washington University in St. Louis. I testify regularly for environmental groups and others on coal matters. I review air permit applications for the Clean Air Task Force. I served as the co-chair of the Western Governors Association. Committee on advanced coal reviewing both pulverized coal and IGCC technology and I'm here to offer comments in two areas. First, I would like to make two very specific and limited comments on the air permit and I would like to make three more general comments about this facility in general.

First, I reviewed the permit limits and

I consider these to be appropriate limits for best available control technology. This plant will be one of the cleanest coal plants in the country.

Second, I would like to just note that the statement of basis that Kentucky has issued for this plant is an exceptional document and I think that it is a model for future regulators in other states who are considering both conventional and IGCC plants.

What I have done, I'd like to make three comments that are more general to those of you in the audience and I prepared several diagrams which I have asked the hearing officer to previously mark. These are Clean Air Task Force Exhibit Number 1, Clean Air Task Force Exhibit Number 2, and Clean Air Task Force Exhibit Number 3. And I'd like to make, as I said, three general comments.

The first one is about how -- first of all let me just -- if you don't mind.

MR. MORSE: Sir, if you'll face the court reporter. We're not addressing the crowd here. We're taking statements.

MR. THOMPSON: Okay. I'll still glance over at you-all in the audience every once in a

while here.

The first issue I'd like to address is how extremely low the air emissions are from this particular facility and for that, as I had indicated earlier it is, if built, would be one of the cleanest coal facilities in -- not only in this country but in the world.

Exhibit Number 1, which I'm holding in my hand, consists of a table that shows Cash Creek's proposed emissions versus a nearby coal plant, relatively nearby, called the Gallagher Station. And they are roughly the same size facilities. Gallagher in 2005 emitted some 61,000 tons of sulfur dioxide and nitrogen oxide. Cash Creek, in contrast, if it were to operate 24 hours a day, seven days a week, would emit no more than a thousand tons of NOx and SO2 together. In fact, if you look at it, Gallagher emits more air pollution from sulfur dioxide and nitrogen oxide in three days than Cash Creek will in an entire year. That is a radically lower level of pollution.

I'd like to address a second point. And that's the impact of adding another coal plant in an area such as this that already has high levels of air pollution. The sulfur dioxide, the nitrogen oxide that are emitted by power plants in the Ohio Valley are key contributors to non-attainment designations in nearby counties for ozone and particulate matter. And I know that it sounds counterintuitive to say this, but actually if you build this plant the air quality in this region, in my opinion, gets better, not worse. Let me explain why that point may seem counterintuitive to you. After all, this is an additional plant. It's adding pollution into the air. So how is it that a plant that can -- is a new plant, that's adding more pollution, could possible reduce pollution in the surrounding air? And that has to do with how coal plants are dispatched. By dispatched, I'm referring to perhaps an analogous situation is when you call a taxi. The dispatcher decides when to send the taxi to the location that you've sent, you've requested. So it is when coal plants dispatch. They dispatch in a certain order. In coal plants such as this, are always built primarily to meet new demand for energy and electricity. The small portion, at least a small portion of it, displaces existing coal plants. And when you look at a plant, the many, many plants that are in this area, what you'll find is that an

IGCC plant, because it is highly efficient, will be dispatched ahead of the exiting coal plants. If this plant idles Gallagher for as little as 80 hours over the course of the year, there's enough air pollution offset from that coal plant to actually offset all the emissions from Cash Creek.

Gallagher and plants like that generally operate some 4,700 hours a year or more and so to -- the idea that it is highly likely, in my opinion, that this plant is going to idle existing coal plants far more often than even 80 hours. So the end result of that, is that in the region NOx and S02 are likely to go down because this is a radically cleaner plant, because this plant is more efficient and because it's going to dispatch ahead of all the existing coal plants in the region because of its efficiency.

I'd like to address a third point, and for that I'm going to now move to Thompson or to Exhibit Number 2. And that is the issue of global warming. Global warming is real. Carbon dioxide emissions from coal plants account for something like 40 percent of the C02 that is released into the atmosphere. If we don't make radical reductions in the amount of C02 that is admitted

into the atmosphere by mid century, we will see, in my opinion, large scale global warming that may threaten extinction of many species. IGCC plants, such as the Cash Creek facility, are ideally suited for capturing and sequestering this carbon dioxide before it's admitted into the atmosphere. Exhibit Number 2 --

MR. MORSE: Mr. Thompson.

MR. THOMPSON: I know, I'm hurry up here, sir. Shows a map that I prepared for testimony last week on the Edwardsport IGCC plant. It depicts the three state region. This yellow region of the saline aquifers that are good targets for this region for the sequestering part. The areas in red are the oil and gas fields where the C02 from a plant like this would make excellent enhanced oil recovery opportunities. What I'd like to suggest to you is that if we're ever going to get global warming under control, we're going to have to make at least 80 or more percent reduction of C02, worldwide reductions, including from all the power plants, all the industrial sectors in this three state region. This technology has the capability of advancing that option. Why? For this I'm moving to Exhibit Number 3. My final

exhibit.

There are three levels that an IGCC plant can capture carbon at. Roughly 20 percent, roughly 50 percent, roughly 90 percent. This plant will not, to be clear, capture carbon from its outset, but it has very inexpensively the option to do 20 percent very soon. That is enough to advance sequestration in this region and enhance oil recovery so that can make deep, deep reductions in C02. And I would just suggest to you that unless we multiply those options for capturing carbon, we will never get progress on this topic.

In conclusion, I'd just like to say that I understand in this community you have a lot of natural beauty. You have a heritage that includes John James Audubon and his contribution to ornithology. If we don't solve global warming, the efforts that John James Audubon made, John Muir made, that Teddy Roosevelt made, that Rachel Carson has made, indeed, all of the efforts that we, as a conservation environmental community, have made to protect this planet over the last hundred or more years will be out the window. It's just to you.

If we work together to advance enhanced oil recovery at this particular site, then we

actually might make a difference so that our children and their children will have a climate that is one like John James Audubon and John Muir had experienced in their lifetimes. Otherwise we face massive extinction of species, rapid disintegration of ice sheets, rises in sea level. Paradoxically this plant is contributing to the solution of air pollution problems and I hope that the division will issue an air permit as rapidly as possible. Thank you.

MR. MORSE: Let me re-emphasis a couple of things that I said earlier tonight. We're taking your comments, I would like you to address them to the court reporter. These comments and the responses to the comments and the proposed permit that results from this input will be made available again at all the same places, including this courthouse that it was made earlier with the draft permit. Every comment that's made we will get a chance to review. Anybody else that hasn't been here tonight will get a chance to see these comments and what our responses were to them.

I would also ask that you refrain from ridiculing anyone, and respect each one as we conduct this hearing. Michele Morek.

MS. MOREK: Thank you for the opportunity to speak. My name is Sister Michele Morek. I am the president of Ursuline Sisters of Mount Saint Joseph, a group of religious women who serve all over the United States and in South America. Our national central headquarters are located just south of Curdsville, Kentucky. I would like to speak on behalf of a large population of people living and working immediately downwind from this proposed plant that is, in addition to the population of Curdsville and Delaware, Kentucky.

Among other things, the sisters' motherhouse serves as the retirement home for 80 elderly and infirm women religious, several of whom have respiratory impairments. In addition, we have about 20 sisters who live and work on campus, plus about 85 employees who work in the retirement home and in the offices of the central administration. I believe we are the largest employer in Western Daviess County. So that is almost 200 people who live or work there.

That number does not include the employees and clients of the Mount Saint Joseph Conference and Retreat Center, also located on this site. The conference and retreat center serves about 5,000 people a year-business, educational, and religious groups who come for a day or a week to use the facilities. All together, with all the events we have on campus, we probably have over 20,000 people visiting our campus every year.

I was raised right across the river from a large coal burning power plant and I have seen over the course of my lifetime the environmental degradation, loss of air quality, and cost in human health that a coal-fired plant brings to the area. We just ask that you consider the human cost and quality of living issues before citing this plant. Would you build this plant five miles upwind from your grandmother's home? We have 80 grandmothers living in our home. Thank you for your attention to our input.

MR. MORSE: Thank you. Zachariah Matthew Hust.

MR. HUST: How you-all doing tonight? I believe this plant here being proposed in Henderson County would be a real good thing. It would bring a lot of jobs for hard working people here in this community, going to have an impact on a lot of peoples' lives. I believe it will be a

good thing. Got a lot of long-term jobs for people and short-term jobs, you know, for a lot of us construction workers. Be a real good thing. I think you-all ought to think real hard about it. You-all have a good evening.

MR. MORSE: Thank you. James P. Marquart. James P. Marquart?

UNIDENTIFIED PERSON: He's hard of hearing. He's back there. Dad.

MR. MARQUART: I took my hearing aid out because the battery died. I look out and see all my friends here. I wish I could say --

MR. MORSE: Sir.

MR. Marquart: Some of my friends are

for it and some of them are against it and --

MR. MORSE: Sir.

MR. MARQUART: And work with my friends so I can't say --

MR. MORSE: Mr. Marquart --

MR. MARQUART: My name is James P. Marquart. I'm a retired CPA from Clarksville, Indiana. I was educated in Kentucky. I was raised in Kentucky. I know what it's like to make $2.00 a day sunrise to sunset working on a farm. I went to Sedic (phonetic) High School, Boldman (phonetic)

College, graduated and then went to Washington. And now I've come back in '95 to become a gentleman farmer. I wasn't smart enough to be a farmer. So then I went to Indiana, I went to Hoosier in '95 and now I'm coming back to Kentucky to tell you that I understand, if I lived here I would want to support it too, Cash Creek, it's cash for a few years, cool water down by the creek, it's a job, but then what happens afterwards. Are we going to live long enough to breath the air? Now it's not going to hurt me, I'm 73 years old. I'll be upstairs, but your children and grandchildren they're going to have to pay the price for it.

There are better answers I think. I don't have the benefit of specific knowledge of having reviewed the paperwork supporting this thing so I can't speaks to the rules primarily --

MR. MORSE: Mr. Marquart.

MR. MARQUART: I want you-all to really, really think before you make this decision.

MR. MORSE: If you'll please confine your addressing to the court reporter. Thank you.

MR. MARQUART: That's about all I have to say young lady this evening.

MR. MORSE: Jack Grappo.

MR. GRAPPO: Good evening. My name is Jack Grappo. I work for the University of Kentucky Center for Applied Energy Research Laboratory. I have a BS, MS and PhD degrees in engineering. In the course of my work I've had the opportunity to work with gas location plants throughout the United States and around the world. And I came here from Lexington tonight just to make a few comments on IGCC and gasification technologies in general.

Gasification, for those of you that are not familiar with the technology, is arguably the most thermally efficient and the lowest emissions, excuse me, lowest emission means of utilizing our coal resources. If we have a need to increase electricity production in the United States and in Kentucky, which we certainly do, if we have a need to continue to use coal as a primary fuel for these electricity productions, which we certainly must, and gasification and combined cycle strategies are certainly the most technical sound choices and the environmental responsible choice we can possibly make. Thank you.

MR. MORSE: Jim Gregory.

MR. GREGORY: Thank you. My name is Jim Gregory. I'm born and raised right here in

Henderson County. I work at one of the current coal-fire plants, the Robert Green Plant in Sebree. I know that we have a lot of opposition to those who are concerned with the environment. I just want everyone to realize that three-quarters of the employment at the powerhouses have to do with pollution control. It takes very little to make electricity. It takes a whole lot of effort to clean the air up and that is, whenever you see this huge sprawling plant out there, remember three-quarters of it is to clean the air up and the things that are done to keep our families safe. I've heard several comments this evening that said do you want your grandmothers or your children to live close to a power plant. It wouldn't bother me at all. I rather have them live close to a power plant than I would to the smells of the chicken house or the solid waste facilities that's out there. I appreciate the opportunity to make comments, and I hope you grant this permit. Thank you.

MR. MORSE: Mike Hall.

MR. HALL: My name is Mike Hall. I'm also a current -- I'm also a resident of Henderson. I was born and raised here.

I just have a couple quick comments. I would like for us to think about tonight, like I said, we are expressing the concern about the air quality, and being a resident of Henderson, that is an issue with myself and our family. I would like to -- we're hearing some of the implications of the -- some of the new technology that's available today. I would like for us to listen to those comments and also remember that if this is something that we -- if we can minimize some of the older units in any way by introduction, introducing a new, more efficient power plant I believe that would be in our best interest. Thank you.

MR. MORSE: Tony Byrne.

MR. BYRNE: I am Tony Byrne. I live in Daviess County about three miles directly downwind from the proposed power plant. I'm concerned how the power plant will affect me, my family, my grandkids and all my neighbors. We also have a family farm that is right across the river from the proposed power plant and I like to hunt, I like to fish, and I just wonder how it's going to affect the wildlife.

I know this has been several years ago but me and a friend were quail hunting down by the

Sebree power plant, except we were on this side of the river and the power plant is on the other side of the river and it had snowed probably three or four days before, and you wouldn't know it was snow when you saw it because it was mostly black. So, if this power plant does come on line, I hope it sure does better than the one at Sebree. That's really all I've got to say.

MR. MORSE: Don Clements.

MR. CLEMENTS: My name is Don Clements. I also live west Daviess County probably three miles downwind from the proposed power plant site. If this power plant was needed locally for the citizen of west Kentucky then who could be against it? We live here. We raise our children here. We need the power plant. This is going to be a merchant plant. Shipped out of state for people in California, the people on the east coast will benefit. They say let the dumb old Kentuckians take in the particulates. We don't want it, but we want their cheap power. If it were needed locally, if the investors lived here among us, raised their children and grandchildren among us then build it.

For the gentleman from Southern Illinois who said that Gallagher may shutdown or implicated that Gallagher will shutdown if this power plant came on line, I think is fooling himself. This power plant production will be shipped out of state. Gallagher will continue to perform as well as Big Rivers, Sebree and every other plant in the area will continue to perform at top capacity to supply the needs of the local people as well as ship the excess power on the grid to other areas of the country who don't want the dirt and the filth in their state, but let the Kentuckians have it, they don't know any better. Thank you.

MR. MORSE: Brad Bredhold.

MR. BREDHOLD: My name is Brad Bredhold. I'm from Evansville, Indiana. My concerns with this plant are with economic development. It's going to create jobs, but how many jobs are we going to lose due to non-attainment levels. Like Evansville, Warrick County, Vanderburgh County have reached a non-attainment level or close to it for particulate levels and everything else and that's going to affect the economic, other facilities for jobs and everything else that's going to come into the

community. So if you build this plant, you're basically throwing all these other jobs out the window because no one will move factories or any other type of job here for people. And that's pretty much all I've got to say.

MR. MORSE: Thank you. Jean Webb.

MS. WEBB: Hello, my name is Jean Webb. I live in Vanderburgh County in Indiana. I'm among the very fortunate people that have health insurance. I'm even more fortunate that my insurance provider provides me with information to help me maintain my health. My provider, Welborn Health Plan, sends to my home a quarterly publication called Health Well. I read this publication because I know I'm responsible for staying healthy. I exercise, I try to maintain a healthy weight, I avoid high fat foods, and I don't smoke.

My latest issue of Health Well contained an article titled, "Air Pollution Can Break Your Heart." This article cites a 15-year study on health effects of air pollution. It concludes that long-term, living in the nation's most polluted areas can slice up to three years off the average life span.

I live in an area of the nation that is officially in non-attainment from PM2.5. That means me. I live in one of the nation's most polluted areas. Despite my efforts to exercise, maintain a healthy weight, avoid high fat foods, and refrain from smoking, I'm losing three years. My children and friends that chose to live in this area are losing three years. I still feel that I need to be responsible for my health, but all I can do to protect myself from this danger, short of moving, is to ask you to please not allow this proposed plant to operate if it will result in a net increase of pollutants.

Three years of life is too high a price for the benefits this facility might provide. Thank you.

MR. MORSE: Carly Watson.

MS. WATSON: Good evening. I'd like to say that I agree with comments made by Valley Watch and Sierra Club and Jean Webb and a lot of the opponents of the Cash Creek power plant.

I'm a resident of Newburgh, Indiana, and I represent a group called Airaware. I am here to urge you today to oppose the Cash Creek power plant that is proposed in this area.

Before I start, I want to say that I've

been sitting on the fence with this issue for quite some time. I've had mixed feelings about this plant for a variety of reasons.

First of all, Cash Creek will use IGCC technology, which we've heard about tonight. It sounds great, compared to what is out there it is a lot better. Compared to Rockport, Gallagher, Gibson power plants in Indiana it is a lot better. However, what are the facts about this technology today? Well, while significantly less in terms of emissions, Cash Creek is not without a cost. It will still produce air pollution, especially in the form of particulate matter. And when we talk about air pollution, we are generally talking about two different types of pollution. We are talking about ozone pollution and particulate matter pollution. Particulate matter is of great concern to me because Warrick County has a non-attainment status with the EPA. Ostensibly I am concerned about anything that will add to the already high particulates in our air.

The gentleman from Carbondale was trying to say that emissions from this plant will offset emissions from existing power plants. Well, there is no suggestion or no suggestion has been made that this power plant is going to replace a grandfather plant that is existing right now. We have no evidence of that. Because if we did, I might think differently about this plant. I would love to see maybe something change in terms of a shutdown of Rockport and then maybe IGCC, but there's nothing suggesting that, nothing at all.

Next, I'd like to talk about particulate matter or PM2.5 because again that is where Warrick County is non-attainment. And I'm not trying to raise anxiety in the room by talking about this but these are the facts. We know that particles in air which is PM2.5 m is 2.5 microns or smaller in diameter. The particles are so small, they get down deep in your lungs and your lungs cannot expel them. Essentially the particles travel around your bloodstream, they can transplant in your vital organs, and can cause heart attacks, strokes, lung cancer, other cancers, and asthma. We have quite an asthma problem over in Vanderburgh County. Overall the poor health of our community has more to do with the 17 coal-fired power plants in 62 miles radius of our town, than it does with fat, sedentary smokers. Do we really want one more

power plant to this number? No. The answer is no. It is still more pollution.

In addition to its unclean reality, IGCC technology is not fully developed yet. The companies are still unsure how to sequester the carbon dioxide. And although field studies are being conducted with regard to the carbon sequestration, no conclusions have been drawn yet.

We don't need more C02. I think when we consider this issue we need to ask ourselves in what direction we want the Tristate area to go in. Do we want to continue down a heavily industrial path where the only type of businesses that want to locate here are utility companies or ones that naturally produce large volumes of pollution?

If we choose the industrial path I think at some point we will see a negative population growth. More pollution means economic disaster in the long run, not economic development. Young people do not want to raise their families in unhealthy environments.

Thank you for your time. I hope you seriously consider the issue as your decision will impact the health of the citizens of Newburgh, Indiana.

MR. MORSE: Thank you. William Bowker.

MR. BOWKER: Thank you for this opportunity, Mr. Chairman. I'm William Bowker, director of the Division of Fossil Fuels and Utility Services in Kentucky Office of Energy Policy.

I wish to express my strong support for Cash Creek Generation Integrated Gasification Combined Cycle coal production facility. Let me explain why we in state government, why we in the alternate energy policy do favor or do support this kind of technology.

Cash Creek Generation represents the advanced technologies that will be necessary if this nation is going to meet its growing energy needs while protecting the environment. It's the type of advanced technology that will enable Kentucky to attain major goals in its comprehensive energy strategy.

In 2004, Governor Fletcher put together a task force on energy policy. It was made up of leaders of the Executive Branch and from the General Assembly, held meetings throughout the state with environmentalist, academia involving energy industry, agriculture and many others and

developed an energy strategy made up of 54 recommendations. My immediate response to those who have to do with that addressed creating markets, new markets for Kentucky coal and for advancing clean coal technologies.

Now, as far as addressing the permit itself, the point made by the gentleman from Clean Air Task Force by, Dr. Grappo, that integrated gasification combined cycle is the cleanest or a very, very clean and I believe it's the cleanest way to use coal. It doesn't burn coal, it gasifies coal and because it gasifies coal it captures and separates the pollutants, the sulfur, the nitrous oxides, the carbon dioxide can be separated before they go into affluence and have a bigger move. It's efficient, it's low cost and it's the cleanest way to reach very, very low levels of emissions.

Why we're interested in this technology, why we support it is because our charge has to do with the economic growth of Kentucky and it has to do with the energy security of the United States. This plant is, as I said, an advanced representative of the most advanced technology for utilizing coal.

Coal is a major force in the economy of Kentucky. The five billion dollar industry employs almost 17,000 miners, over 2,700 in West Kentucky. As the third leading coal producer in the United States, Kentucky produced in 2005 almost 120 million tons of coal. Severance tax revenues alone were $224,000,000 in the fiscal year 2006. As impressive as these figures are, keep in mind how coal production and employment have declined. In 1990, Kentucky produced 173 million tons of coal, 45 million in West Kentucky. Almost double what's being produced right now. West Kentucky's record production was over 56 million tons in 1975. In 2005 this was down to 25 million tons. In 1990 West Kentucky had 5,600 miners. In 1980, West Kentucky mining employment was near 12,000. Today, there are 2,700.

Cash Creek Generation will create a new market for Kentucky coal immediately. About 2 million tons of coal which will employ about 150 miners. This, in addition, of course, to 750 to 1,000 construction workers working in this area for three or four years and a couple hundred, 200 highly skilled plant operators.

As far as United States, according to the Energy Information Administration, economic

growth in the United States will result in an almost 50 percent increase in electricity demand by 2030. And according to the EIA, coal is expected to supply most of this new generation, rising from today's 50 percent to about 58 percent of the national generation. Now, this, of course, would be good news for the coal industry and Kentucky and elsewhere. It's not certain, however, how coal is going to play this role. This expectation on the part of the Energy Information Administration takes into account conservation, it takes into account renewals, and it still comes to the conclusion that in this country we're going to have to continue to rely on coal. And if we're going to do that we have to develop the best technologies for using coal and Cash Creek represents IGCC, integrated gasification combined cycle, which is, again, the most advanced and cleanest way to use that coal.

If we don't use coal in the United States we'll have to turn to other sources, increasingly probably to natural gas. We all know since 2000 how natural gas prices have tripled. How in the past few years it's gone up to $15.00 a thousand cubic feet. If we can't find a way, as IGCC shows us a way, to use coal cleanly and to use

the coal to supply our energy, we're turning increasingly to natural gas and want to import more natural gas and we will then begin to rely on other countries, unstable, unfriendly in many cases for natural gas as we do now for about 55 or 60 percent of our oil, of course.

So in sum, we're very strongly in favor of the Cash Creek project because it advances integrated gasification combined cycle. We think that advances the economic interest of Kentucky and we think that it advances the ultimate energy policy, energy security policy in the United States. Thank you.

MR. MORSE: Thank you. Ryan Zaricki.

MR. ZARICKI: Hello, my name is Ryan

Zaricki. I grew up in Rockport, Indiana. I graduated from Rose-Hulman Institute of Technology in Terre Haute, Indiana, with a bachelor of science in mechanical engineering and I lived out in Colorado for the past five years. But recently I decided to move home and I now reside in downtown Evansville, Indiana. I would like to talk to you about options.

In the Midwest, we do have an abundance of coal reserves. Some say the coal reserves in Illinois alone match or exceed the oil reserves in Saudi Arabia. But with the transition into a new millennium, so too comes the transition to a new way of providing fuel and energy to the people of our region, our country, and our world. In a presentation titled Gasification: The Enabling Technology James Childress states that the growth forecast for the coal gasification industry is only five percent annually, with only 19 percent of its output going towards power production.

On the other hand, "Wind power has been expanding rapidly, averaging about 15 percent annual growth over the last decade, but nearly 30 percent over the last five years." Wind power has steadily declined in cost since 1980, and it is currently price competitive with other forms of power production like coal, if not cheaper. Along the same lines, the solar power industry is experiencing the same type of growth. According to the Solar Energy Industries Association, "Global photovoltaic market growth has averaged a stunning 25 percent plus annual growth over the last ten years, with worldwide growth rates for the last five years well over 35 percent." These numbers prove that while overall energy production from

these sources is still minimal compared to conventional power production, they are growing consistently and becoming a force to be reckoned with. Oh, and did I forget to mention, wind and solar electric power creates zero emissions in the process, a truly clean option.

Biofuels is another option that is rapidly building momentum. In 1999, total sales of biodiesel in America totaled about half of a million gallons. In 2006, less than ten years later, sales topped 250 million gallons, an increase of 500 fold. Today, in Kentucky, Indiana, Illinois, and Ohio, there are over 150 million gallons of existing production capacity. Also as of today, there are nearly 290 million gallons of additional production capacity under construction in the same four Midwest states. According to the National Biodiesel Board, if this trend continues, by 2012, the biodiesel industry will create nearly 40,000 new jobs in all sectors and keep nearly $14 billion in America that would otherwise be spent on foreign oil, much of this being diverted back to family farms which we all know need it now more than ever. And this is just biodiesel. Ethanol is experiencing the same type of growth. Imagine,

with existing infrastructure, we have the ability to grow our own fuel. But you don't have to imagine, it's happening as we speak.

Coal-fired power plants are not the only way to create new jobs in our area. Coal-fired power plants are not the only way to bring economic prosperity to our area. Coal-fired power plants are not the only way to provide reliable energy for our future.

Please, for the health, safety and prosperity of not only current but also future generations, I urge you to deny this permit for the Cash Creek generation facility and to consider other, truly clean options.

The gentleman from Carbondale and the gentleman from Lexington and the gentleman who just recently spoke, I will have to admit I do understand, I do believe what they are saying that IGCC is the cleanest available technology for burning coal into fuel, but I also truly believe that clean coal is an oxymoron. No matter how you burn it, coal is dirty. There are other clean options out there. And I urge you to, please, explore those other truly clean options. Thank you.

MR. MORSE: Heidi Krause.

MS. KRAUSE: Hello, my name is Heidi Krause and I'm a resident of Evansville, Indiana and a former resident of Newburgh, Indiana.

My concerns about this plant are the same as Valley Watch and of other concerned citizens against the Crash Creek plant. This plant will create more poor air quality than what we have now. Regardless of the facts the emissions are lower, it still doesn't mean we will have any less emissions. I'm asking for the good of Henderson County, Vanderburgh County, Warrick County, and all and any other surrounding counties, please do not allow this permit or this plant to be built here.

MR. MORSE: Thank you. Bob Gober.

MR. GOBER: Thank you for the opportunity to speak. My name is Bob Gober and I'm a resident of Warrick County, Boonville, Indiana. The net gain of permanent jobs is minimal. It's too heavy of a price to pay with our air quality. No matter how low emission, thermal efficient this plant is, the fact is there's still pollution being added to our area. With the EPA lowering for air quality standard, if this project proceeds, Warrick County, Indiana will be crippled with

non-attainment problems. A few permanent jobs will have a greater negative impact on your northern neighbors, specifically Warrick County. I respectfully ask you to not allow this permit.

MR. MORSE: Thank you. Bob Messick.

MR. MESSICK: Greetings, my name is Bob Messick from Newburgh, Indiana. I feel like I'm speaking to my neighbors in Henderson. As a neighbor we share many activities. We have many similar interests, primarily we like outdoor activities, good health, clean air, and namely an environment in which we can raise our families. We also have many activities that we have in common, we shop across the river from each other. We have entertainment facilities that we both use. We like the festivals, the river activities we use, display the river, display the environment and keep it clean. We share restaurants, we share educational facilities so that we can raise our families in this society in which they can improve their quality of life, but most importantly we share medical facilities. A single trip to Welborn is obvious the many problems are produced by the bad air that's here. We see asthma. We see allergies. We see headaches. And we see a lot of

cancer. Very common. And I respectfully ask that this permit be refused on the basis that it really has a net deficit to our environment.

I worked for 17 years in the nuclear admission industry, the product was TALES (phonetic), which is the specter annual that we had to hide, and as we all know from the news that we read, TALES are pretty hard to hide and they're going to be with us forever. The same holds true for C02 in the environment. There's no valid safety in performing the C02 to prevent future global warming. Thank you.

MR. MORSE: Thank you. Wendy Bredhold.

MS. BREDHOLD: Hi, I'm Wendy Bredhold and I live in Evansville. I'll just speak from my heart because I haven't prepared anything.

I don't know how many members of the Air Quality Division live or reside in this area, but ever since May of this year I think we've had at least a dozen, ozone in particular, alerts already. It's not even July. We already have so many days in which we're told that sensitive population should stay indoors. And the sensitive population include children and active adults. Who's healthier than children and active adults?

And those are the people that are told to stay inside. I mean, it's a little surreal to be standing here and asking you not to allow another power plant in this area because we're already so overwhelmed with pollution that we're told to stay indoors for what is it going to be, all summer? And this is okay? Is it okay to be told to stay indoors all summer? Is that the way we want our children to live? And how will our grandchildren live that way?

I remember -- well, I grew up all over the country in the Air Force. I didn't grow up in this area. I never heard of asthma until I moved to Evansville, Indiana. I didn't know any little kids who had respirators or had to worry about running and getting out of breath and being sick. And it's okay to live like this for a handful of temporary jobs? And then we've got all these other people who want to build power plants here because for some reason it's okay. It's okay to do that here?

Here on the front page of today's paper, Peabody looking to build another plant, they've got Edwardsport. Who's next? Because we'll allow it, while other parts of the country

say no. We don't want it. You do it. We'll take the energy, as the gentleman said. It's okay here? I don't think it's okay. And I hope that you don't allow it. Thank you.

MR. MORSE: Richard Stewart.

MR. STEWART: Hello, I'm Richard Stewart. I'm a member of local 181, operating engineers, Henderson, Kentucky. I've worked in most every power plant in this area. I'm a father, grandfather, I'm in my fourth -- four and a half years recovering from small cell carcinoma of the right lung. September the 28th, last year, I had a heart attack; October 29th, I had a stroke. I've collapsed my left lung twice.

While recovering from cancer, 34 radiations to my chest, 21 weeks of chemotherapy I never stopped working and I worked at power plants all over this country, Evansville, Princeton, TBA, Hallsville, Big Rivers at Sebree. I fought cancer, so far I've won.

And we hear our brothers and sisters across the river in loud voices, pleasant voices talking about the particulates, clean up your own backyard. General Electric is the worst polluter in the nation. More particulates per million than any other chemical plant in this nation. It's time. They know a lot. And I helped put scrubbers on at GE to take care of the pollution. People of Southern Indiana, Northwestern Kentucky, do you-all realize what the kill ratio is from the Mount Vernon GE plant if something happens serious; 35 miles, probably 70 percent. I helped put scrubbers on in Gibson County, Petersburg, Hallsville, Sebree, TBA over the last four and a half, five years while battling lung cancer. January I started my fifth year of recovering from lung cancer.

I would like to see Cash Creek built because of the coal gasification. It is going to be the cleanest thing going. We need the power. Yes, this power might end up in California, New York, Canada.

I think in 1997 there was a study that came out that we needed 485 new power plants put into production to maintain our present rate of round outs nationwide. So, yes, coal-fired power plants are dirty, nasty, but if I can recover from a killer working in power plants -- and I run heavy equipment. I get to play with the big toys. I play with big cranes and big dosers and about everything else in between. I've got three grandchildren, five children and they live in this area.

So we need the jobs and the power and I really -- TBA Power, I'm working at TBA right now, they've got 30 units. There is no telling on God's green earth where that power goes to. Rockport plant, that power goes to Chicago, Detroit, it all points north. We've got 17 power plants and I've help put scrubbers on four or five of them so far this last four, five years and I've been fighting cancer and I'll continue to fight and I'll continue to work at power plants. Thank you.

MR. MORSE: Wallace McMullen.

MR. MCMULLEN: I'm Wallace McMullen, energy chair of the Kentucky Chapter of the Sierra Club. Thank you for the chance to speak.

My comments, this plant will aggravate air quality problems. We've heard about the Indiana counties directly north of both plant locations, Warrick and Vanderburgh, they're already non-attainment and point vertical. This plant will aggravate the already existing air quality problems there. Please note that both the Warrick County Commissioners and Newburgh Town Board have passed resolutions opposing Cash Creek due to its impact on the Warrick County non-attainment area. Nearby Evansville, as several residents have said, a metropolitan area with over 100,000 residents will also be seriously impacted by the proposed facility.

Further, the EPA has tightened the ozone standard. When the standard is tightened to 70 or 75 parts per million from the current 84 parts per million, Warrick and Vanderburgh counties will be further from meeting clean air standards, and Daviess County in Kentucky will be in non-attainment with 70 parts per million.

Permitting this plant to pump 965 tons per year of carbon monoxide, 700 tons per year of NOx, plus volatile organic compounds, plus hazardous air pollutants, plus sulfuric acid mist into the air in this region is just making the air quality hole worse for these counties and their residents are already stuck down in.

This plant will be bad for human health. The pollutants this plant will emit will impair the air quality and have a negative impact on the health of people living within the affected airshed. Pollutants such as NOx, SOx and sulfuric

acid mist, as we've heard, will aggravate asthma problems, tend to increase cases of cardiovascular disease and increase heart attacks.

EPA's consultants estimate that the fine partial pollution from power plants shortens the lives of 745 Kentuckians each year. Kentuckians already have the second highest risk in the country of dying from power plant pollution. Statewide, the fine particle pollution from power plants also causes 16,440 asthma attacks every year, 998 -- or 798 of which are so severe they require emergency room treatment with associated loss of workdays and schooldays.

Based on EPA data, each year there's 110 lung cancer deaths and 1,000 heart attacks in Kentucky that are attributed to power plant pollution. The studies done by ABT Associates indicate that four premature deaths pre year may result from pollution emitted by this Cash Creek plant alone.

No one needs the electricity from this plant. Being built as a merchant, proposed solely for the speculative premise of the time it's built, they can sell electricity on the open market for a profit. ERORA does not have a defined service area

containing customers for this plant. If it's not built, no one will suffer a lack of electricity.

It will aggravate global warming. It's going to put out three to four million tons per year of carbon dioxide. Folks, that's global warming pollution. As global warming worsens it's already causing serious health and economic problems in the region. For one example the heat wave of 2005, killed 4,000 feed lot cattle in Kentucky. We've observed the disaster of Hurricane Katrina strike New Orleans. We currently have massive flooding in Texas. We watched Lake Tahoe burning down this year.

The current proposal claims to be capture ready, capture this carbon dioxide but they're actually not going to do it. The proposal does nothing to deal with the crucial question facing the entire coal industry. Whether a large scale carbon sequestration can work and if coal can have a future in a carbon constrained world.

Kentucky needs jobs from efficiency and

from cleaner renewable engineering, not permitting more air pollution from dirty coal power plants.

Now, I have a 24 page letter from our attorney with associated attachments addressed to

you, Mr. Morse, I assume you'd liked me to hand it to the court reporter?

MR. MORSE: Yes.

MR. MCMULLEN: I also have a 13 page supplemental comment I've written myself which I do not propose to read through this lengthy meeting and I'll hand these to the court reporter. Thank you.

MR. MORSE: Tom Bodkin.

MR. BODKIN: Mr. Chairman, my name is Tom Bodkin. I'm an attorney from Evansville, Indiana. I'm counsel for the town of Newburgh and special counsel for the Warrick County Commissions and I'm here and like to speak on behalf of those two entities and also for myself, I'm a resident of Newburgh. In fact, I live about a thousand yards from the Kentucky boarder. I can see it everyday.

Recently the Commonwealth of Kentucky issued a draft title V potential construction permit to build a new coal-fired merchant power plant as we know called Cash Creek in eastern Henderson County. That plant is approximately 16 miles from my house and my town. In fact, we'll be able to see the stacks from the power plant if, in fact, it's built. The permit allows them to

increase, as we understand them, various pollutants. It will increase air pollution problems in Newburgh and Warrick County since we are directly downwind from those facilities. Warrick County, as you've now heard, already fails to meet health standards for fine particulate matter and we're very near the margins for ozone. In fact, we've recently had several ozone workdays as you've now heard and I'm not sure how many, but several, and those ultimately, if they continue are going to drive us into further non-attainment status. We are now non-attainment on particulate matter. We're very close to being non-attainment on ozone. If Cash Creek is allowed to be built we believe that we will then be forced into a position of being non-attainment on ozone.

The town Newburgh and Warrick County has long, long favored and approved economic development from a reasonable standpoint. The investment through the town and county infrastructure to allow for development has been massive, in the tens of billions of dollars. But to promote economic development at the cost of degraded air quality is both shortsighted and frankly, ultimately, in no ones best interest.

Major developments will not locate in non-attainment areas. All we have to do is look across the river at Vanderburgh and Warrick County, look at all the businesses who have not located there because they're non-attainment. They may move north, but they're not locating in non-attainment areas.

If this power plant is built we strongly believe that Henderson County will likely become a non-attainment area itself, therefore, the believed economic development it would get from this plant will, in fact, not occur.

There's additional incentives to protect and improve air quality as someone mentioned a moment ago, EPA recently has lowered the 24 hour PM2.5 standard. We're already not in compliance with that. And they've indicating they're going to lower the ozone standard from 85 parts per billion to about 70. If that happens Warrick County will be in non-attainment for ozone as well. If the ozone standard is revised our quality -- air quality does not improve, then the metropolitan statically area, of which Henderson County is a part I might add, will ultimately face what we face in the Warrick and Vanderburgh

counties in Indiana and that is future economic growth will not only be stifled, it will be stopped.

There are a number of things we would request that you consider with regard to this proposal. We ask that the Commonwealth of Kentucky voluntarily take the following measures to protect air quality through our region, this is a region all of us, both in Indiana and Kentucky, call home. First, require rigorous pollutant control and reduction strategies, require coal-fired power plants to utilize the most advanced technology available to capture carbon and control and/or reduce solutions of nitrous oxide, sulfur dioxide, volatile organic compounds and all the other pollutants consistent with the implementations of Clear Air Interstate Rule .2010, the Clean Air Visibility Rule .2015. The Clean Air Written Rule .2020.

Secondly, conduct pre-construction and post-construction monitoring to acquire data for ozone and PM2.5 and to do it not only in the areas that are non-attainment in Indiana but also in at least Webster and Henderson County so that you have the necessary baseline to determine whether or not

this plant will, in fact, cause this county and your neighbors to the north to be further polluted and create further difficulty. We would also suggest that monitoring not be limited to new PS DSR sources. It should also be required to include any facility in those areas which actually or potentially emit a hundred tons per year of nitrous oxide, sulfur dioxide and volatile organic compounds.

Lastly, we suggest that you should perform air quality impact modeling specifically for the counties in the SMSA and those outside the SMSA that will be impacted by this plant. We believe that the average modeling should be performed, in addition perform modeling for each of the individual facilities. Modeling is not a perfect science but we understand that it is the best predictive available at this time.

The town of Newburgh and Warrick County commissioners are the elected officials who represent electively some 60,000 people in that part of the world. The town of Newburgh has about 4,000 citizens, the county has approximately 60. In 2001, the town of Newburgh adopted a resolution regarding this power plant and at that point

opposed it for the same reason they opposed it today, that is, we do not believe it's been adequately studied. I would request to enter into the record the resolution from 2001, for the town council of Newburgh which I call Newburgh Number 1.

Secondly, town council recently adopted -- I'm sorry it was number 2. Adopted number 1 the resolution of 2007-08, that resolution was adopted unanimously by the town council on the 13th of June again opposing this power plant. I will offer into your record Warrick County commissioners resolution 2007-5, resolution passed in August of 2005, opposing this plant and the county commissioners again adopted that same resolution just recently in 2007 and I will offer that into your record as well. If I may.

MR. MORSE: Yes.

MR. BODKIN: I've lived in that town roughly 33 years. This year, for the first time, we saw bald eagles flying down the Ohio River. I think that's significant. It may not -- has to do with air quality I submit to you because when I moved here you didn't find sparrows flying down the Ohio River. Gentlemen, please take into account

the resolutions representing some 60,000 people right on the boarder of this county just across the river. Thank you.

MR. MORSE: Thank you. John Blair.

MR. BLAIR: My name is John Blair. I'm here representing the group Valley Watch which is a public health and environmental group. Its purpose is to protect the public health and environment of the lower Ohio River Valley. We've been in business since 1981 and I would like to say that things are getting better, but it seems like lately things may be getting worse.

I heard -- I overheard from the hall a while ago when one of the people who are against this plant stood up and said they were an environmentalist and somebody kind of derisively said tree hugger I heard in the hall. Well, you know, there's nothing wrong with those trees to begin with and I'm not here as a tree hugger, I'm here as a parent hugger, and a child hugger. These people are under assault by the air quality that we have here regionally. And to prove that, in 1998 a study was done by the Tristate Partners for Health, which was a business group connected with the University of Southern Indiana and they found that

a child with asthma was five times -- a child nine to thirteen in Evansville, was five to -- five times more likely to have asthma than his counter part in Fort Wayne. The reason for that is really simple. We're surrounded by power plants. Lots of power plants. Three of the biggest power plants in the United States, the Paradise power plant, the Gibson power plant and Rockport power plant combined, I'm looking here as far as carbon dioxide is concerned, combined those power plants put out a little over 50 million tons each year of carbon dioxide, the principle greenhouse gas. All of them put out lots of carbon dioxide and, in fact, this plant will, too.

It wasn't very well stated in the statement of basis as to how much coal they would actually burn. I couldn't find that in the statement of basis so I'm taking an estimate from the Edwardsport plant which is the same size. And what they're saying in their filed testimony before the Indiana Utility Regulatory Commission is that they will be putting out four to five million tons of carbon dioxide each year.

Carbon dioxide is a direct impact to our health. In fact, we breath it out every time

we breathe, but it is something that's going to cause us a great deal of problems down the road and I think that several people have addressed that aspect, including Mr. Thompson who kind of made the statement more is less and used Gallagher as an example and talked about dispatching of power plants and how this plant will actually save on pollution because it's adding to the pollution. And I'm not quite sure how he figures that Cash Creek, a merchant power plant that is selling its power on the open market to certain people, is going to be able to replace the Gallagher plant which is owned by an investor owned utility with a defined service area that has plenty of power to meet their customers' needs, but in any case.

I think it's also important to note that Mr. Thompson's testimony is kind of driven by something most people keep in our wallets, money. His group, the Clean Air Task Force, has accepted over three-quarters of a million dollars from the Joyce Foundation for one singular purpose and that is to promote the whole idea behind integrated gasification combined cycle power plants all over the midwest. You can't separate money from advocacy. Except in Valley Watch's case where we

operate with an entirely volunteer staff and have for all but two years of the 25 years we've been in existence.

As Ms. Bredhold said, we've been -- very eloquently I might add, we've been under some form of pollution alert for most of this nice summer that we've had so far. From May 21st through about the same time in June, June 21st, we were under one air pollution alert after another.

Now, these air pollution alerts don't get issued in Henderson because the EPA didn't follow their own guidance whenever they designated counties as non-attainment or attainment. The guidance that EPA has for issues of those designations is that every county in the same metropolitan area be treated equally. Well, somehow or another because region four comes to Henderson, region five comes to Evansville and separated by a river, that designation didn't happen and the metropolitan area, the standard metropolitan statistical area which was supposed to be treated equally was not. So Evansville was designated, Evansville, Warrick County in particular were designated as non-attainment in the first round for ozone and fine particles and then we petitioned to get out of the ozone designation and we have improved our air quality somewhat in the region because of the NOx syp-cal which took place in 2001 and has been implemented pretty much ever since. And we've been fortunate enough to get it down to the design value now of 78 parts per million, I'm sorry 78 parts per billion as a design value and compared to Henderson which is 73 parts per billion and Daviess County, Kentucky 74 parts per billion. The EPA just issued a proposed standard last week and the range that they're taking comment on is from 70 parts per billion to 75 parts per billion. But that kind of aligns something because their Clean Air Scientific Advisory Committee and their own scientific staff had recommended a maximum air pollution standard for ozone of being 70 parts per billion because that is the place that health effects significantly start to occur when it gets to a certain level. So here we are at 74 in Daviess, 73 in Henderson and 78 in Evansville and this plant is going to cause us all to go over, so this may be the last element that we have in any of this region and that's unfortunate.

Carbon dioxide, like I said four and a half million tons is an awful large amount of carbon dioxide, but you don't know -- and I'll go back to ozone for a second. I'm sorry, I jumped ahead.

Ozone is one of the most significant issues that you have to deal with in this permit, but you Mr. Markin, you, Mr. Morse, did not require them to even undertake an ozone analysis. That is one of the most bizarre decisions I've ever heard of. Whenever you have two counties just north of you that are struggling not to be non-attainment, of course you should have required an ozone analysis to determine what kind of impact this plant will have on ozone in those area. Why you didn't is beyond me. I think I know why you didn't actually. It's because you knew what you'd find. You knew that this plant would not pass muster if you allowed -- if it was built if you really did an ozone analysis. So you were completely derelict in your duty not requiring an ozone analysis in this permit. And the statement of basis saying, well, it didn't have enough VOC is kind of disingenuous since the NOx syp-cal dealt with NOx, not with VOC and that's what brought us down from being in the 90 parts per billion level to the 78 parts per

billion level, in deed.

One man said, I think it was the guy from Lexington that works for the state of Kentucky, which we know really likes coal, they rely on the severance tax for coal, the counties rely on the severance tax for coal and, you know, that gives a huge incentive for Kentucky to permit coal-fired power plants because the more coal that's dug out of this state, the more money certain counties have locally.

You can hold that up, but I haven't talked nearly as long as John Thompson so far.

So, in any case, if we're talking about these incentives for state government and local government to promote coal, we understand why this is happening, but it doesn't make it right. What you're doing is basically wrong because you're relegating the people downwind of this facility to ill health, to stroke, to heart attack, to cancer, and I guess you can work in these plants and get those things and still support it, but I don't quite understand the rationale for thinking that way, especially when coal is not the answer to our energy problem, efficiency is.

Kentucky has almost no efficiency

programs going. They like to talk about it and they throw a few bones here and there, but they don't -- they aren't taking anything seriously in Kentucky about dealing with efficiency. They certainly aren't dealing with renewable energy the way they should and conservation. There's no effort on the part of Kentucky that I can ascertain that's going out and telling the people in Kentucky ways and methods of being able to conserve their energy, to eliminate the need for additional coal-fired power plants, you know and -- we know what's happening in eastern Kentucky, with mountain top removal it's the most insidious, despicable environmental and ecological collapse that's ever been done and somehow state government is allowing all that to take place.

So it seems that these guys that want to come in here, want to come in here for one good reason, they've got almost nine hundred million dollars of GE money and hedge fund money to promote their dirty work. None of those people that I know of are going to live here, Mr. McGinnis or Mr. Schwartz or any of these people are going to live here. They're going to be far away. Probably resting in their resorts, counting the money as it comes in.

You know, we really do encourage you to take another look and especially demanding Cash Creek do a thorough ozone analysis because that is a glaring omission from this permit.

I have submitted testimony from Carol Overland, as her personal representative, I've submitted testimony from Meleah Geertsma, from the Environmental Law and Policy Center who wrote testimony for Valley Watch, the Sierra Club and the Environmental Law and Policy Center and I hope that you will take the time to read it. Thank you very much.

MR. MORSE: Gary Osborne.

MR. OSBORNE: Good evening. My name is Gary Osborne and I reside in Owensboro, Kentucky. I'm the business manager of the International Brotherhood Electrical workers, local 1701 and also the secretary/treasurer of the Owensboro area of building and construction trade council. Our council has jurisdiction in nine counties in Kentucky, including Henderson. We represent 19 affiliate crafts, local unions, and approximately

10,000 working families. Many of our affiliates have jurisdiction in Southern Indiana with a portion of their membership residing in Southern Indiana.

Our council strongly supports the construction of Cash Creek Generating Facility to be located in Henderson, Kentucky. The proposed 630 megawatt integrated gasification combined cycle facility is the most advanced and largest gasification project under development in the United States. This project would produce fewer air emissions, would use less water and be capable of providing power for 400,000 homes. Prior to one shovel of dirt being turned on the project the developers of the project has made a substantial commitment to the communities of Southern Indiana and Western Kentucky.

First, the project was completely redesigned moving away from the standard coal burning power plant to an IGCC facility for the sole purpose of reducing emissions to our communities. This commitment added millions of dollars to the cost of the facility but was deemed necessary by developers in order meet the demands of the citizens. This will be the cleanest IGCC plant in the United States.

Secondly, the project owners have

committed to the use of a local construction work force by entering into project labor agreements with the local building trades. By entering into such an agreement, this will prove to have a tremendous economic impact in the region. The agreement means several thousand long-term, high paying construction jobs for the local construction work force. It means career opportunities for local youth within the apprentice programs, the commitment by the project owners also means that every construction worker who is employed on the project and also the families will have healthcare insurance at a time when many families are losing their employer sponsored healthcare benefits. Jobs that provide such benefits are important, not only to those families receiving the benefits, but also the local healthcare facilities providing the services.

It means millions of dollars pumped into the local market area weekly. These high paying construction jobs, which is projected to peek at 1,200 to 1,500 construction workers, could pump as much as a million five hundred thousand weekly into our economy. Plus the hidden benefit of healthcare dollars into the local economy. With no large construction projects locating in our area of Western Kentucky in over 20 years these construction jobs are badly needed. Dollars earned in this community by citizens of this community stays in this community. Dollars made locally and spent locally turns over seven times in a community.

Not only will construction workers benefit, the local home builders, real estate market, local car dealers, banks, retail, sales, healthcare facilities. All businesses will benefit from this project, as well as local government and schools. Millions of dollars of tax revenue will come back to local government and, in turn, the citizens of the community will, once again, benefit through increased tax revenues.

Businesses come to states anymore with their hands out, selling out to the highest bidder, in most cases their only commitment to the community is to do what's absolutely necessary to receive their incentives. On nearly every occasion there's no commitment to utilize the local citizens in the construction of the projects. The project owners of Cash Creek have committed in writing to local construction work force. This is much more

commitment to our community than a majority of our local industry has committed to either new or existing.

Today the Cash Creek developers have not been offered one dime for tax incentives to locate to Henderson County or, for that matter, Kentucky. However, they have committed to spending millions of additional dollars to produce a much cleaner facility and have also committed to the utilization of the local work force.

Third, the generation of electricity is needed in our area. The Western Kentucky area does not have an abundance of power available. The negative impact of such is a loss of good paying industrial prospects that cannot even consider the Western Kentucky area for location. With the exportation of our good paying industries to low wage countries, there are very few opportunities for any area to land good manufacturing jobs and what few opportunities exist must not be lost because of lack of power availability.

Kentucky is currently the third largest coal producing state in the United States. Kentucky must take advantage of their abundance of natural resources available. The location of the

Cash Creek plant in Henderson County will not only create 1,200 to 1,500 temporary construction jobs, it will also create 150 to 200 high paying power plant jobs and to operate and maintain the plant along with the creation of mine and mine related jobs which would also be high paying jobs.

I would ask that you don't turn your back on the cleanest coal burning plant in the United States. Kentucky has the resource, Western Kentucky and Southern Indiana need the jobs in this area, the United States needs the power. On behalf of our members we offer our strong support and urge you to support the project. Thank you.

MR. MORSE: Ernest Whitehead.

MR. WHITEHEAD: I'm Ernest Whitehead of Benton, Kentucky and we live in the lake area and a lot of people have problems with breathing. We believe that it's important to check the EPP caps on the web to look at the ozone and fine particulate data. We've done that almost everyday for the last month or so. I really believe that for improving efficiency of power plants, I think the combined cycle idea is the best way, however, I also believe that to add efficiency you look at temperature entropy diagrams to add feed water

heater open and closed types into cycles in order to improve efficiencies, and also I believe that perhaps it's best to oppose this just because at this point in time we just have too many particulates and too much ozone and an additional power plant, I feel, would be completely unwarranted and that concludes my comments. Thank you.

MR. MORSE: Thank you. Corinne Whitehead.

MS. WHITEHEAD: I am Corinne Whitehead, president of Coalition for Health Concern. This is a nonprofit environmental advocacy organization founded in 1985.

On behalf of the members of the Coalition for Health Concern in Kentucky and Southern Illinois, we take this means to express our opposition to the construction and operation of the Cash Creek plant. Please place our comments in the record.

Until Kentucky takes action to control the smog and acute air pollution, which is partially attributed to coal-fired power plants, no additional coal-fired plants should be built in this state. The cost are acute.

Kentucky does not have a power insufficiency. Kentucky must not assume the health damage and cost for power that is to be exported to other regions by merchant power plants.

The health of Kentucky citizens and our neighbors across the river, trumps the excuse for additional power plants. I'll give an example of what we know about a person, a Catholic sister in our county became ill, the doctor did x-rays and asked her how long she had smoked. Her reply was never. Her lungs were described as those of a heavy smoker. She died. Another friend of long-standing has to have oxygen at home full time and when she leaves her home. It's ridiculous to go to a restaurant and see people with portable oxygen and it's all because of the pollution and the crud in the air. The increase in asthma attacks among youngsters has increased dramatically.

The visible smog has increased over the past four or five years. Many days the visibility is dramatically impaired when one tries to even look across Kentucky lake. A remote sensing study, which I was a party to some years ago, was made on the effects of air pollution, on the oak and hickory forests in our region, and the damage is

extensive and included in the air and down.

In addition to mercury, anthracene, and other pollutants, has the cabinet or EPA tested for radiation in Kentucky coal? It is well-known that natural uranium is found in the Chattanooga shale from the Ohio River east of the Appalachian Mountains. We feel that the draft permit fails to protect the citizens' health and must be denied. Thank you.

MR. MORSE: Thank you. Carol Oglesly.

MR. OGLESLY: My name is Carol Oglesly

and I'm a resident of the greater Evansville area.

Basically what I would like to say is very simple. I am a member of Valley Watch and I do strongly support their position as well as the Sierra Club's position on this matter. I strongly encourage this community to deny the Cash Creek power plant.

MR. MORSE: Thank you. Rock Emmert.

MR. EMMERT: Thank you. My name is Rock Emmert and I appreciate the opportunity to be invited, first of all, as a resident of Indiana. I live up in Dubois County, it's about an hour and a half drive down here. I'm on the southern edge and I'm a teacher at Forest Brook High School, an

English teacher.

And first of all, I'd like to say that this -- there's been a little discussion tonight about the Indiana, Kentucky thing and it's about us. We're all in this together. Illinois, every region in the world that has this sort of issue going on and I think that's a point that needs to be stressed of -- if you look at the globe from a distance we're one little spec on this planet. We're all brothers and sisters. I have close friends in Kentucky and relatives in Louisville and I understand this company is based in Louisville, I believe.

But, anyway, I grew up in Ferndale (phonetic), I'm 45 years old, been teaching 24 years. I went away to grad school in Vermont and I thought I was -- I graduated near the top of my class and I thought I was pretty intelligent and I thought I was pretty aware and I get to New England where they have fairly strict laws and I realized that our region of the country is, what's the word I want to use that's kind. They call Southern Indiana hicks and I hear that all the time. Kentucky, you know, the Indiana, Kentucky jokes and I thought, well, they're just talking. Well, I

started to do more scientific research and I do think that our region of the country is a laughing stock of a good portion of the country and I'm a part of that. I'm very much a part of that.

As an English teacher I also have a profound respect for science and the preponderance of evidence is that what we're doing to our area just doesn't make any sense for the long term. And

I respect the need for jobs, but I've got to believe that we can create jobs, all of you in this room, we can create jobs for all of us in this room and all of our families that's clean and that makes sense for the long term.

John suggested at a meeting I attended recently, most of us eat food that travels over a thousand miles from a grocery store. We live in the most fertile part of the United States, the green belt, we have all this land and what if we use some of our construction skills to build huge greenhouses and the existing coal plants divert some of that heat in those greenhouses in the winter and become the produce capitol of the United States. Talk about jobs and income and reputation, and dealing with the global warming question. I mean that's just one suggestion. And I don't know,

I'm not a scientist, I'm not in politics, I don't know all the studies but I think we can do better.

And another coal plant, even this method, as so many people before me said just doesn't make sense, especially when we don't need the energy here. Solar, wind, as we're driving across the bridge at Owensboro a while ago looking out at that river, and I was up in Niagara Falls a couple weeks ago, we have power right here in this river. And I don't know much about hydroelectric, what that would do to the environment but, man, that river is moving 24/7, the sun is shining 24/7. And we're not the greatest wind area of the United States, but we have some wind and it could offset some of the -- if we had a hearing on wind versus solar and hydroelectric, electric or other means I'm just curious if we here in this part of the country would have the turnout that we have tonight. I would hope so because I think the direction of the world is moving in that direction.

And Toronto's headlines on TV when I was up there said they're reducing their coal plants in the entire Province of Ontario from four down to zero in ten years. I mean, there's a picture on the TV of one of the giant stacks come crumbling down. One of my friends who was with me, said, "Oh, my God, I've never seen anything like that before in my life." But that's their goal within ten years to have it down to zero and it just strikes me a little behind the times for us to be here tonight. And I appreciate everybody's concern, but I, for one, am of the opinion that this is not wise for the long-term. It's going to create short-term jobs, we've heard that a lot tonight.

Texas had nine coal plants in the works and that project was recently bought out by a solar and wind firm and I don't know all the details about it, but that was headlines in the news about a month ago. And the governor of -- or the mayor of either Houston or Dallas fought the coal idea and she, with a lot of other people, won, and they're using renewable resources. And that, too, creates a lot of jobs.

I think we need to get with the rest of the enlightened people on the planet and use our energy in our schools, in our resources, our great colleges in Kentucky, Indiana and Illinois and start looking at -- it's not going to happen

overnight -- but start looking at something that is long-term for our children and our grandchildrens' sake. So I would strongly urge all of you who have the great responsibility of making this decision to keep that in mind. And great respect for everybody who's spoken before me, too. I know this is a difficult issue. So thank you.

MR. MORSE: Gary Brown.

MR. BROWN: Good evening, I'm Gary Brown. I live in Daviess County. I've been on this planet about half a century and I've spent half of it one mile growing up next to a power plant. The other half, I think I've probably lived within 30 miles of nine other plants. I'm pretty healthy. I'm not going to say that they're the best thing in the world. You're not going to have clean energy, it's just not possible or it's just impossible, but we have an opportunity, this could be the point where we become the leaders. We're wanting to build the cleanest advanced technology power plant in the country as far as coal burning.

MR. MORSE: Mr. Brown, face the court reporter.

MR. BROWN: I'm sorry. The only other opportunity is some people mentioned wind, well,

that might work in Kansas and other places, but I'm not too sure about here. They mentioned hydro.

Okay, well, let's build a dam down below Evansville and watch the rest of you people from Indiana move to Kentucky where it's a little higher ground because you'll be basically flooded in that area. So anyhow, we're talking about the cleanest burning power plant in the country. I think it's an opportunity and I just believe it's an opportunity we can't pass up. It's not for economic reasons. These other plants that we have in this area are not going to continue to run. Most of them are as old as I am.

The gentleman from Carbondale mentioned Gallagher, I'm not sure where it's at, I believe it's in Indiana somewhere, but he mentioned 80 hours of reduced generation would equal the emissions of what this plant would put out for the whole year. Well, that's pretty significant. If we can eliminate that and Rockport and -- well, Gibson is doing their thing as far as putting in the scrubbers up there, but they're not quite there yet, but now that I've mentioned these three plants here, they happen to all be in Indiana. I think as one other guy mentioned, clean up your own

backyard. And if anybody pays any attention to which direction the wind blows and where the weather comes, it comes from the southwest going northeast. Well, I live directly in line with this plant, I'm fixing to build a home for my five, seven and twelve year old girls and it's going to be directly in line with this plant, does it bother me, well, you might think I'm going to be ignorant because I'm saying no, because I'm used to being around power plants. However, the point I'm trying to get at is that we do have an opportunity to be leaders in the world and not the laughing stock, you know. We can send a message to everybody else in this county that we're building clean power, as clean as possible.

But I am also curious to know, had a lot of people speak up here, seems like most of the people that are speaking are in opposition and a lot of us construction workers are not exactly speakers. So I'd just like to know, people that are in favor of this plant would you please raise your hand. Thank you. I think that's a significant number right there in itself.

And to close this, like I said, I'm not really a speaker, but I'm also not exactly uneducated. I have over 22 years of education and training, a couple degrees to go along with that. So thank you for your time.

MR. MORSE: Thank you. Carly Watson.

MS. WATSON: I've already spoken.

MR. MORSE: Oh, you signed in twice.

MS. WATSON: Maybe somebody signed me in by accident. Can I bring up waste water?

MR. MORSE: I didn't hear the question.

MS. WATSON: I said can I bring up waste water?

MR. MORSE: If you'll speak to me after this hearing I'll be happy to direct your comments to the appropriate party.

MS. WATSON: Okay.

MR. MORSE: Ben Taylor.

MR. TAYLOR: Good evening. My name is Ben Taylor and I live in Daviess County, the village of Maceo.

I want to, to save time, I want to speak about my concern about global warming. Although the design of this plant makes it theoretically possible to sequester C02 emissions, there's no proposal that will actually do so. In fact, it's yet to be demonstrated that C02 sequestration is either technically feasible or economically viable. The dangers posed by burning vast quantities of fossil fuels are well established scientifically and by now is familiar to most citizens. Warmer temperatures, melting glaciers, reduced snow cover in northern latitudes, thawing permafrost with the accelerate release of large amounts of heat trapping methane gas, rising ocean levels with extensive coastal flooding, disruptions of agriculture, loss of entire ecosystems as well as the extinction of numerous individual species, more damaging hurricanes and tornadoes, and the spread of topical diseases and pests into formerly temperate regions are all part of the global warming scenario described in scientific literature, popular books, and one Oscar-winning documentary film.

Although the global warming scenario is by now rather familiar, we must admit that we can scarcely imagine or predict the full extent of economic harm or ecological destruction. Unless mankind, led by heavy emitters of greenhouse gases like the United States, can make drastic reductions in emissions, the earth will be unable to avoid the most serious consequences of global warming. It's

impossible to predict all the consequences and the potential for unforeseen disasters due to interaction between novel geophysical conditions and greatly stressed biological systems seems to be unacceptably large. We're wandering into uncharted territories. We only have one earth to destroy. Once it is cooked, we are done. Personally I prefer the adoption of policies that move us toward the sustainable use of resources. Thank you.

MR. MORSE: Thank you, Mr. Taylor. That concludes the list of people who indicated they wish to speak tonight. Is there anyone else whom would like to speak now? Come forward.

MR. WEYER: Yes. I'd like to give everybody a little heads up on who I am, my name is Cliff Weyer from Southern Indiana up in Dubois County. I'm a land owner in a couple different counties up that way.

I am currently living in Vermont right now, and I'm a teacher of sixth, seventh and eighth grade students in middle school and I can clearly say that I used to be in an audience like this, totally different spot from where I am now.

Through my course of studies at Indiana State, I have learned an immense amount of

information on technologies that are related to alternative energy. And in Vermont they don't think twice about objecting to something like this. They have a different mentality than westerns, midwesterns I found out.

When I took this job, as a teacher at Southern Vermont I was asked to teach the kids alternative energy. Now, right now China is one of the leading countries in industrial growth. They have many, many, many more dirty power polluting plants than we do here, and they're looking for two states to help them out of the United States, out of all 50 states, they're asking California for help to clean up their coal plants and also Vermont. So I think that the position I'm in, being from the area, leaving, living in Vermont, breathing the clean air, should be taken into consideration.

I really would appreciate if we can take some of this energy in this room, in this part of the country and turn it into something that can help foster education of the masses, try to get people aware of conservative energies. There are many, many more solutions. I just read this week about a company, they are in Canada, they have a

900 acre solar panel farm they're starting. 900 acres. That's a very, very small amount of land compared to what's here. You've got options, there are other ways. There are many other ways.

I would also like to enlighten some of you, I will guarantee that a very small percentage of the people in this area, this room know about this. I'm using 75 percent of renewable energy in Vermont. 75 percent of my electric bill every month comes from renewable cow pow. The farms in Vermont, the dairy farms in Vermont are extremely small compared to what we have here. Very, very small. This is just one option. One option. Take some of your farms in the local area, give it a try. There's government help out there. There are other options that will use less detrimental, I guess, properties. Give it a thought.

I've been the construction worker, my

family owns a huge, huge company, I've been there. Here sitting in this room I would like to make you aware that construction work for this project is temporary. It's a very short project according to how long you might be working.

That's about all I have to say. I want to thank everyone for getting up here and speaking

and I'm really glad to be here, as I didn't even know this was going to occur. I'm just from Vermont for a very short time. Thanks.

MR. MORSE: Frank Travatto, you've indicated you wanted to speak.

MR. TRAVATTO: Yes. My name is Frank Travatto. I'm a member of local 40 boilermakers Elizabethtown, Kentucky. I live in Henderson County, I have two young sons, nine and five, that go to school in this area. I've lived here most of my life. I think as long as this plant meets the EPA guidelines as far as safety and other issues that it should be built to create jobs in this area. I've worked all over the country, I've heard these people in the Evansville area. I have worked at Rockport, Warrick, Gibson County and the work that we do we are exposed to a lot of these asbestos, fly ash that has lead, nickle, a lot of safety things that ran in on these outages. Someone has to do it. We use safety guidelines as far as we can to get by with them, but we've been up in it and so has all my life.

I am in favor of this plant and that's all I have, sir, thank you.

MR. MORSE: Thank you.

MR. VANDIVER: My name is Garland Vandiver. I've lived in Henderson County almost 50 years.

MR. MORSE: Sir, would you spell the last name for our reporter.

MR. VANDIVER: V-a-n-d-i-v-e-r. I'm for the plant. Henderson County needs the work for economical reasons. People from Evansville and Newburgh are saying they're downwind from this new plant, most weather maps I've ever seen the wind blows west to east, not north to south or south to north. And I hope that somehow that -- I'm getting too old to work in construction, I may give it a try, but for kids that are growing up here in this town, we need some more things to keep them here in this part of the country. Thank you, sir.

MR. MORSE: Thank you. Is that everyone then.

MR. MCCORMICK: I won't keep you guys very late. I've got to be in the power plant in the morning, in Newburgh as a matter of fact. Adam McCormick. I say from the young people's standpoint, this power plant is going to be a good thing for this area. I have a 97-year-old grandmother that lives five miles from the Big

River Power plant. She's still very active. You know, we can all come up with scenarios where everybody is a statistic, you know.

MR. MORSE: Give us your name.

MR. MCCORMICK: Adam McCormick. I just think this thing, this power plant would be a good thing for this area. That's all I've got. Thank you.

MR. MORSE: Come on up.

MR. ARNOLD: My name is Jim Arnold. I live in Vanderburgh County. I'm a boilermaker by trade for 30 years in December. The job a boilermaker does, like other brothers and sisters in this room, we build pollution control equipment, SCRs, precipitators, scrubbers. We got done building the SCR and a scrubber on unit 30, powerhouse stain plant. Also, the plants in Big River systems have put in new pollution control systems. I'd like to know, that this study that the other group was talking about, how old is that study? Because it should be updated. By us putting in these new pollution control systems at these power plants, it should help the quality of air.

And one more thing, I'm in favor of

Cash Creek. Kentucky has got a chance to show the nation, the commonwealth does, to show the nation that we are involved in clean air environment. So I am in favor of this power plant. Thank you.

MR. MORSE: Thank you.

MR. WEST: Hello, my name is Tim West. I work at the Big River facilities and just like the other gentleman said earlier, we spent millions of dollars on pollution control, NOx reduction, SOx reduction, it's a daily factor. I've heard all these things about the air attainment in Warrick County right across the river.

I was a young child at the time but I remember when they built a powerhouse on this side of the river and the Indiana bat was on the endangered species list. I guess once they moved the powerhouse across the river they grilled that Indiana bat, maybe, so I think that Mayor Weinzapfel across the river -- but I heard a lot of people say you can't get industry in Indiana because of the air attainment, but I don't know if you're buying or selling, but I'm for this fire house on this side of the river Kentucky style for jobs and economic development. And that's all I've got to say about that. Thank you.

MR. MORSE: Thank you.

MR. BURTON: My name is Truman Burton and I'm a resident of Ohio County and I live about four miles downwind from the Kansas power plant, been there two decades. I also live about 20 miles of three other powerhouses. One thing that kind of struck me here about this meeting is looking at the cross section of individuals that make it up. I want to remember as a young child listening to John Kennedy say, you know, "ask not what your country can do for you, but what you can do for your country." And that's why I support the new technology that goes into this plant and I support building it. Because I feel like along with other new technology on the renewable wind and solar and other research, I feel like that the new technologies of the future is what will bring us to future energy independence and will bring our soldiers home from Iraq, which is a high priority with me right now, and it possibly could avoid future war, major war that involves a lot of different countries. I think new technologies in our future, like this plant involves, can give us a chance to avoid some of the things that could go wrong in our future.

I appreciate your all time and for listening to me and I hope that you'll have God's speed in looking at these different issues that come before you and that you'll make a decision that will be good for America. And I'm willing to sacrifice, if possible, risk to my family and me by living around powerhouses and supporting new technologies that comes along to help us get out of our energy problems. Thank you.

MR. MORSE: Anyone else.

MS. MARK: I'm Carol Mark. I'm a resident of Daviess County. I'm a native of Niagara Falls, New York. We used to be, although I'm not sure right now, but we used to be the hydroelectric power capitol of the world. And I go home occasionally to see my friends and one of the things that they're frightened about most is a terrorist attack. We talked about air quality and jobs, but no one has ever said with so much concentrated electrical power in this area, how much of a risk are we involved in in terms of a terrorist attack. I live with that everyday of my life. My son works in London, England, and today they found a bomb. I live with that everyday. So, that's my concern. Nobody has brought that up.

One of the people here said there were 17 power plants in this area. Not a bad sight for somebody who wants to take on a lot of energy that's going to go to California, in Michigan, Chicago, just think about that, that's a thought. It's not to do with air quality, although we may end up with poor air quality if we get nuked.

MR. MORSE: Thank you.

MS. LATHAM: My name is Susan Latham, L-a-t-h-a-m. I live here in Henderson and I work in the healthcare field here in Henderson.

It saddens me greatly that we do not have any children in this room that suffer from asthma and that will continue to suffer and suffer more and we will have more children added to that number right here in Henderson. There is a huge burden on the doctors in this county because of problems that we already face. And it's been in our paper that we are the unhealthiest or the 49th unhealthiest state in the union. It just blows me away that we do not put that as our top priority when we consider this.

People that say that they think it's great that this company is here because they have committed to union workers, you can see, visually

see why they are saying that. They are assured of a total base support if they say that that's what they are going to employ. People who can't figure out why they're not asking for tax breaks, they do not need tax breaks. This state does not have laws that would keep companies like this out of our state like other states have. That's why they're coming to us, folks, because we have no way to keep them out. We do not make the laws because for us health is not our priority. Thank you.

MR. MORSE: Okay. If you've made an oral statement or not you are still welcome to submit written comments tonight. After this public hearing closes we won't be accepting official comments. Yes.

MR. COULTER: My name is David Coulter and I live in Evansville. I know that may be a word to some people in this room. I'm an avid fisherman. I like to fish, eat the fish that I catch but in Indiana we have fish consumption advisory for every single surface water resource in the entire state. Every creek, every river and every lake in the entire state. And it comes as a result of airborne mercury that comes from all the coal that is burned in the coal-fired power plants all through this region. You-all got the same problem over here but you don't talk about it as much. I submit to you that that probably is the most important, I mean aside from the air quality and everything else, mercury is a much more toxic substance than ozone or SO2 or NOx or any of the others. Mercury kills. It causes brain damage. It causes neurological disorders. And I can't eat the fish in Indiana because of the mercury. And, yeah, they're talking in Congress about trying to put some caps on things and trying to clean up the mercury and get it out of the air, but they haven't done it yet and I still can't eat my fish in Indiana. I don't know about you-all here in Kentucky, I imagine the situation is the same over here. And it ain't going to get any better because mercury in your water is cumulative over time, just like PCBs, just like dioxin and all the other toxin substances that we know about. So I really wasn't going to say anything but if you want to have more mercury in your fish go ahead and build this plant.

MR. MORSE: Thank you. Okay. We're going to take the time to address all of the air quality related comments that we take home with us tonight and the ones that are received during the

30 days of public comments preceding this hearing. When the permit is proposed to the EPA, comments that were received and the response to the comment

will be made available on our website, WWW.AIR.KY.GOV and if you want to see me after to get that, I'll be happy to write it down for you. It will be available here in the county clerk's office, and at the Owensboro Regional office. You can also obtain it by contacting us directly at 502-573-3382 or by mailing a request to the Division for Air Quality, Permit Review Branch at 803 Schenkel Lane, Frankfort, Kentucky 40601.

Those of you that are still with us, thanks for coming tonight. This public hearing is now closed.

(PROCEEDINGS CONCLUDED AT 9:10 P.M.)

(UNLESS OTHERWISE NOTIFIED BY THE PARTIES INVOLVED, THE TAPED RECORDING MADE IN CONNECTION WITH THE TAKING OF HEARING WILL BE DESTROYED SIX MONTHS FROM THE DATE OF HEARING.)

COMMONWEALTH OF KENTUCKY)
)SS:
COUNTY OF DAVIESS)

I, Catherine Passmore, Notary Public, State-at-Large, do hereby certify that the aforegoing deposition was taken at the time and place set forth in the caption thereof; that the witness therein was duly sworn on oath to testify the truth; the proceeding was reported by me stenographically; and the aforegoing is a true and correct transcript to the best of my ability.

I further certify I'm not a relative or employee of attorney or counsel of any of the parties hereto, nor a relative or employee of such attorney or counsel, nor do I have any interest in the outcome or events of this action.

I hereby certify that the appearances were as stated in the caption.

DATED THIS 9TH DAY OF JULY, 2007.

CATHERINE PASSMORE, NOTARY PUBLIC
STATE-AT-LARGE
OHIO VALLEY REPORTING SERVICE
202 WEST THIRD STREET, SUITE 12
OWENSBORO, KENTUCKY 42303

COMMISSION EXPIRES:
September 13, 2009
DAVIESS COUNTY, KENTUCKY

This transcript has been reviewed by DAQ personnel, and air quality related comments that were raised during the public hearing have been previously addressed in this document. There are three air quality related questions that have not been previously addressed. These questions are excerpted verbatim and answered below:

From Christine Belt, transcript page #10

On page 27 of Cash Creek's permit statement of basis it reads the division has not required the application to include an air quality impact analysis for ozone. I ask, why not?

Division's Response:

Regulation 401 KAR 51:017, Section 7.(5) (a) states, in part: "No de minimis air quality level is provided for ozone. However, a net increase of 100 tons per year or more of volatile organic compounds subject to this administrative regulation is required to perform an ambient impact analysis including the gathering of ambient air quality data." Since the total VOC emissions from the Cash Creek project are less than 33 tpy, no ambient air quality impact analysis for ozone is required.

From Christine Belt, transcript page #11

I ask, how can 391 tons per year of sulfur dioxide released into the air not have an adverse impact? Sulfate dioxide is the main component of acid rain, which has a very adverse affect on vegetation and crops.

Division's Response:

See response to comment in Appendix F numbers 1 and 2 of this document.

From Corinne Whitehead, transcript page #65

In addition to mercury, anthracene, and other pollutants, has the cabinet or EPA tested for radiation in Kentucky coal?

Division's Response:

In the 'Study for Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress' dated February 1998 (EPA-453/R-98-004a), U.S. EPA concluded that "the risks due to exposure to radionuclide from utilities are substantially lower than the risks due to natural background radiation." (page ES-23)

ATTACHMENT K

Supplementary TDS Concentration Analysis from Cash Creek dated September 28, 2007

September 28, 2007

Mr. Ben Markin
Combustion Section Supervisor
Permit Review Branch
Department for Environmental Protection
Division for Air Quality
803 Schenkel Lane
Frankfort, KY 40601

RE: Draft Permit Number V-07-017
Source Name: Cash Creek Generation, LLC
Source I.D. #: 21-101-00134

Dear Mr. Markin:

This letter is in response to a query from the Permit Review Branch related to potential reductions of Total Dissolved Solids ("TDS") in the Cash Creek Generation, LLC ("CCG") cooling tower circulating water.

Background:

The quantity of Particulate Matter ("PM") emissions from the CCG cooling tower is dependent on three operating parameters: circulating water flow rate, liquid drift loss, and the TDS concentration in the liquid drift. The circulating water flow rate (375,000 gpm) is set by process cooling needs and can not be reduced to control PM emissions from the cooling tower. A Best Available Control Technology ("BACT") analysis was performed in the permit application to select high efficiency drift eliminators (99.9995% efficiency) as BACT respecting liquid drift loss. The purpose of this letter is to demonstrate that the remaining parameter, TDS can not be cost-efficiently reduced in terms of BACT ($/ton of emissions reduction) to reduce cooling tower PM emissions at the Cash Creek Generating Station.

Potential TDS Control Approaches:

Two control technology/operating approaches can be used to reduce TDS concentrations in cooling tower circulating water in order to reduce TDS concentrations in liquid drift. The first option involves demineralizing cooling tower make-up water in a water treatment plant to remove TDS. The second option involves reducing the Cycles of Concentration ("COC") in the cooling tower to avoid concentrating TDS as water is evaporated from the cooling tower.

Technically Feasibility:

CCG believes that both options are technically feasible to reduce TDS concentrations in the liquid drift in order to reduce cooling tower PM emissions.

Control Effectiveness of Control Approaches:

Option 1, demineralizing cooling tower make-up water, can theoretically reduce TDS concentrations to less than 1ppm in liquid drift. For purposes of this analysis, CCG has assumed that this option would result in no PM emissions from the cooling tower. This assumption is very aggressive in that it ignores PM that would result from erosion, corrosion, degradation of cooling tower fill, and the low levels of TDS that would persist in demineralized make-up water.

Option 2, managing cycles of concentration, could reduce TDS concentrations to a level that approaches the TDS concentration of CCG's cooling tower water supply source. CCG's water supply will be withdrawn from the Green River and then clarified to remove Total Suspended Solids ("TSS") prior to introduction to the cooling tower. After clarification, the TDS concentration in the supply water will be approximately 310 ppm. For purposes of this analysis, the control effectiveness of this option is assumed to be fifty percent (50%) as compared to the engineering design of the CCG cooling tower (7 COC), or 3.5 COC. This option reduces PM emissions from the cooling tower by fifty percent as compared to CCG's permit application. The impact of reducing COC is increased water usage.

Option 2A, represents managed COC consistent with CCG's permit application. In this option, the cooling tower is operated at seven (7) COC consistent with good engineering practice related to corrosion management, thermal efficiency, and diminution of cooling water consumption.

The following table delineates the cooling tower PM emissions that result from each control option.

Option	TDS Concentration	Annual PM Emissions
1. Demineralized CT Make-up	Assumed to be 0 PPM	0 tons/year
2. Operation at 3.5 COC	1,150 ppm	4.73 tons/year
2A. Operation at 7 COC	2,300 ppm	9.45 tons/year

Economic, Environmental and Energy Impacts:

Economic Evaluation:

Option 1 involves significant capital expenditures and incremental operations/maintenance expense. To assess incremental capital expenditures, the demineralizer for process water at CCG was upgraded from 849 gpm throughput to 5,784 gpm (849 gpm for process water and 4935 gpm for cooling tower make-up). This increase in demineralizer size results in an incremental capital expenditure of $41.05 million. Use of a capital recovery factor of 0.094393 yields an annual capital recovery expense of $3.87 million. Incremental operations/maintenance expense for this option (as compared to Option 2A) is $1.85 million annually. Therefore, the total incremental annual cost associated with Option 1 is $5.72 million.

Option 2 will require additional capital expenditures to address increased water handling capability and potential changes to cooling tower fill or reservoir sizing. However, a detailed engineering analysis of cooling tower design and pump, valve, and piping cost would be required to delineate the incremental capital cost. Therefore, this analysis assumes that no material capital cost increase would be incurred to implement this option. However, this option does result in incremental water usage of 1,000 gpm or 525,600,000 gallons/year. Water supply expense (energy and operations/maintenance) at CCG is $500/million gallons. Therefore, the annual incremental cost associated with Option 2 is $262,800 if capital cost impacts are ignored. CCG has also ignored incremental water treatment chemical cost and additional solid waste handling cost that would be associated with handling an additional 525 million gallons of water annually.

The average cost effectiveness of each alternative is depicted below.

Option	Annual PM Emissions (tons)	Increase in Annual Cost	Annual Average Cost ($/ton)
1. Demineralized CT Make-up	0	$5,720,000	$605,291
2. Operation at 3.5 COC	4.73	$262,800	$55,678
2A. Operation at 7 COC	9.45	Base	Base

The incremental cost effectiveness of each alternative is shown below.

Option	Decrease in Annual PM Emissions (tons)	Increase in Annual Cost	Incremental Cost ($/ton)
1. Demineralized CT Make-up	4.73	$5,457,200	$1,153,742
2. Operation at 3.5 COC	4.72	$262,800	$55,678
3. Operation at 7 COC	Base	Base	Base

Environmental Evaluation:

Option1 involves removing TDS from all cooling water. This removal would result in incremental solid waste production of 3,285 tons/yr based on capture of the 310ppm of TDS in the clarified cooling tower make-up water.

Similarly, Option 2 would produce an incremental 175 tons of solid waste annually. This increase is due to removal of Total Suspended Solids ("TSS") in the inlet water clarification system for the incremental 525 million gallons of water that would be consumed annually. That additional water consumption also constitutes a significant environmental impact.

Energy Evaluation:

Both Option 1 and Option 2 require incremental energy consumption as compared to Option 2A. However, given the material economic and environmental impacts described above, CCG has not undertaken an engineering analysis to quantify those impacts.

Conclusion:

As demonstrated by both the economic and environmental evaluations above, reducing TDS to reduce cooling tower PM emissions is not cost-effective in the context of accepted BACT $/ton of emissions reduction values. This is especially true when the environmental impacts associated with increased solid waste production and water consumption are considered. CCG believes that BACT for the Cash Creek Generating Station cooling tower can be accomplished with a 2.16 lb/hr PM emission rate, premised on the following parameters.

- A maximum cooling tower flow rate of 375,000 gpm,
- Drift eliminator efficiency of 99.9995%, and
- A maximum TDS concentration of 2,300 ppm.

If CCG can provide any additional information, please feel free to contact me at 502.357.9901.

Very truly yours,

Michael L. McInnis
Manager
Cash Creek Generation, LLC

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

October 31, 2007

Dr. Donald van der Vaart, Ph.D., P.E.
North Carolina Department of
Environment and Natural Resources
Division of Air Quality
1641 Mail Service Center
Raleigh, North Carolina 27699-1641

Dear Dr. van der Vaart:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit dated August 14, 2007, for a major modification of the Duke Energy Carolinas LLC (Duke Energy) Cliffside Steam Station located in Cliffside (Rutherford County), North Carolina. The draft permit is for the proposed installation of a new pulverized coal electric utility steam generating unit (Unit 6) with a nominal generating capacity of 800 megawatts and supporting equipment.

Based on our review of the preliminary determination, draft permit, and supporting materials (including submittals from Duke Energy), we have developed the enclosed comments. If you have any questions concerning these comments, please call Jim Little at (404) 562-9118 or Katy Forney at (404) 562-9130.

Sincerely,

Gregg M. Worley

Gregg M. Worley
Chief
Air Permits Section

Enclosure

EXHIBIT D

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U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION 4, AIR PERMITS SECTION

Comments on Draft PSD Permit for Duke Energy Carolinas LLC, Cliffside Steam Station, Unit 6 Project

The following abbreviations/acronyms are used in these comments in addition to commonly understood abbreviations/acronyms such as lb for pound and hr for hour:

AQRV - air quality related values
BACT - best available control technology
CEMS – continuous emissions monitoring system
EPA - U.S. Environmental Protection Agency
gr/dscf - grains per dry standard cubic foot
MMBtu -million British thermal units
MSBD - minor source baseline date
NAAQS - national ambient air quality standards
NCDAQ - North Carolina Division of Air Quality
NOV - Notice of Violation
NSPS - new source performance standards (federal standards in 40 CFR part 60)
NSR - new source review
PSD - prevention of significant deterioration
RBLC - RACT/BACT/LAER Clearinghouse
SIA - significant impact area
tpy - tons per year

In addition the following abbreviations are used for pollutants:

NO_x - nitrogen oxides
PM - total particulate matter
PM_{10} - particulate matter with an aerodynamic diameter of 10 μm or less
$PM_{2.5}$ - particulate matter with an aerodynamic diameter of 2.5 μm or less
SO_2 - sulfur dioxide

In the following comments the terms “we,” “our,” and “us” refer to EPA’s Region 4 office. The term “Unit 6” refers to the proposed 800-megawatt pulverized coal electric utility steam generating unit.

1. <u>Netting Analysis</u>

In its preliminary determination supporting the draft PSD permit, NCDAQ provided a regulatory analysis. In this analysis, NCDAQ concludes that PSD review is not required for NO_x and SO_2 emissions from Unit 6 and ancillary units. This conclusion is based on a netting analysis in which emissions decreases from existing Units 1 through 5 are deemed to be creditable for netting purposes. Specifically, the netting analysis for SO_2 is based on emissions decreases from emissions controls on Unit 5 alone with no consideration of decreases resulting from the planned shutdown of Units 1 through 4. The netting analysis for NO_x is based on emissions decreases from emissions controls on Unit 5 plus emissions decreases from the planned shutdown of Units 1 through 4.

On May 9, 2000, EPA issued a notice of violation (NOV) to Duke Energy Corporation alleging, among other issues, that Duke Energy undertook illegal modifications at Units 1-5 of the Cliffside facility. On December 22, 2000, the United States Department of Justice (DOJ), on behalf of EPA, filed a complaint against Duke Energy in the United States District Court for the Middle District of North Carolina. An element of the case was subsequently appealed to the Fourth Circuit Court of Appeals, and then again to the United States Supreme Court where it was ultimately resolved in favor of EPA in April 2007. The case was remanded by the Supreme Court back to the District Court level for further proceedings, which are currently ongoing.

Pursuant to federal regulations incorporated by reference in North Carolina's PSD rules, a source cannot receive emission reduction credit for reducing any portion of actual emissions which resulted because the source was operating out of compliance. *See* 40 CFR 51.166(b)(3)(vi)(a). With regard to the Cliffside facility, a BACT analysis has not been completed for Units 1-5 for NO_x and SO_2. As a result, if the emissions reductions from the shutdown of Units 1-4 and the installation of additional controls on Unit 5 are less than would result from the installation of BACT controls as required for compliance with PSD permitting requirements, then these reductions are not creditable for use in any netting calculations for Unit 6. *See* 40 CFR 51.166(b)(3)(vi)(a). Depending on the outcome of the aforementioned case before the District Court, the permitting of Unit 6 may be found to have occurred in violation of the law and Duke Energy may be in violation of PSD requirements for construction of Unit 6. We recommend that NCDAQ notify Duke Energy of this possibility before taking final action with regard to the application from Duke Energy for an air emissions permit to construct Unit 6, to ensure that NCDAQ and Duke Energy are fully aware of the potential impact of the ongoing enforcement action.

2. Absence of Total Mass Emissions Limits

For Unit 6, emissions limits in the draft permit are specified solely in terms of lb/MMBtu. However, the draft permit does not include a limit on maximum heat input (MMBtu/hr). A limit solely in terms of lb/MMBtu does not establish an upper limit on hourly total mass emissions unless accompanied by a limit on maximum heat input or total mass emissions (e.g., lb/hr). Therefore, the draft permit does not contain specific emissions limits that match the total mass emissions rates used for ambient impact modeling analysis purposes. The final permit, if issued, should contain either (a) enforceable limits for maximum heat input (MMBtu/hr) as well as enforceable limits in terms of lb/MMBtu, or (b) enforceable limits in terms of both lb/MMBtu and lb/hr. This same comment also applies to the auxiliary boiler.

3. Optional PM Emissions Limits for Unit 6

a. The proposed Unit 6 filterable PM_{10} BACT emissions limit is 0.012 lb/MMBtu. According to the condition in Part I, Section 2.1.J.2.d (page 44) of the draft permit for Unit 6, if the owner/operator of the facility can demonstrate the proposed BACT emission limit for filterable PM_{10} does not "provide adequate margin for regulatory compliance," then NCDAQ may revise the emissions limit not to exceed 0.015 lb/MMBtu. Having a higher fallback emissions limit provides a clear disincentive for Duke Energy to achieve the lower emissions limit established as BACT during the PSD review process. We recommend that the fallback provision should be eliminated, particularly since it is evident that other similar sources are permitted at 0.012 lb/MMBtu (see Item 3.c. below). Having a baghouse with adequate capacity should provide reasonable assurance of compliance with the BACT limit.

b. Furthermore, the condition states that, if the limit is revised to a higher value, "[s]uch a revision shall be a Minor Modification." In accordance with title V permit regulations in 40 CFR 70.7(e)(2)(i)(A)(3), minor modification procedures may not be used for permit modifications that "require or change a case-by-case determination of an emission limitation." In addition, any increase in the established primary BACT emissions limit would require initiation of a PSD permit revision action that might also require further ambient impact compliance modeling depending on the nature of the change compared with the basis of previous modeling. Such increase would also require a 30-day public comment period.

c. In Table 5-4 (page 41) of the preliminary determination, NCDAQ cites the Longleaf Energy project in Georgia and lists a "likely" filterable PM emissions limits for this project of 0.015 lb/MMBtu. The final permit for Longleaf Energy was issued in May 2007. The PM control method is a baghouse. The filterable PM limit in the final permit is 0.012 lb/MMBtu (3-hour) with no provision for a higher fallback limit.

4. Compliance Averaging Times Associated with Emissions Limits

It is unclear in the draft permit what compliance averaging times are associated with the BACT emission limits for all of the emission units in this project. If the averaging times for the BACT emission limits are the same as those associated with the test methods described in the permit, then this should be stated in the permit for clarity. Otherwise, compliance averaging times should be added to the appropriate sections of the permit.

5. Allowable Coals for Unit 6 and Effect on BACT Determination

Based on the information available to us, the proposed new Unit 6 can burn both bituminous and subbituminous coal and use of a particular type of coal is not a fundamental aspect of the project. (Presumably subbituminous coal would include western coals such as Powder River Basin coal.) Although NCDAQ describes Unit 6 in the preliminary determination as being expected to fire "primarily" bituminous coal, the draft permit does not prohibit exclusive use of subbituminous coal. Therefore, under these circumstances, NCDAQ should re-evaluate the entire BACT determination to assess the option of restricting Unit 6 to use of just one type of coal, specifically, subbituminous fuel only or bituminous fuel only. This would be especially important if NO_x and SO_2 emissions were subject to BACT, which they are not in this instance because NCDAQ is accepting that the project has netted out of PSD review for these pollutants. (But see our comments on the netting analysis in Item No. 1 above.) However, the BACT evaluation for other pollutants possibly could be affected if the fuel supply were restricted to one type of coal. We request specifically that further BACT review be performed for particulate matter emissions and sulfuric acid mist emissions assuming the option of burning subbituminous coal only. Furthermore, should the BACT emissions limits change as a result of this further BACT review, the ambient impact modeling analysis might have to be revised accordingly.

6. BACT Emissions Limits for Auxiliary Boiler

According to Table 5-9 of the preliminary determination (page 52) and the condition in Part I, Section 2.1.K.5.b (page 52) of the draft permit, the BACT emissions limit for filterable PM_{10} from the auxiliary boiler is set at 0.014 lb/MMBtu. However, from a search of the RBLC, there are comparable distillate oil-fired boilers of a similar capacity with BACT emission limits lower than those being proposed for the Duke Energy Cliffside auxiliary boiler. For instance, the auxiliary boilers at the Plum Point Energy facility located in Arkansas have a PM_{10} emissions limit of 0.0071 lb/MMBtu. Similarly, the boiler at Virginia Commonwealth University has a PM_{10} emissions limit of 0.0100 lb/MMBtu. NCDAQ should consider adopting these limits or provide an explanation of why the new unit at the Cliffside facility can not achieve these levels.

7. Particulate Matter BACT Limits for Materials Handling Units

In its assessment of PM_{10} emissions limits for material handling operations (coal, lime, limestone, ash), NCDAQ indicates that a review of the RBLC disclosed limits ranging from 0.005 to 0.01 gr/dscf for operations controlled by baghouses. The emissions limits determined to be BACT as listed in Table 5-10 of the preliminary determination (pages 55 - 57) are as follows:

- Limestone (baghouse controlled) - 0.01 gr/dscf (filterable)
- Coal (baghouse controlled) - 0.01 gr/dscf (filterable)

- Ash (baghouse controlled) - 0.01 gr/dscf (filterable)
- Lime (baghouse controlled) - 0.01 gr/dscf (filterable)

NCDAQ does not provide an explanation of why the upper end (0.01) of the RBLC range was selected rather than the lower end (0.005). Properly selected baghouses in many applications can achieve an emissions rate less than 0.01 gr/dscf. NCDAQ should consider adopting a lower limit or provide an explanation of why the new material handling units at the Cliffside facility that are to be controlled with baghouses can not achieve a lower limit.

8. Startup and Shutdown Emissions

Section 5.3.6 (page 48) of the preliminary determination contains a discussion on startup and shutdown emissions for the proposed Unit 6. It is unclear from this discussion whether NCDAQ is establishing separate emissions limits for the boiler during startup and shutdown operations. The draft permit does not seem to contain any emissions limits specifically for startup and shutdown, nor does it seem to contain an exclusion or exemption from the normal operating emission limits during periods of startup and shutdown. The apparent difference between the discussion in the preliminary determination and the contents of the draft permit should be addressed in the final determination and final PSD permit (if a final permit is issued).

9. Particulate Matter Continuous Emissions Monitoring System for Unit 6

In the draft permit, NCDAQ provides for operation of a PM CEMS on Unit 6 as an option. In light of improvements in and wider use of this technology, our recommendation is that operation of a PM CEMS be included as a permit requirement for Unit 6 rather than an option.

10. Cooling Tower Emissions

On page 51 of the preliminary determination, NCDAQ states that BACT for the proposed new cooling tower is a drift eliminator with a drift rate equal to 0.0005 percent of the recirculated water flow. In the draft permit (Part I, Section 2.1.L), however, BACT for the cooling tower is expressed as PM_{10} emissions rates of 12.94 tpy (12-month rolling) and 70.8 lb/day. We find no mention of the drift elimination rate in the draft permit. We recommend that a drift elimination rate design requirement of 0.0005 percent be added to the permit in addition to the PM_{10} emissions limits. In addition, we recommend adding a requirement for recording and reporting of recirculated water flow on some periodic basis, and measurement and reporting on some periodic basis of total dissolved solids in the recirculated water.

11. PM as a Regulated NSR Pollutant

On page 10 of the preliminary determination, NCDAQ states the following: "Also, NCDAQ does not consider 'PM' to be a regulated NSR pollutant and only uses PM as a surrogate for PM_{10}." On page 20, however, NCDAQ lists "particulate matter" as a pollutant regulated under NSPS subpart Da. Since the definition of regulated NSR pollutant includes pollutants subject to NSPS, it is clear to us that PM is a regulated NSR pollutant. We wish to make this position clear as a matter of record. At the same time, our opinion is that NCDAQ's approach to assessing and limiting PM_{10} emissions for this project is adequate for PM as well.

12. Fine Particles

On page 10 of the preliminary determination, NCDAQ cites EPA policy guidance as saying that "States should use PM_{10} as a surrogate for $PM_{2.5}$" until federal $PM_{2.5}$ NSR implementation rules are promulgated. While this is a reasonable depiction of current EPA policy guidance, please note that EPA has also said (in its April 5, 2005, policy guidance memo) that "statements in this policy guidance do not bind State and local governments and the public as a matter of law." Also please note that EPA may issue final $PM_{2.5}$ NSR implementation rules before a final permit has been issued for the proposed project (if NCDAQ decides to issue a final permit).

13. Ambient Impact Assessment

a. Netting Modeling Analyses – Based on the NO_x emissions reduction credits from the shutdown of Units 1-4, and SO_2 emissions reduction credits from the scrubber addition to Unit 5, the project netted out of PSD review for SO_2 and NO_x. Also of importance for the comments below, the decrease in SO_2 emissions from the shutdown of Units 1-4 was not used in the netting analysis. (Duke Energy has asked that these decreased emissions be reserved for possible future use.) One of the requirements for a creditable emissions decrease is that it have "approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change." [40 CFR 51.166(b)(3)(vi)(c)] The following comments are directed at the modeling analyses required by NCDAQ to satisfy this requirement. The purpose of the analyses for SO_2 and NO_x was to demonstrate no "net" negative air quality impact (referred to below as the no-net-negative impact comparison).

(1) The modeling analyses of impacts from the current facility operations and from the future operations after the proposed modification are needed for this comparison. These two station configurations must be modeled using the same air quality model, same meteorology, and same receptor grid. The input station operational data must reflect netting conditions contained in the draft permit.

(2) To demonstrate the netting has no net increase in impact concentrations, both the before and after controlling concentrations should be compared (i.e., highest annual and highest-second-high short-term) as well as the concentrations at each receptor. The percent of receptors with increased concentrations should be part of this evaluation.

(3) Because the NO_x no-net-negative impact comparison modeling was explicitly performed for this application, it appears likely that identical modeling procedures and models were used. Although the modeling files were not available to EPA for confirmation of this presumption, NCDAQ indicated in an e-mail message dated October 24, 2007, that identical modeling procedures were used.

(4) The SO_2 no-net-negative impact comparison analyses used modeling results from the Units 1-4 Stack Extension Project (December 2006) to represent the current station operation. EPA does not know if the 2006 modeling procedures were identical to those reported in the Unit 6 permit application to estimate future station impacts. In addition, the SO_2 netting analysis for the proposed Unit 6 project does not take credit for the decrease in emissions associated with shutting down Units 1-4. Therefore, SO_2 emissions from Units 1-4 should not have been included in the current station modeling for the no-net-negative impact comparison assessment. The concentrations in Table 6.2-1 for SO_2 existing emissions from Units 1-4 plus Unit 5 are not appropriate to demonstrate no net increased impact associated with the proposed emissions netting.

b. PSD Class I Area Analysis – The station emissions used in the Class I area AQRV impact assessment should not be limited to project related increases in PM_{10} emissions used in the PSD increment assessment. The visibility and deposition modeling assessments should include total future station emissions for pollutants (for example, PM_{10}, SO_2, NO_x) affecting the AQRV. It appears that only project related increases in PM_{10} emissions were used in the AQRV assessment.

c. Project Emissions – The short-term project emission rates used in the impact modeling appear to have been based on the annual emission rates. Short-term emission rates are generally higher than hourly rates derived from annual emissions divided by annual operational hours. Where available, appropriate higher short-term emission rates should be used in the modeling evaluation, or the modeled short-term emission rates should be included as permit limits.

d. Inventory of Other Emission Sources – The cumulative PM_{10} NAAQS and PSD compliance assessment included other emission sources within the SIA plus an addition 50 km radial distance.

(1) The PSD permit application did not contain a list of other NAAQS emission sources included in the modeling.

(2) The PSD inventory of other sources is a subset of the NAAQS inventory. Although the 20D procedure was indicated as not used to eliminate PSD sources, the application does not provide a list of PSD inventory sources modeled.

(3) PSD increment-consuming sources are identified based on the appropriate minor source baseline date (MSBD). The appropriate MSBD is that associated with the location of modeled receptors. Because PSD source inventories were provided by four different regulatory agencies, the proper MSBDs may not have been used to identify PSD emission sources. The PSD permit application should have identified the appropriate MSBDs used. Confirmation is needed that the appropriate MSBD (or MSBDs) were used to develop the PSD inventory of other sources used in the modeling evaluation.

(4) The basis (allowable or actual) for the emission rates provided in the NAAQS and PSD inventory of other sources should be provided.

January 14, 2004

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

IN REPLY REFER TO: 4530-1

Mr. Scott A. Patulski
Vice President, Fossil Operations
231 W. Michigan
Milwaukee, WI 53201

Dear Mr. Patulski:

Your application for an air pollution control construction permit has been processed in accordance with sec. 285.61, Wis. Stats.

The enclosed construction permit is issued to provide authorization for your source to construct and initially operate an Electric Generating Facility referred as Elm Road Generating Station - North Site With Accommodations at 4801 E. Elm Road, Oak Creek, Wisconsin in accordance with the requirements and conditions set forth within Parts I and II of the permit. Please read it carefully. This permit expires 90 months after the day this permit is issued. This source may not operate after this construction permit expires unless you have been issued an operation permit.

Enclosed with the permit there are two copies of a bill for the cost of reviewing and acting upon your air pollution control permit. This bill is due and payable within 30 days of the date of the issuance of the permit. Your check should be made payable to Wisconsin Department of Natural Resources and returned to the address on the bill. Please include one copy of the bill with your payment.

A copy of this permit should be available at the source for inspection by any authorized representative of the Department. Questions about this permit should be directed to the Wisconsin Department of Natural Resources,
Wisconsin Department of Natural Resources, Southeast Region, 2300 North Dr. Martin Luther King Jr. Drive, Milwaukee, WI 53212, Phone (414) 263-8500

NOTICE OF APPEAL RIGHTS

If you believe that you have a right to challenge this decision, you should know that Wisconsin statutes establish time periods within which requests to review Department decisions must be filed.

To request a contested case hearing pursuant to s. 285.81, Stats., you have 30 days after the decision is mailed, or otherwise served by the Department, to serve a petition for a contested case hearing on the Secretary of the Department of Natural Resources. Any such petition for hearing shall set forth specifically the issues sought to be reviewed, the interest of the petitioner, the reasons why a hearing is warranted and the relief desired.

EXHIBIT E

For judicial review of a decision pursuant to ss. 227.52 and 227.53, Stats., you have 30 days after the decision is mailed, or otherwise served by the Department, to file your petition with the appropriate circuit court and serve the petition on the Department. Such a petition for judicial review shall name the Department of Natural Resources as the respondent.

This notice is provided pursuant to s. 227.48(2), Stats.

STATE OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES

Raj Vakharia, Review Engineer
Permits & Stationary Source Modeling Section
Bureau of Air Management

cc: SER Air Program Air Program
SER, Sturtevant Service Center Air Program
US EPA Region V
Kathy Zuelsdorff, PSC, 610 N. Whitney Way, P.O. Box 7854, Madison, WI 53707-7854

Enclosure

BEFORE THE DEPARTMENT OF NATURAL RESOURCES
AIR MANAGEMENT PROGRAM
FINDINGS OF FACT
CONCLUSIONS OF LAW
AND DECISION

Findings of Fact

The Department of Natural Resources (DNR) finds that:

1) Elm Road Generating Station (Referred as North Site with Accommodations), 4801 E. Elm Road, Oak Creek, Wisconsin, Wisconsin has applied for an air pollution control construction permit. The authorized representative of the facility is Scott A. Patulski – Vice President, Fossil Operations.

2) Elm Road Generating Station (Referred as North Site with Accommodations), submitted an air pollution control permit application and plans and specifications and any additional information describing the air contaminant source between June 18, 2002 and January 9, 2004.

3) DNR has reviewed Elm Road Generating Station (Referred as North Site with Accommodations)'s air permit application and the plans and specifications submitted to DNR.

4) This permit is for an air contaminant source.

5) DNR has complied with the procedures set forth in s. 285.61, Stats.

6) The proposed air contaminant source meets all of the applicable criteria in s. 285.63, Stats.

7) DNR has complied with the requirements of s. 1.11, Stats., and ch. NR 150, Wis. Adm. Code.

Conclusions of Law

DNR concludes that:

1) DNR has authority under s. 285.11(a), Stats., to promulgate rules contained in chs. NR 400-499, Wis. Adm. Code, including, but not limited to, rules containing emission limits, compliance schedules and compliance determination methods.

2) DNR has the authority under ss. 285.11(a), (e), and (f), 285.27 and 285.65, Stats., and chs. NR 400-499, Wis. Adm. Code, to establish emission limits for sources of air pollution.

3) DNR has the authority to issue air pollution control permits and to include conditions in such permits under ss. 285.60, 285.61, 285.63 and 285.65, Stats.

4) The emission limits included in this permit are authorized by ss. 285.65, Stats., and NR 400-499, Wis. Adm. Code.

5) DNR is required to comply with s. 1.11, Stats., and ch. NR 150, Wis. Adm. Code, in conjunction with issuing an air pollution control permit.

Decision

Elm Road Generating Station (Referred as North Site with Accommodations), is authorized to construct and initially operate an Electric Generating Facility referred at 4801 E. Elm Road, Oak Creek, Wisconsin, as described in the plans and specifications dated between June 18, 2002 and January 9, 2004 in conformity with the emission limits, monitoring, recordkeeping and reporting requirements and specific and general conditions set forth in this permit.

AIR POLLUTION CONTROL CONSTRUCTION PERMIT

EI FACILITY NO. PERMIT NO. 03-RV-166

STACK NO.(S). S18 –S174 SOURCE NO.(S). B18, B19, B20,P62, P63, P64, P175, P76P, P41, P42, P43, B44, T16, T188, T121, T122, T123, T119, T120

THIS CONSTRUCTION PERMIT EXPIRES NINETY (90) MONTHS FROM THE DATE OF ISSUANCE OR WHEN THE OPERATION PERMIT IS ISSUED FOR THE EMISSION UNITS INCLUDED IN THIS PERMIT, WHICHEVER COMES FIRST.

In compliance with the provisions of Chapter 285, Wis. Stats., and Chapters NR 400 to NR 499, Wis. Adm. Code,

Name of Source: Elm Road Generating Station (Referred as North Site with Accommodations)

Street Address:
4801 E. Elm Road
Oak Creek, Milwaukee County, Wisconsin

Responsible Official & Title: Scott A. Patulski – Vice President, Fossil Operations

is authorized to construct and initially operate an Electric Generating Facility described in the plans and specifications submitted between June 18, 2002 and January 9, 2004 in conformity with the conditions herein.

This authorization requires compliance by the permit holder with the emission limitations, monitoring requirements and other terms and conditions set forth in Parts I and II hereof.

Dated at Madison, Wisconsin this 14th day of Januray 2004.

STATE OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES
For the Secretary

By signed by Lloyd L. Eagan
Lloyd L. Eagan, Director
Bureau of Air Management

PART I: APPLICABLE LIMITATIONS

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2

The following emission limits apply to each SCPC boiler.

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.018 pound per million Btu heat input averaged over any consecutive 3–hour period. (Best Available Control Technology, BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08(2), Wis. Adm. Code, s. NR 440.20(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[1] [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters: These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 550 feet above ground evel. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 27 eet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system in combination with a flue gas desulfurization and a wet electrostatic precipitator to meet the BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a).1, Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.A.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The permittee shall perform the compliance emission tests required under condition I.A.1.b.(1) every 24 months within 60 days from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5 or 5B including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code; s. NR 440.20(8)(b)2., Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system at the beginning of each operating shift. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) The permittee shall continuously monitor the operating pressure drop across the fabric filter system and shall sound an audible alarm, whenever the operating pressure drop is below minimum pressure drop identified in I.A.1.b.(5) is exceeded. [s. NR 439.055(1)(b)1., Wis. Adm. Code]

(6) The permittee shall respond to every "out of range" pressure drop alarm in accordance with the provisions of 40 CFR 64.7(d)(1). [s. 285.65(3), Wis. Stats.]

(7) The permittee shall install, calibrate, maintain, and continuously operate a fabric filter bag leak detection system and be equipped with an audible alarm. [s. 285.65(3), Wis. Stats.]

(8) The alarm set point and alarm delay time for each bag leak detection system shall be established during the initial testing period. [s. 285.65(3), Wis. Stats.]

Note 1:The boiler is subject to New Source Performance Standards (NSPS) requirements for particulate matter under s. NR 440.20(3), Wis. Adm. Code and is 0.03 pound per million Btu and 99% reduction when combusting solid fuel. The BACT limit for particulate matter is more restrictive then the particulate matter emission limits under NSPS, thus the boiler is expected to meet the particulate matter emission limits under NSPS.

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[1] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 1. Particulate Matter Emissions [CONTINUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(8) The permittee shall comply with the NSPS compliance determination procedures and methods per s. NR 440.20(6), Wis. Adm. Code and s. NR 440.20(8), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(9) The permittee shall record the output of the fabric filter bag leak detection system. [s. 285.65(3), Wis. Stats.] (10)The permittee shall respond to every bag leak detection alarm in accordance with the provisions of 40 CFR 64.7(d)(1). [s. 285.65(3), Wis. Stats.] (11) The permittee shall comply with the NSPS reporting requirements per s. NR 440.20(9), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM_{10})

a. Limitations: 0.018 pound per million Btu heat input averaged over any consecutive 3–hour period. (BACT) [s. NR 405.08(2), Wis. Adm. Code and s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[1] [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters: These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 550 feet above ground evel. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 27 eet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a).1, Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.A.2.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The permittee shall perform the compliance emission tests required under condition I.A.2.b.(1) every 24 months within 60 days from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5 or 5B including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code; s. NR 440.20(8)(b)2., Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system at the beginning of each operating shift. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) The permittee shall continuously monitor the pressure drop across the fabric filter system and shall sound an audible alarm, whenever the operating pressure drop is below the minimum pressure drop identified in I.A.2.b.(5) is exceeded. [s. NR 439.055(1)(b)1., Wis. Adm. Code]

(6) The permittee shall respond to every "out of range" pressure drop alarm in accordance with the provisions of 40 CFR 64.7(d)(1). [s. 285.65(3), Wis. Stats.]

(7) The permittee shall install, calibrate, maintain, and continuously operate a fabric filter bag leak detection system and be equipped with an audible alarm. [s. 285.65(3), Wis. Stats.]

(8) The alarm set point and alarm delay time for each bag leak detection system shall be established during the initial testing period. [s. 285.65(3), Wis. Stats.]

(9) The permittee shall record the output of the fabric filter bag leak detection system. [s. 285.65(3), Wis. Stats.]

(10)The permittee shall respond to every bag leak detection alarm in accordance with the provisions of 40 CFR 64.7(d)(1). [s. 285.65(3), Wis. Stats.]

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[1] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. **S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2** The following emission limits apply to each SCPC boiler.	
Pollutant: 1. Particulate Matter Emissions less than 10 microns (PM_{10}) [CONTINUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(8) The permittee shall comply with the NSPS compliance determination procedures and methods per s. NR 440.20(6), Wis. Adm. Code and s. NR 440.20(8), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(11) The permittee shall comply with the NSPS reporting requirements per s. NR 440.20(9), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 3. Sulfur Dioxide

a. Limitations: (1) 0.15 pound per million Btu heat input for all periods, including startup and shut down, averaged over any consecutive 30-day period. (BACT) (2) Uncontrolled sulfur dioxide emission rate in the coal shall be limited to 4.0 pound per million Btu, averaged over any consecutive 30-day period. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.20(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]
See Note 1

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation. [s. NR 439.07, Wis. Adm. Code]

(2) Sulfur Dioxide Emissions shall be controlled by the use of wet flue gas desulfurization (FGDS) System to meet the BACT emission limits. [s. NR 405.08(2), Wis. Adm. Code]

(3) The absorber recirculation (AR) slurry flow rate to the wet flue gas desulfurization (FGD) system shall be periodically monitored and maintained within the range specified under condition I.A.3.c.(4). [s. 285.65(3), Wis. Stats.]

(4) (a) The boiler may be fired on coal and/or coal/ash fuel blend, except during periods of start-up and load stabilization when natural gas and/or low sulfur fuel oil may also be utilized as a fuel. (b) The amount of ash fired in the boiler may not exceed 5% by weight averaged over any consecutive 30 day period. [s. NR 405.08(2), Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(5) (a) The permittee shall demonstrate compliance with the coal sulfur limit in I.A.3.a,(2)] by utilizing coal sampling and analysis of the coal as it is shipped from the mine. (b) The permittee shall provide the sampling and analysis protocol at least four months prior to the initial operation of the boiler to the Department for approval. (c) In the event that mine sampling and analysis is unavailable, the permittee shall use as received fuel sampling and analysis procedures in accordance with s. NR 439.08, Wis. Adm. Code to demonstrate compliance with this limit. (d) In lieu of fuel sampling and analysis, the permittee may demonstrate compliance with the coal sulfur limit in I.A.3.a.(2) by using emissions data measured by a continuous emission monitoring system at the inlet to the FGD system. [s. 285.65(3), Wis. Stats., s. NR 439.08, Wis. Adm. Code]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Sulfur Dioxide Emissions: Whenever compliance emission testing is required, US EPA Method 6, 6A or 6C shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used.
[s. NR 439.06(2), Wis. Adm. Code]

(2) (a) The permittee shall install, calibrate, maintain and operate a continuous emission monitoring system, and record the output of the system, for measuring the sulfur dioxide and oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide emissions are monitored. (b) Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75, s. NR 440.20(7)(b), Wis. Adm. Code and s. NR 439.06(4), Wis. Adm. Code. [s. 285.65(10), Wis. Stats.]

(3) The permittee shall use continuous emission monitoring methods and procedures under s. NR 440.20(7)(b), Wis. Adm. Code and s. NR 439.09, Wis. Adm. Code to comply with the NSPS monitoring requirements. [s. NR 439.09, Wis. Adm. Code]

(4) The permittee shall provide to the department, at least 4 months prior to the expiration of the construction permit, information on the operational absorber recirculation (AR) slurry flow rate to the FGD system to be used for monitoring the absorber recirculation (AR) slurry flow rate to the FGD system, as required under condition I.A.3.b.(2), and shall incorporate this information into the Malfunction Prevention and Abatement Plan. (MPAP) [s. 285.65(10), Wis. Stats.]

(5) The permittee shall submit quarterly reports to the Department on the information required under condition I.A.3.b.(5) for each train of coal received during the calendar quarter. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

Note 1: The proposed boiler is subject to NSPS requirement for sulfur dioxide under s. NR 440.20(4), Wis. Adm. Code. The NSPS limit for sulfur dioxide varies depending upon fuel sulfur content, with either a 90% reduction and 1.2 pound per million Btu limitations or a 70% reduction when emissions are below 0.60 pound per million Btu. The NSPS limits apply at all times except during periods of startup, shut down or when emergency conditions exist and the procedures under s. NR 440.20(6)(d), Wis. Adm. Code is implemented. The BACT limits for sulfur dioxide is more restrictive then the sulfur dioxide emission limits under NSPS, thus the boiler is expected to meet the sulfur dioxide emission limits under NSPS.

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler. [CONTINUED]

Pollutant: 3. Sulfur Dioxide (continued)

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(6) The permittee shall demonstrate compliance with the sulfur dioxide emission limits contained in I.A.3.a. (1) Using emissions data measured by the continuous emission monitoring system required by I.A.3.c. (2) as follows: (a) Daily average concentration shall be calculated each calendar day by combining the sulfur dioxide concentration and diluent concentration (in % O2 or % CO2) measurement consistent with the procedures specified in 40 CFR Part 75 Appendix F. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(6) The permittee shall comply with the NSPS reporting requirements per s. NR 440.20(9), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]
(7) The permittee shall perform the compliance emission tests required under condition I.A.3.b.(1) every 24 months within 60 days from the date of the last stack test as long as the permit remains valid. [s. NR 439.075(3)(b) Wis. Adm. Code]	(7) The permittee shall keep appropriate records to comply with permit condition I.A.3.b. (9). [s. 285.65(3), Wis. Stats.]
(8) The permittee shall comply with the NSPS compliance determination procedures and methods per s. NR 440.20(6), Wis. Adm. Code and s. NR 440.20(8), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(8) The permittee shall keep appropriate records to ensure compliance with permit condition I.A.3.b.(4)(b). [s. 285.65(3), Wis. Stats.]
(9) (a) Sulfur dioxide emissions shall be limited to 1,150 pounds per hour averaged over any consecutive 3-hour period and sulfur dioxide emissions shall be limited to 1,050 pounds per hour averaged over any consecutive 24-hour period. These conditions are established to ensure compliance with PSD increments and NAAQS. At these emission rates the air quality standards are expected to be protected. [s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] (b) The permittee shall use the CEMs data to demonstrate compliance with permit condition I.A.3.b. (9)(a). [s. 285.65(3), Wis. Stats.]	

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler
The following emission limits apply to each SCPC boiler.

Pollutant: 4. Oxides of Nitrogen (NOx)

a. Limitations: (1) 0.07 pound per million Btu heat input during normal operation not including periods of startup and shut down, averaged over any consecutive 30-day period. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]; (2) 0.07 pound per million Btu heat input for all periods including startup and shut down, averaged over any consecutive 12-month period. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.20(5)a.1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Notes 1, 2, 3

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[2] [s. NR 439.07, Wis. Adm. Code]

(2) Nitrogen Oxide Emissions shall be controlled using low NOx burners, good combustion practices and a Selective Catalytic Reduction (SCR) System to meet the BACT emission limits. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(3) The permittee shall demonstrate compliance with the NOx emission limit as follows:

(a) NOx emissions shall be calculated based on each 24-hour calendar period.

(b) 24 hour emissions shall be calculated by combining the NOx concentration and diluent concentration (in % O2 or % CO2) measurement consistent with the procedures specified in 40 CFR Part 75 Appendix F.

(c) 12 consecutive months concentrations shall be calculated based on the calculations of the daily concentrations.
[s. 285.65(3), Wis. Stats.]

(4) The permittee shall maintain the ranges of the parameters identified in condition I.A.4.c.(5)a.-d., to meet good combustion practices and/or maintain proper operation of the SCR. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall perform the compliance emission tests required under condition I.A.4.b.(1) every 60 months within 60 days from the date of the last stack test as long as the permit remains valid. [s. NR 439.075(3)(b) Wis. Adm. Code]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Nitrogen Oxide Emissions: Whenever compliance emission testing is required, US EPA Method 7 or an alternate method approved in writing by the Department shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(6), Wis. Adm. Code]

(2) The permittee shall install and operate continuous emissions monitoring systems (CEMs) for NOx and carbon dioxide or oxygen within 60 days after initial start up of the boiler. The CEMs shall be calibrated within 90 days after initial start up of the boiler. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75, s. NR 440.20(7)(d), Wis. Adm. Code and s. NR 439.06(6)(b), Wis. Adm. Code requirements.[s. 285.65(3), Wis. Stats.; s. NR 439.06, Wis. Adm. Code]

(3) The permittee shall certify the CEMs in accordance with 40 CFR Part 75 Appendix A. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) The permittee shall keep appropriate records of the strip chart, round chart or data acquisition (DAS) system/electronic data storage continuously. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(5) During operation, the facility will calculate or continuously monitor and record the unit heat input and the following operating parameters on an hourly basis.
a. Furnace outlet temperature, including SCR inlet temperature, °F
b. Secondary Air Flow
c. Primary Air Flow
d. Fuel Flow Rate
e. Residence Time (by calculation only)
[s. 285.65(10), Wis. Stats.]

(6) During the initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.A.4.c.(5) to establish operational ranges for incorporation into the operation permit. [s. 285.65(10), Wis. Stats]

(7) The permittee shall install, calibrate, maintain and operate instrumentation to monitor the parameters identified by condition I.A.4.c.(5)a. - d. [s. 285.65(3) and (10), Wis. Stats.]

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[2] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler
The following emission limits apply to each SCPC boiler. [CONTINUED]

Pollutant: 4. Oxides of Nitrogen [CONTINUED]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(6) The permittee shall comply with the NSPS compliance determination procedures and methods per s. NR 440.20(6), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(8) The permittee shall comply with the NSPS reporting requirements per s. NR 440.20(9), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.] (9) The permittee shall comply with the general and specific monitoring requirements under s. NR 428.04(3)(a) and (b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (10) The permittee shall comply with all the recordkeeping and reporting requirements under s. NR 428.04(4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (11) The permittee shall comply with all the requirements for monitoring, installation, certification, data accounting, compliance dates and reporting data prior to initial certification as required under s. NR 428.07(1)(b), Wis. Adm. Code, s. NR 428.07(2)(b)2, Wis. Adm. Code, s. NR 428.07(3), Wis. Adm. Code. [s. 285.65(3), Wis. Stats.] (12) The permittee shall monitor NOx and heat input per s. NR 428.08(1)(a), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (13) The permittee shall submit quarterly reports per s. NR 428.09(1), (3) AND (4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(9), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (14) The permittee shall keep appropriate records to show that the boiler is equipped with low NOx burners. [s. 285.65(3), Wis. Stats.]

Note 1: Startup period begins with the firing of fuel and end when the temperature of the flu gas entering selective catalytic reduction (SCR) system exceeds 650 degrees F. The shut down period begins when the temperature of the flue gas entering SCR system temperature drops below 650 degrees F, and shall end with the cessation of fuel firing. Steady state operation is defined as any hour in which no mills are started or stopped or no stabilization fuel is used in the boiler.

Note 2: The boiler is subject to NSPS requirements under s. NR 440.20(5)(a)1., Wis. Adm. Code for nitrogen oxides. The NSPS limit is 0.50 pound per million Btu. The NSPS emission limits for nitrogen oxides apply at all times except during periods of startup, shut down or malfunction. The BACT limit for nitrogen oxides under I.A.4.a.(1), is more restrictive then the nitrogen oxides emission limits under NSPS, thus the boiler is expected to meet the emission limit for nitrogen oxides under NSPS.

Note 3: The boiler is subject to emission limits for nitrogen oxides under s. NR 428.04(2)(a)1.a., Wis. Adm. Code and is 0.15 pounds per million Btu of heat input on a 30-day rolling average basis. The BACT limit for nitrogen oxides is more restrictive then the nitrogen oxides emissions limit established under s, NR 428,04, Wis. Adm. Code, thus the boiler is expected to meet the nitrogen oxides emission limits under s. NR 428.04, Wis. Adm. Code.

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 5. Carbon Monoxide

a. Limitations: (1) 0.12 pound per million Btu heat input during steady state operation, excluding periods of startup, shut down and averaged over any consecutive 24-hour period. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7), Wis. Stats.] See Note 1; (2) 742 pounds per hour excluding periods of startup and shut down, averaged over any consecutive 24-hour period. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7), Wis. Stats.]; (3) 2,400 pounds per hour during any one hour period. [s. 285.65(3), Wis. Stats.] See Note 2; (4) 3,250 tons in any 12 consecutive months for all periods, including startup and shut down. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7), Wis. Stats.] See Note 3

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[3] [s. NR 439.07, Wis. Adm. Code]

(2)Carbon Monoxide Emissions shall be controlled using low NOx burners and good combustion practices to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(3) The permittee shall demonstrate compliance with the carbon monoxide emission limits as follows:
(a) Daily average shall be determined by calculating the arithmetic average of all applicable hourly emission rates for a calendar day.
(b) The hourly emission rate shall be calculated by combining the CO concentration and diluent concentration (in % O2 or % CO2) measurement consistent with the procedures specified in 40 CFR Part 75 Appendix F. The conversion factor, (K), shall be 0.7266 x 10E-7 lb CO/ft3 – ppm.
(c) The annual emission limit in I.A.5.a.(4) shall be calculated using and totaling the hourly calculated emission rate. [s. 285.65(3), Wis. Stats.]

(4) The permittee shall maintain the ranges of the parameters identified in condition I.A.5.c.(3)a.-d., to meet good combustion practices. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall perform the compliance emission tests required under condition I.A.5.b.(1) every 60 months within 60 days from the date of the last stack test as long as the permit remains valid. [s. NR 439.075(3)(b) Wis. Adm. Code]

(6) The permittee shall keep track of the startup and shut down time by monitoring the temperature of the flue gas entering the SCR. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Carbon Monoxide Emissions: Whenever compliance emission testing is required, US EPA Method 10, or an alternate method approved in writing by the Department shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(4), Wis. Adm. Code]

(2) The permittee shall install and operate continuous emissions monitoring systems (CEMs) for CO and oxygen or CO2 within 60 days after initial start up of the boiler. The CEMs shall be calibrated within 90 days after initial start up of the boiler. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 60 Appendix B, and s. NR 439.06(4), Wis. Adm. Code requirements. [s. 285.65(3), Wis. Stats., s. NR 439.06, Wis. Adm. Code]

(3) During operation, the facility will calculate or continuously monitor and record the unit heat input and the following operating parameters on an hourly basis.
a. Furnace outlet temperature, °F
b. Secondary Air Flow
c. Primary Air Flow
d. Fuel Flow Rate
e. Residence Time (by calculation only)
[s. 285.65(10), Wis. Stats.]

(4) During the initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.A.5.c.(3) to establish operational ranges for incorporation into the operation permit. [s. 285.65(10), Wis. Stats.]

(5) The permittee shall install, calibrate, maintain and operate instrumentation to monitor the parameters identified by condition I.A.5.c.(3)a.-d. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(6) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code]

(7) The permittee shall keep appropriate records to show that the boiler is equipped with low NOx burners. [s. 285.65(3), Wis. Stats.]

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[3] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 5. Carbon Monoxide [CONTIUNUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
	(8) (a) The permittee shall keep records to show that they did not exceed the emission limit in I.A.5.a.(2), (3) and (4) and condition I.A.5.b.(3). (b) The permittee shall monitor the temperature of the flue gas entering the SCR and keep records of the flue gas temperature entering the SCR to show compliance with Note 1. [s. 285.65(3), Wis. Stats.]

Note 1: Startup period begins with the firing of fuel and end when the temperature of the flu gas entering selective catalytic reduction (SCR) system exceeds 650 degrees F. The shut down period begins when the temperature of the flue gas entering SCR system temperature drops below 650 degrees F, and shall end with the cessation of fuel firing. Steady state operation is defined as any hour in which no mills are started or stopped or no stabilization fuel is used in the boiler.

Note 2: This hourly emission limit is established to protect the ambient air quality standards.

Note 3: This limit is based on a BACT limit, 0.12 pound per million Btu heat input x heat input of the boiler, 6,180 mmBtu/hr x 8,760 hours/year operation x ton/2000 lbs.

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 6. Volatile Organic Compounds (VOC)

(a) Limitations: (1) 0.0035 pound per million Btu heat input during steady state operation excluding periods of startup and shut down averaged over any consecutive 24-hour period. (LAER) [s. NR 408.04, Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 1; (2) 21.6 pounds per hour excluding periods of startup and shut down, averaged over any consecutive 24-hour period. (LAER) [s. NR 408.04, Wis. Adm. Code, s. 285.65(7), Wis. Stats.] ; (3) 95 tons in any 12 consecutive months for all periods, including startup and shut down. (LAER) [s. NR 408.04, Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 2

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.4 [s. NR 439.07, Wis. Adm. Code]	(1) Reference Test Method for VOC Emissions: Whenever compliance emission testing is required, US EPA Method 25A and/or 18 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(3), Wis. Adm. Code]
(2) VOC Emissions shall be controlled using low NOx burners and good combustion practices to meet LAER limits. [s. NR 419.03, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(2) During operation, the facility will calculate or continuously monitor and record the unit heat input and the following operating parameters on an hourly basis. a. Furnace outlet temperature, °F b. Secondary Air Flow c. Primary Air Flow d. Fuel Flow Rate e. Residence Time (by calculation only) [s. 285.65(10), Wis. Stats.]
(3) The permittee shall maintain the ranges of the parameters identified in condition I.A.6.c.(2)a.-d., to meet good combustion practices (LAER). [s. 285.65(3), Wis. Stats.]	(3) During the initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.A.6.c.(2) to establish operational ranges for incorporation into the operation permit. [s. 285.65(10), Wis. Stats.]
(4) The permittee shall demonstrate compliance with the volatile organic compound emission limit contained in I.A.6.a. as follows: (a) VOC emissions shall be calculated based on each 24-hour calendar period. (b) The permittee shall calculate an hourly average emission rate based on measured data using CO CEMs required in I.A.5.b. (4) by combining the CO concentration and diluent concentration (in %O2 or % CO2) measurement, consistent with the procedures specified in 40 CFR Part 75 Appendix F, in the following equation: VOC actual = VOC limit X (CO actual/CO limit) [s. 285.65(3), Wis. Stats.]	(4) The permittee shall install, calibrate, maintain and operate instrumentation to monitor the parameters identified by condition I.A.6.c.(2)a.-d. [s. 285.65(3) and (10), Wis. Stats.]
(5) The permittee shall provide the following information to the Department for approval at least 4 months prior to the initial operation: (a) Compliance demonstration method that will be used and the records that will be kept to comply with the emission limit in I.A.6.a.(2), and (3). The Department will use this information to write the operation permit. [s. 285.65(3), Wis. Stats.]	(5) The permittee shall keep appropriate records to show that the boiler is equipped with low NOx burners. [s. 285.65(3), Wis. Stats.]
(6) The permittee shall keep track of the startup and shut down time by monitoring the temperature of the flue gas entering the SCR. [s. 285.65(3), Wis. Stats.]	(6) The permittee shall monitor the temperature of the flue gas entering the SCR and keep records of the flue gas temperature entering the SCR to show compliance with Note 1. [s. 285.65(3), Wis. Stats.]

Note 1: The LAER limit of 0.0035 pound per million Btu heat input equates to 21.6 pounds in any hour at maximum output levels. Startup period begins with the firing of fuel and end when the temperature of the flu gas entering selective catalytic reduction (SCR) system exceeds 650 degrees F. The shut down period begins when the temperature of the flue gas entering SCR system temperature drops below 650 degrees F, and shall end with the cessation of fuel firing. Steady state operation is defined as any hour in which no mills are started or stopped or no stabilization fuel is used in the boiler.

Note 2: This limit is based on a LAER limit, 0.0035 pound per million Btu heat input x heat input of the boiler, 6,180 mmBtu/hr x 8,760 hours/year operation x ton/2000 lbs.

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4 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 7. Lead Emissions

a. Limitations: 7.9 pound per trillion Btu Heat Input. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7), Wis. Stats]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[5] [s. NR 439.07, Wis. Adm. Code]

(2) Lead emissions shall be controlled using a fabric filter baghouse system to meet the BACT limit. [s. 285.65(3), Wis. Stats.]

(3) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10 and s. NR 407.09(4)(a)1., Wis. Adm. Code]

(4) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(5) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.A.7.b.(4). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(6) The permittee shall perform the compliance emission tests required under condition I.A.7.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Lead Emissions: Whenever compliance emission testing is required, US EPA Method 12 or Method 29 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system at the beginning of each operating shift. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[5] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

<table>
<tr><td colspan="2">A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.</td></tr>
<tr><td colspan="2">Pollutant: 8. Mercury Emissions</td></tr>
<tr><td colspan="2">a. Limitations: 1.12 pound per trillion Btu Heat Input (BACT, MACT) [s. NR 408.04, Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 1</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[6] [s. NR 439.07, Wis. Adm. Code]</td><td>(1) Reference Test Method for Mercury Emissions: Whenever compliance emission testing is required, US EPA Method 29 or an alternative method approved in writing by the department shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]</td></tr>
<tr><td>(2) Mercury emissions shall be controlled using a fabric filter baghouse system coupled with the use of a FGDs flue gas desulfurization system and SCR to meet the BACT limit. [s. 285.65(3), Wis. Stats.]</td><td>(2) The permittee shall record the pressure drop across the fabric filter baghouse system at the beginning of each operating shift. [s. NR 439.055(2)(b)1., Wis. Adm. Code]</td></tr>
<tr><td>(3) Compliance demonstration identified earlier in this permit for the baghouse system, section I.A.1, and the FGD flue gas desulfurization system, section I.A.3, and the SCR system, section I.A.4, shall be used as compliance demonstration techniques for mercury emissions as well. [s. 285.65(3), Wis. Stats.]</td><td>(3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]</td></tr>
<tr><td>(4) The permittee shall perform 4 stack tests within 18 months of the initial operation and then perform biannual stack test, the first of which shall be performed at the beginning of the initial operation period and every 6 months until the initial operation period has been completed. (b) The permittee shall perform the compliance emission tests required under condition I.A.8.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]</td><td>(4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]</td></tr>
<tr><td>(5) (a)The permittee shall determine mercury emission through coal sampling and analysis. The permittee shall monitor monthly average mercury content and higher heating value in the coal. (b) The data obtained from the monthly coal sampling and analysis shall be correlated with the results of the latest emission compliance test for the purpose of calculating mercury emission rate. [s. NR 405.08, Wis. Adm. Code]</td><td></td></tr>
<tr><td>(6) The permittee shall submit the results of the compliance testing to the Department and the Department will review the test results and adjust the emissions limit to more accurate reduction levels for mercury when the operation permit is issued.
[s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]</td><td></td></tr>
</table>

Note 1: The BACT emission limit for Mercury is based on uncontrolled mercury emissions of 11.2 pounds per trillion Btu and an control efficiency of 90%. The permittee shall achieve process optimization during the initial operation and conduct stack testing for mercury emissions to determine the mercury reduction that is achieved through the use of fabric filter, Wet FGD and SCR system. The Department will use the testing information to adjust the emissions limit to more accurate reduction levels for mercury when the operation permit is issued.

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[6] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 9. Emissions of Fluorides

a. Limitations: 0.00088 pound per million Btu heat input. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7) Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[7] [s. NR 439.07, Wis. Adm. Code] (2) Emissions of fluorides shall be controlled by a fabric filter baghouse system and a FGD system. [s. NR 406.10, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) Compliance demonstration identified earlier in this permit for fabric filter baghouse system and the FGD system, section I.A.3, I.A.1. shall be used as compliance demonstration techniques for fluoride emissions as well. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Emissions of Fluorides: Whenever compliance emission testing is required, US EPA Method 13B shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]

Pollutant: 10. Visible Emissions

a. Limitations: 20% opacity or number 1 on the Ringlemann chart. [s. NR 431.05, Wis. Adm. Code, s. NR 440.20(3)(b), Wis. Adm. Code] See Note 1

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Opacity shall be controlled using a fabric filter baghouse system. [s. 285.65(3), Wis. Stats.] (2) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall install, calibrate, maintain and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. [s. NR 440.20(7)(a), Wis. Adm. Code, s. 285.65(10), Wis. Stats.] (3) Continuous opacity monitoring methods and procedures shall comply with the requirements of s. NR 440.20(7)(a), Wis. Adm. Code and s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code; s. 285.65(3), Wis. Stats.] (4) The continuos opacity monitor (COM) may be located after the baghouse and before the WFGD where condensed water vapor is not present, because the SCPC boilers will utilize wet flue gas desulfurization systems which operate at conditions that will have condensed water vapor present in the flue gas in the stack. [s. 285.65(3), Wis. Stats.]

Note 1: No owner or operator may cause to be discharged into the atmosphere any gases which exhibit greater than 20% opacity (6-minute average), except for one 6-minute period per hour of not more than 27% opacity per s. NR 440.20(3)(b), Wis. Adm. Code.

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[7] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 11. Beryllium

a. Limitations: 0.35 pound per trillion Btu heat input. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7) Wis. Stats.]

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[8] [s. NR 439.07, Wis. Adm. Code] (2) Emissions of beryllium shall be controlled by a fabric filter baghouse system and a FGD System to meet the BACT limit. [s. NR 406.10, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) Compliance demonstration identified earlier in this permit for fabric filter baghouse system and the FGD system, section I.A.3, I.A.1. shall be used as compliance demonstration techniques for beryllium emissions as well. [s. 285.65(3), Wis. Stats.] (4) The permittee shall perform the compliance emission tests required under condition I.A.11.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (5) The permittee shall monitor beryllium emissions through coal sampling and analysis. The permittee shall monitor monthly average beryllium content and higher heating value in the coal. (b) The data obtained from the monthly coal sampling and analysis shall be correlated with the results of the latest emission compliance test for the purpose of calculating beryllium emission rate. [s. NR 405.08, Wis. Adm. Code]. [s. NR 405.08, Wis. Adm. Code]	(1) Reference Test Method for Emissions of Beryllium: Whenever compliance emission testing is required, US EPA Method 29 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system at the beginning of each operating shift. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[8] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A.S18, B18– Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 12. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.

a. Limitations: (1) The permittee shall use fabric filter baghouse and comply with the PM/PM10 limits in I.A.1.a to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall use a wet flue gas desulfurization system (FGD) and comply with the emission limitation of condition I.A.3.a.(1) to meet case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with and meet the VOC emission limits to comply with case by case MACT for organic HAPs [s. 285.65(13), Wis. Stats.]

b. Compliance Demonstration:

(1) Inorganic HAPs emission shall be controlled using a fabric filter baghouse system. [s. 285.65(3), Wis. Stats.]

(2) The compliance demonstration method identified in section I.A.1.b.(6), shall be used as compliance demonstration techniques for inorganic HAPs emission limitations in I.A.12.a.(1). [s. 285.65(3), Wis. Stats.]

(3) Inorganic acid HAPs emission shall be controlled using a wet flue gas desulfurization system (FGD) [s. 285.65(3), Wis. Stats.]

(4) The compliance demonstration method identified in section I.A.3.b.(5), shall be used as compliance demonstration techniques for inorganic acid HAPs emission limitations in I.A.12.a. (2). [s. 285.65(3), Wis. Stats.]

(5) Organic HAPs emission shall be controlled using good combustion practices. [s. 285.65(3), Wis. Stats.]

(6) The compliance demonstration method identified in section I.A.6.b.(2), (3), and (4) shall be used as compliance demonstration techniques for organic HAPs emission limitations in I.A.12.a. (3). [s. 285.65(3), Wis. Stats.]

(7) The amount of ash fired in the SCPC boilers may not exceed 5% by weight averaged over any consecutive 30-day period. [s. 285.65(3), Wis. Stats.]

(8) The permittee shall analyze the ash fired as fuel at least once a year and any time a different coal is used to ensure the fly ash and bottom ash meet the definition of coal and thus the use of this ash is exempt from the requirements of ch. NR 445, Wis. Adm. Code. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs: Whenever compliance testing is required, a compliance test protocol approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]

(2) The permittee shall shall keep appropriate records to demonstrate compliance with permit conditions I.A.12.b.(7) and (8). [s. 285.65(3), Wis. Stats.]

<table>
<tr><td colspan="2">A.S18, B18– Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.</td></tr>
<tr><td colspan="2">Pollutant: 13 Ammonia Emissions</td></tr>
<tr><td colspan="2">a. Limitations: (1) 5 ppm and 20 pounds per hour[9] [s. NR 445.04(1), Wis. Adm. Code]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The permittee shall demonstrate compliance with applicable ammonia hourly emission limit by performing a stack test using USEPA conditional test Method 027, within 180 days after initial start up of the boiler[10].
(a) Compliance emission tests shall be conducted at 100% load operation.
(b) If operation at the 100% load is not feasible, the source shall operate at a capacity level that is approved by the Department in writing. [s. NR 439.075(3), Wis. Adm. Code]
(2) The permittee shall perform the compliance emission tests required under condition I.A.13.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Ammonia:</u> Whenever compliance testing for ammonia is required, USEPA Method 027, or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]</td></tr>
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[9] These emissions do not result from combustion. Aqueous ammonia is used as the reagent for the SCR. Ammonia that does not react is exhausted out of the stack.

[10] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18– Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 14. Sulfuric Acid Mist

a. Limitations: 0.010 pound per million Btu heat input, based upon a 24-hour average. (BACT) [s. NR 405.08(2), Wis. Adm. Code]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[11] [s. NR 439.07, Wis. Adm. Code]

(2) Sulfuric acid mist emissions shall be controlled by a FGD system and wet electrostatic precipitator system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(3) The boiler may only be fired on coal and/or ash fuel blend, except for periods of start-up and load stabilization when natural gas or fuel oil may also be utilized as a fuel. [s. NR 405.08(2), Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(4) The permittee shall perform the compliance emission tests required under condition I.A.14.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. NR 439.075(3)(b) Wis. Adm. Code]

(5) The absorber recirculation (AR) slurry flow rate of water to the FGD system shall be periodically monitored and maintained within the range specified under condition I.A.14.c.(2). [s. 285.65(3), Wis. Stats.]

(6) The sulfur content of fuel oil to be used during periods of start-up and load stabilization may not exceed 0.003% by weight. [s. 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(7) During the initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.A.14.c.(5) to establish operational ranges for incorporation into the operation permit. [s. 285.65(10), Wis. Stats.]

(8) The permittee shall maintain the ranges of the parameters identified in condition I.A.14.c.(5)a.-d., to meet good combustion practices. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Sulfur Acid Mist Emissions: Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]

(2) The permittee shall provide to the department, at least 4 months prior to the expiration of the construction permit, information on the operational water flow rate to the FGD system to be used for monitoring the flow rate of water to the FGD system, as required under condition I.A.14.b.(7). [s. 285.65(10), Wis. Stats.]

(3) Compliance with the fuel oil sulfur requirements of I.A.14.b.(6) shall be determined using periodic sampling and analysis using methods and procedures specified under condition I.A.13.c.(4). [s. NR 439.06(2)(c), Wis. Adm. Code]

(4) The sulfur content of a liquid fossil fuel sample shall be determined according to ASTM D129-95, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), ASTM D1552-95, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), or ASTM D4294-98, Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectroscopy. [s. NR 439.08(2)(b), Wis. Adm. Code]

(5) During operation, the facility will calculate or continuously monitor and record the unit heat input and the following operating parameters on an hourly basis.
a. Furnace outlet temperature, ^{o}F
b. Secondary Air Flow
c. Primary Air Flow
d. Fuel Flow Rate
e. Residence Time (by calculation only)
[s. 285.65(10), Wis. Stats.]

(6) The permittee shall install, calibrate, maintain and operate instrumentation to monitor the parameters identified by condition I.A.14.c.(5)a.-d. [s. 285.65(3) and (10), Wis. Stats.]

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[11] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18– Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 15. Hydrogen Chloride

a. Limitations: 16.2 pounds per hour, based upon a 24-hour average (MACT), regulated under sec. 112 of the Clean Air Act. [s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation. [s. NR 439.07, Wis. Adm. Code]

(3) Hydrogen Chloride emissions shall be controlled by the use of wet flue gas desulfurization (FGDS) Systems to meet the MACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(3) The boiler may only be fired on coal and/or ash fuel blend, except for periods of start-up and load stabilization when natural gas or fuel oil may also be utilized as a fuel. [s. NR 405.08(2), Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(4) The permittee shall perform the compliance emission tests required under condition I.A.15.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. NR 439.075(3)(b) Wis. Adm. Code]

(5) The absorber recirculation (AR) slurry flow rate of water to the FGD system shall be periodically monitored and maintained within the range specified under condition I.A.15.c.(2). [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Hydrogen Chloride Emissions: Whenever compliance emission testing is required, US EPA Method 26A shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]

(2) The permittee shall provide to the department, at least 4 months prior to the expiration of the construction permit, information on the operational absorber recirculation (AR) slurry flow rate to the FGD system to be used for monitoring the absorber recirculation (AR) slurry flow rate to the FGD system, as required under condition I.A.15.b.(3), and shall incorporate this information into the Malfunction Prevention and Abatement Plan. [s. 285.65(10), Wis. Stats.]

(3) Instrumentation to monitor the absorber recirulation (AR) slurry flow rate to the wet flue gas desulfurization (FGD) system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

B. S20, B20 – SCPC Auxiliary Boiler

Pollutant: 1. Particulate Matter Emissions

a. Limitations: (1) The emissions may not exceed 0.007 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.05 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation when firing distillate fuel oil.[12] [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall determine the hourly emissions using fuel consumption records and emissions factor determined by stack testing. [s. 285.65(3), Wis. Stats.]

(3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 280.0 feet above ground evel. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 5.0 eet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(4) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(6) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.1.a. (4). [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60, Appendix A, Reference Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall keep records on the heat input used as required in condition I.B.1.b.(6). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) The permittee shall record information on the maintenance required in condition I.B.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Note 1: The boiler is subject to NSPS requirements under s. NR 440.205, Wis. Adm. Code for particulate matter. The only New Source Performance Standards (NSPS) standard that will be applicable to the boiler for PM is in the form of an opacity standard when fuel oil is fired per 40 CFR Part 60.43b(f) and s. NR 440.205(4) (f), Wis. Adm. Code.

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[12] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

B. S20, B20 – SCPC Auxiliary Boiler

Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM_{10})

Limitations: (1) The emissions may not exceed 0.007 pound per million Btu when firing natural gas. (BACT).; (2) The emissions may not exceed 0.05 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[13] [s. NR 439.07, Wis. Adm. Code] (1) The permittee shall determine the hourly emissions using fuel consumption records and emissions factor determined by stack testing. [s. 285.65(3), Wis. Stats.] (3) <u>Stack Parameters:</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 280 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 5.0 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire natural gas and/or fuel having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (6) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.2.a. (4). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall keep records on the heat input used as required in condition I.B.2.b.(6). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall record information on the maintenance required in condition I.B.2.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

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[13] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

B. S20, B20 – SCPC Auxiliary Boiler

Pollutant: 3. Sulfur Dioxide

a. Limitations: (1) The emissions may not exceed 0.0024 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.0032 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption records, fuel sulfur content and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Sulfur Dioxide Emissions: Whenever compliance emission testing is required, US EPA Method 6, 6A or 6C shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(2), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.B.3.b.(8). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.B.3.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Note 1: The sulfur dioxide New Source Performance Standard (NSPS) in Subpart Db and s. NR 440.205(3), Wis. Adm. Code will be applicable to the boiler only when fuel oil is fired. Based on vendor specification for fuel oil and the proposed BACT limits, the sulfur percentage of the fuel will not exceed 0.05% by weight. Thus it meets the definition for "very low sulfur fuel oil" given in 40 CFR 60.41 and s. NR 440.205(2)(zj), Wis. Adm. Code. Affected sources combusting only very low sulfur fuel oil are not subject to percent reduction requirements required under 40 CFR 60.42(a) per s. NR 440.205(3)(j), Wis. Adm. Code. Also, facilities that combust very low sulfur fuel oil are not required to conduct performance testing or install and operate continuous monitors for sulfur dioxide and if fuel receipts are maintained.

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 3. Sulfur Dioxide (continued)	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(4) A representative sample shall be taken from each fuel lot of fuel oil received. The sample shall be analyzed by the permittee for the sulfur content by weight using procedures outline in s. NR 439.08(2), Wis. Adm. Code and the analysis shall be retained by the permittee for a period of at least five years. [s. 285.65(3), Wis. Stats.] (5) The Department will accept, in lieu of an analysis on each fuel lot under (4) above, an analysis of a representative sample of the fuel lot of distillate fuel oil from which the fuel lot was taken. [s. 285.65(3), Wis. Stats.] (6) The permittee shall retain copies of its distillate fuel oil supplier's fuel sulfur and heat content analyses at the facility for each fuel lot of distillate fuel oil received pursuant to 40 CFR 60.334 for a period of five years. [s. NR 439.04(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall further obtain certification from the fuel supplier that the applicable methods in s. NR 439.08(2), Wis. Adm. Code, were followed, if applicable, by the supplier in the preparation of said sulfur and heat content analyses. The fuel lot's quantity of fuel oil shall be included with the copies of these analyses. [s. 285.65(3), Wis. Stats.] (8) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.3.a. (4). [s. 285.65(3), Wis. Stats.]	(5) The permittee shall keep records required under condition I.B.3.b.(4) – (7). [s. NR 439.04(1)(d), Wis. Adm. Code] (6) The permittee shall obtain and maintain fuel receipts from the fuel supplier which certify that the fuel oil meets the definition of distillate oil as defined in s. NR 440.205(2)(h), Wis. Adm. Code, if the permittee combust very low sulfur fuel oil as defined under s. NR 440.205(2)(zj), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. NR 440.205(3)(j)2., Wis. Adm. Code, s. 285.65(7), Wis. Stats.] (7) The permittee shall submit quarterly reports to the Department certifying that only very low sulfur fuel oil meeting the definition was combusted in the affected facility during the preceding quarter. [s. 285.65(7), Wis. Stats., s. NR 440.205(10)(r), Wis. Adm. Code.]

B. S20, B20 – SCPC Auxiliary Boiler

Pollutant: 4. Oxides of Nitrogen

a. Limitations: (1) The emissions may not exceed 0.036 pound per million Btu when firing natural gas based on a 30-day rolling average. (BACT); (2) The emissions may not exceed 0.09 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight oil based on a 30-day rolling average. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months.[s. NR 405.08(2), Wis. Adm. Code, s, NR 428.04(2)(a)2. and 3., s. NR 428.04(2)(a)2. and 3., s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption record and vendors or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s, 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.4.a. (4). [s. 285.65(3), Wis. Stats.]

(5) The permittee shall determine compliance with the emission limits in I.B.4.a.(2) by conducting performance test as required under s. NR 440.08, Wis. Adm. Code using one the continuous systems for monitoring nitrogen oxides under s. NR 440.205(9)(g), Wis. Adm. Code as follows:

(a) Comply with the provisions of s. NR 440.205(9)(b), (c), (d), (e) 2., (e) 3., and (f), or

(b) Monitor steam generating unit operating conditions and predict nitrogen oxides emission rates as specified in a plan submitted pursuant to s. NR 440.205(10)(c), Wis. Adm. Code.

(c) Submit a plan as required under s. NR 440.205(10)(c) to the Department for approval within 360 days of the initial startup of the facility. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Nitrogen Oxide Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60, US EPA Method 7 or an alternate method approved in writing by the Department shall be used to demonstrate compliance.
[s. NR 439.06(6), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.B.4.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.B.4.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

(5) The permittee shall maintain records of the information required under s. NR 440.205(1)(g), Wis. Adm. Code. A copy of the requirements attached with this permit. [s. 285.65(3), Wis. Stats.]

(6) The permittee shall submit quarterly reports containing the information recorded in (5) above to the Department for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. [s. 285.65(3), Wis. Stats., s. NR 440.205(10)(l), Wis. Adm. Code]

Note 1: The boiler will have high heat release rate and therefore subject to New Source Performance Standards (NSPS) emission limit of 0.20 pound per million Btu on a 30 day rolling average per s. NR 440.205(5)(a)1.b., Wis. Adm. Code for NOx. The proposed BACT emission limit for NOx is more restrictive then the NSPS limit for NOx.

Note 2: The boiler is subject to s. NR 428.04(2)(a)2. and 3., Wis. Adm. Code and is 0.05 pounds per million Btu of heat input when firing natural gas and 0.09 pounds per million Btu of heat input when firing fuel oil for NOx. The BACT limit for NOx is more restrictive or equal to the NOx limit established under s. NR 428,04, Wis. Adm. Code, thus the boiler is expected to meet the limits for NOx emission limits under s. NR 428.04, Wis. Adm. Code.

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 4. Oxides of Nitrogen [CONTINUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
	(8) The permittee shall comply with the general and specific monitoring requirements under s. NR 428.04(3)(a) and (b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (9) The permittee shall comply with all the recordkeeping and reporting requirements under s. NR 428.04(4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (10) The permit shall comply with all the requirements for monitoring, installation, certification, data accounting, compliance dates and reporting data prior to initial certification as required under s. NR 428.07(1)(b), Wis. Adm. Code, s. NR 428.07(2)(b)2, Wis. Adm. Code, s, NR 428.07(3), Wis. Adm. Code. [s. 285.65(3), Wis. Stats.] (11) The permittee shall monitor NOx and heat input per s. NR 428.08(1)(c), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (12) The permittee shall submit quarterly reports per s. NR 428.09(1), (3) and (4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(9), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

B. S20, B20 – SCPC Auxiliary Boiler

Pollutant: 5. Carbon Monoxide

a. Limitations: (1) The emissions may not exceed 0.075 pound per million Btu when firing natural gas based on a 30-day rolling average. (BACT); (2) The emissions may not exceed 0.075 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight based on a 30-day rolling average. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 factor or vendor provided emissions factor [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and /or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.5.a. (4). [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Carbon Monoxide Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, US EPA Method 10, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(4), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.B.5.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.B.5.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

B. S20, B20 – SCPC Auxiliary Boiler

Pollutant: 6. Volatile Organic Compounds (VOC)

a. Limitations: (1) The emissions may not exceed 0.0060 pound per million Btu when firing natural gas based on a 30-day rolling average. (LAER); (2) The emissions may not exceed 0.0050 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight based on a 30-day rolling average. (LAER); (3) The use of good combustion practices. (LAER); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 408.04, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor or vendor provided emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet LAER emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.6.a. (4). [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) <u>Reference Test Method for VOC Emissions:</u> Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, US EPA Method 25 or 18, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(3), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.B.6.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.B.6.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

B. S20, B20 – SCPC Auxiliary Boiler

Pollutant: 7. Lead Emissions

a. Limitations: (1) The emissions may not exceed 0.000000024 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.000009 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.7.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Lead Emissions: Whenever compliance emission testing is required, US EPA Method 12 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.B.7.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.B.7.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

B. S20, B20 – SCPC Auxiliary Boiler

Pollutant: 8. Mercury Emissions

a. Limitations: (1) The emissions may not exceed 0.00000026 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.000003 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.8.a. (4). [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Mercury Emissions: Whenever compliance emission testing is required, US EPA Method 29 or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.B.8.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.B.8.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

B. S20, B20 – SCPC Auxiliary Boiler

Pollutant: 9. Emissions of Fluorides

a. Limitations: (1) The emissions may not exceed 0.027 pound per million Btu when firing natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (2) The use of good combustion practices. (BACT); (3) The total heat input may not exceed 498,000 mmBtu on a 12-month rolling average, of which no more than 122,500 mmBtu may be from the combustion of fuel oil on a 12-month rolling average. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.9.a. (3). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Emissions of Fluorides:</u> Whenever compliance emission testing is required, US EPA Method 13B shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.B.9.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.B.9.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Pollutant: 10. Visible Emissions

a. Limitations: 20% opacity or number 1 on the Ringlemann chart. [s. NR 431.05, Wis. Adm. Code, s. NR 440.205(4)(f), Wis. Adm. Code] See Note 1

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (2) The permittee shall conduct an initial test as required under s. NR 440.08, Wis. Adm. Code using the procedures and reference method in 40 CFR part 60, Appendix A, which is incorporated by reference in s. NR 440.17, Wis. Adm. Code. [s. NR 440.205(7)(d), Wis. Adm. Code]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

Note 1: Any gases emitted from the stack when the unit is fired with fuel oil shall not have an opacity greater than 20% (6 minutes average). The exception is one 6-minute period per hour when the opacity not exceeding 27%. The opacity standard does not apply during periods of start up and shut down or malfunction per s. NR 440.025(4)(f), Wis. Adm. Code.

<table>
<tr><td colspan="2">B. S20, B20 – SCPC Auxiliary Boiler</td></tr>
<tr><td colspan="2">Pollutant: 11. Hazardous air pollutants (inorganic solid HAPs, Inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.</td></tr>
<tr><td colspan="2">a. Limitations: (1) The permittee shall use natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight and comply with the PM/PM10 limits to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall us natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight to comply with the case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with and meet the VOC LAER emission limits to comply with case by case MACT for organic HAPs and (4) The total heat input may not exceed 498,000 mmBtu on a 12-month rolling average, of which no more than 122,500 mmBtu may be from the combustion of fuel oil on a 12-month rolling average. [s. 285.65(13), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and/or 0.003% by weight low sulfur fuel oil. This condition is established to meet MACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.11.a. (4). [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs:</u> Whenever compliance emission testing is required a method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.B.11.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.B.11.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]</td></tr>
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B. S20, B20 – SCPC Auxiliary Boiler

Pollutant: 12. Sulfuric Acid Mist

a. Limitations: (1) The emissions may not exceed 0.00024 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.00064 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu on a 12-month rolling average, of which no more than 122,500 mmBtu may be from the combustion of fuel oil on a 12-month rolling average. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption records, and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (3) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.12.a. (4). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Sulfur Acid Mist Emissions:</u> Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] 2) The permittee shall keep records on the heat input used as required in condition I.B.12.b.(3). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall keep records required under condition I.B.3.b.(4) – (7) to demonstrate compliance with the sulfur content in the fuel. [s. NR 439.04(1)(d), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 1. Particulate Matter Emissions

a. Limitations: (1) The emissions may not exceed 1.94 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive month period.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight . (BACT); (4) The use of good combustion practices (BACT).; (5) The emissions unit may be operated only during the hours from 9:00 am to 1:00 PM. This condition is established to protect the ambient air quality standards. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation when firing natural gas and fuel oil.[14] [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall determine the hourly emissions using operating parameters and certified test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.]

(3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 18 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 2.12 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(4) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60, Appendix A and US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code)]

(3) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.1.a.(2). [s. 285.65(10), Wis. Stats., 285.65(3), Wis. Stats.]

(4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) The permittee shall record information on the maintenance required in condition I.C.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

(6) The permittee shall record the start and end times of the diesel generator operation to demonstrate compliance with condition I.C.1.a.(5). [s. 285.65(3), Wis. Stats.]

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[14] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM_{10})

a. Limitations: (1) The emissions may not exceed 1.94 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) (5) The emissions unit may be operated only during the hours from 9:00 am to 1:00 PM. This condition is established to protect the ambient air quality standards. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.15 [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall determine the hourly emissions using operating parameters and certified test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.]

(3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 18 feet above ground evel. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 2.12 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(4) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.1.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) The permittee shall record information on the maintenance required in condition I.C.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

(6) The permittee shall record the start and end times of the diesel generator operation to demonstrate compliance with condition I.C.2.a.(5). [s. 285.65(3), Wis. Stats.]

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15 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 3. Sulfur Dioxide

a. Limitations: (1) The emissions may not exceed 0.05 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight . (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption records, fuel sulfur content and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire fuel oil having a sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Sulfur Dioxide Emissions: Whenever compliance emission testing is required, US EPA Method 6, 6A or 6C shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(2), Wis. Adm. Code]

(2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.3.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.C.3.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 3. Sulfur Dioxide (continued)

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(4) A representative sample shall be taken from each fuel lot of fuel oil received. The sample shall be analyzed by the permittee for the sulfur content by weight using procedures outline in s. NR 439.08(2), Wis. Adm. Code and the analysis shall be retained by the permittee for a period of at least five years. [s. 285.65(3), Wis. Stats.] (5) The Department will accept, in lieu of an analysis on each fuel lot under (4) above, an analysis of a representative sample of the fuel lot of distillate fuel oil from which the fuel lot was taken. [s. 285.65(3), Wis. Stats.] (6) The permittee shall retain copies of its distillate fuel oil supplier's fuel sulfur and heat content analyses at the facility for each fuel lot of distillate fuel oil received pursuant to 40 CFR 60.334 for a period of five years. [s. NR 439.04(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall further obtain certification from the fuel supplier that the applicable methods in s. NR 439.08(2), Wis. Adm. Code, were followed, if applicable, by the supplier in the preparation of said sulfur and heat content analyses. The fuel lot's quantity of fuel oil shall be included with the copies of these analyses. [s. 285.65(3), Wis. Stats.]	(5) The permittee shall keep records required under condition I.C.3.b.(4) – (7). [s. NR 439.04(1)(d), Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 4. Oxides of Nitrogen (NOx)

a. Limitations: (1) The emissions may not exceed 6.9 g/bhp-hr and 33.4 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. NR 428.04(2)(h), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using operating parameters and certified emission test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Nitrogen Oxide Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60, US EPA Method 7 or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(6), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.4.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.4.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (5) The permittee shall comply with the general and specific monitoring requirements under s. NR 428.04(3)(a) and (b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (6) The permittee shall comply with all the recordkeeping and reporting requirements under s. NR 428.04(4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall comply with all the requirements for monitoring, installation, certification, data accounting, compliance dates and reporting data prior to initial certification as required under s. NR 428.07(1)(b), Wis. Adm. Code, s. NR 428.07(2)(b)2, Wis. Adm. Code, s. NR 428.07(3), Wis. Adm. Code. [s. 285.65(3), Wis. Stats.] (8) The permittee shall submit quarterly reports per s. NR 428.09(2), (3) and (4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(9), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

Note 1: The diesel generator is subject to s. NR 428.04(2)(h), Wis. Adm. Code and is 6.9 grams per brake horsepower when firing natural gas and firing fuel oil for NOx. The BACT limit for NOx is more restrictive then the NOx limit under s. NR 428,04, Wis. Adm. Code, thus the diesel generator is expected to meet the NOx limits under s. NR 428.04, Wis. Adm. Code.

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 5. Carbon Monoxide

a. Limitations: (1) The emissions may not exceed 41.19 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using operating parameters and certified emission test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Carbon Monoxide Emissions:</u> Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, US EPA Method 10, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(4), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.5.a.(2). [s. 285.65(10), Wis. Stats., 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.5.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, -Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 6. Volatile Organic Compounds (VOC)

b. Limitations: (1) The emissions may not exceed 4.8 pounds per hour. (LAER); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (LAER); (4) The use of good combustion practices. (LAER) [s. NR 408.04, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using operating parameters and certified emission test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for VOC Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, US EPA Method 25 or 18, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(3), Wis. Adm. Code]
(2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet LAER emission limit. [s. NR 405.08(2), Wis. Adm. Code]	(2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.6.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]
(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.6.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 7. Lead Emissions

a. Limitations: (1) The emissions may not exceed 0.000114 pound per hour . (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight.. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Lead Emissions: Whenever compliance emission testing is required, US EPA Method 12 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(5), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.7.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.7.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 8. Mercury Emissions

a. Limitations: (1) The emissions may not exceed 0.00000682 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Mercury Emissions: Whenever compliance emission testing is required, US EPA Method 29 or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.8.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.8.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

C. S62, B62, – Emergency Diesel Generator 1; S63, B63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 9. Emissions of Fluorides

a. Limitations: (1) The emissions may not exceed 0.00088 pound per million Btu Heat Input . (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Emissions of Fluorides:</u> Whenever compliance emission testing is required, US EPA Method 13B shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.9.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.9.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Pollutant: 10. Visible Emissions

a. Limitations: 20% opacity or number 1 on the Ringlemann chart. [s. NR 431.05, Wis. Adm. Code]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 11. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.

a. Limitations: (1) The permittee shall use fuel oil having a maximum sulfur content of 0.003% by weight and comply with the PM/PM10 limits to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall use fuel oil having a maximum sulfur content of 0.003% by weight to comply with the case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with and meet the VOC emission limits to comply with case by case MACT for organic HAPs and (4) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (5) The use of good combustion practices. (BACT) [s. 285.65 (13), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet MACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs: Whenever compliance emission testing is required method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.11.a.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.11.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.

Pollutant: 12. Sulfuric Acid Mist

a. **Limitations:** (1) The emissions may not exceed 0.005 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. [s. NR 405.08(2), Wis. Adm. Code; s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. **Compliance Demonstration:**	c. **Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption records, and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Sulfur Acid Mist Emissions: Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall keep an operating log, which records the monthly hours of operation, to demonstrate compliance with condition I.C.12.a.(2). [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) The permittee shall retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. 285.65(3), Wis. Stats.] (4) The permittee shall keep records required under condition I.C.3.b.(4) – (7) to demonstrate compliance with the sulfur content in the fuel. [s. NR 439.04(1)(d), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

<table>
<tr><th colspan="2">D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.</th></tr>
<tr><td colspan="2">Pollutant: 1. Particulate Matter Emissions</td></tr>
<tr><td colspan="2">a. Limitations: (1) The emissions may not exceed 0.21 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive month period.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight . (BACT); (4) The use of good combustion practices. (BACT); (5) The emissions unit may be operated only during the hours from 9:00 am to 1:00 PM. This condition is established to protect the ambient air quality standards. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.16 [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall determine the hourly emissions using fuel consumption and vendor provided emission factors. [s. 285.65(3), Wis. Stats.]

(3) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The height of stack S64 shall be at least 32 feet above ground level and the height of the stack S175 shall be at least 32 feet and the height of stack S176 shall be at least 12.0 feet. [s. 285.65(3), Wis. Stats, s. NR 406.10, Wis. Adm. Code]

(b) The inside diameter at the outlet of the stack S64 may not exceed 0.7 feet and the inside diameter at the outlet of the stack S175 may not exceed 0.7 feet and the inside diameter at the outlet of the stack S176 may not exceed 0.7 feet. [s. 285.65(3), Wis. Stats, s. NR 406.10, Wis. Adm. Code]

(4) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, test procedures in 40 CFR 60 and US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.1.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) The permittee shall record information on the maintenance required in condition I.D.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

(6) The permittee shall record the start and end times of the diesel generator operation to demonstrate compliance with condition I.D.1.a.(5). [s. 285.65(3), Wis. Stats.]</td></tr>
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[16] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.

Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM_{10})

a. **Limitations:** (1) The emissions may not exceed 0.21 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT); (5) The emissions unit may be operated only during the hours from 9:00 am to 1:00 pm. This condition is established to protect the ambient air quality standards. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.17 [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall determine the hourly emissions using operating parameters and certified test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.]

(3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The height of stack S64 shall be at least 32 feet above ground level and the height of the stack S175 shall be at least 32 feet and the height of stack S176 shall be at least 12.0 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The inside diameter at the outlet of the stack S64 may not exceed 0.7 feet and the inside diameter at the outlet of the stack S175 may not exceed 0.7 feet and the inside diameter at the outlet of the stack S176 may not exceed 0.7 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(4) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.2.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) The permittee shall record information on the maintenance required in condition I.D.2.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

(6) The permittee shall record the start and end times of the diesel generator operation to demonstrate compliance with condition I.D.2.a.(5). [s. 285.65(3), Wis. Stats.]

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[17] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.

Pollutant: 3. Sulfur Dioxide

a. Limitations: (1) The emissions may not exceed 0. 01 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records, fuel sulfur content and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Sulfur Dioxide Emissions: Whenever compliance emission testing is required, US EPA Method 6, 6A or 6C shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(2), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.3.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.3.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump. [CONTINUED]

Pollutant: 3. Sulfur Dioxide (continued)

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(4) A representative sample shall be taken from each fuel lot of fuel oil received. The sample shall be analyzed by the permittee for the sulfur content by weight using procedures outline in s. NR 439.08(2), Wis. Adm. Code and the analysis shall be retained by the permittee for a period of at least five years. [s. 285.65(3), Wis. Stats.] (5) The Department will accept, in lieu of an analysis on each fuel lot under (4) above, an analysis of a representative sample of the fuel lot of distillate fuel oil from which the fuel lot was taken. [s. 285.65(3), Wis. Stats.] (6) The permittee shall retain copies of its distillate fuel oil supplier's fuel sulfur and heat content analyses at the facility for each fuel lot of distillate fuel oil received pursuant to 40 CFR 60.334 for a period of five years. [s. NR 439.04(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall further obtain certification from the fuel supplier that the applicable methods in s. NR 439.08(2), Wis. Adm. Code, were followed, if applicable, by the supplier in the preparation of said sulfur and heat content analyses. The fuel lot's quantity of fuel oil shall be included with the copies of these analyses. [s. 285.65(3), Wis. Stats.]	(5) The permittee shall keep records required under condition I.D.3.b.(4) – (7). [s. NR 439.04(1)(d), Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.

Pollutant: 4. Oxides of Nitrogen

a. Limitations: (1) The emissions may not exceed 14.0 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and vendor provided emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Nitrogen Oxide Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60, US EPA Method 7 or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(6), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.4.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.4.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.

Pollutant: 5. Carbon Monoxide

a. Limitations: (1) The emissions may not exceed 3.36 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption records and vendor provided emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Carbon Monoxide Emissions: Whenever compliance emission testing is required, US EPA Method 10, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(4), Wis. Adm. Code]

(2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.5.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.D.5.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump The following emission limits apply to each fire pump.	
Pollutant: 6. Volatile Organic Compounds (VOC)	
a. Limitations: (1) The emissions may not exceed 0.31 pounds per hour. (LAER); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (LAER); (4) The use of good combustion practices. (LAER) [s. NR 408.04, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and vendor provided emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet LAER emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for VOC Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, Appendix A, US EPA Method 25 or 18, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.6.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.6.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.

Pollutant: 7. Lead Emissions

a. Limitations: (1) The emissions may not exceed 0.0000274 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive month period.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight . (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Lead Emissions: Whenever compliance emission testing is required, US EPA Method 12 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(5), Wis. Adm. Code]

(2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.7.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.D.7.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.

Pollutant: 8. Mercury Emissions

a. Limitations: (1) The emissions may not exceed 0.00000164 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Mercury Emissions: Whenever compliance emission testing is required, US EPA Method 29 or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.8.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.8.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.

Pollutant: 9. Emissions of Fluorides

Limitations: (1) The emissions may not exceed 0.00000376 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Emissions of Fluorides: Whenever compliance emission testing is required, US EPA Method 13B shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.9.a.(2). [s. 285.65(10), Wis. Stats., 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.9.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code

Pollutant: 10. Visible Emissions

a. Limitations: 20% opacity or number 1 on the Ringlemann chart. [s. NR 431.05, Wis. Adm. Code]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.

Pollutant: 11. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.

a. Limitations: (1) The permittee shall use fuel oil having a maximum sulfur content of 0.003% sulfur by weight and comply with the PM/PM10 limits to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall us fuel oil having a maximum sulfur content of 0.003% by weight to comply with the case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with and meet the VOC emission limits to comply with case by case MACT for organic HAPs and (4) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (5) The use of good combustion practices. (BACT) [s. NR 445.04(3)(a), Wis. Adm. Code]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet MACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs: Whenever compliance emission testing is required a method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.11.a.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.11.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

<table>
<tr><td colspan="2">D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.</td></tr>
<tr><td colspan="2">Pollutant: 12. Sulfuric Acid Mist</td></tr>
<tr><td colspan="2">a. Limitations: (1) The emissions may not exceed 0.001pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]
(2) The permittee shall determine the hourly emissions using fuel consumption records, and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Sulfur Acid Mist Emissions:</u> Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]
(2) The permittee shall keep an operating log, which records the monthly hours of operation, to demonstrate compliance with condition I.D.12.a.(2). [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]
(3) The permittee shall retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. 285.65(3), Wis. Stats.]
(4) The permittee shall keep records required under condition I.D.3.b.(4) – (7) to demonstrate compliance with the sulfur content in the fuel. [s. NR 439.04(1)(d), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]</td></tr>
</table>

E. S23, P23 – Crusher House Dust Collector No. 1; S24, P24 – Crusher House Dust Collector No. 2
The following emission limits apply to each crusher house duct collector.

Pollutant: 1. Particulate Matter Emissions

a. **Limitations:** 0.004 grains per dry standard cubic foot of exhaust gas and 1.307 pounds per hour. (BACT) [s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests for one of the crusher house dust collector 1 or 2 shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[18] [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 160 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 3.73 Feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.E.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[18] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

E. S23, P23 – Crusher House Dust Collector No. 1; S24, P24 – Crusher House Dust Collector No. 2
The following emission limits apply to each crusher house duct collector.

Pollutant: 2. Visible Emissions

a. Limitations: 10% opacity. [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 440.42(3)(c), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.E.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

Note 1: The coal handling/storage operations are subject to s. NR 440.42(3)(c), Wis. Adm. Code (New Source Performance Standards, NSPS requirements) for visible emissions. For these operation, s. NR 440.42(3)(c), Wis. Adm. Code prohibits visible emissions of 20 percent opacity or greater for any coal processes and conveying equipment, coal storage system, or coal transfer and loading system. The BACT limit for opacity is more restrictive then NSPS limits for opacity thus the crusher house operation is expected to be in compliance with the NSPS emission limits for opacity.

F. S27, P27- Fly Ash Silo Filter Vent 1; S65, P65 – Fly Ash Silo Filter Vent 2
The following emission limits apply to each of the fly ash silo filter vent.

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.02 grains per dry standard cubic foot of exhaust gas and 0.394 pound per hour. (BACT) [s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) The permittee shall determine hourly emissions using operating parameters and OEM emission factors. [s. 285.65(3), Wis. Stats.]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 120 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 3.4 Feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a bin vent filter system to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The bin vent filter system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The permittee shall develop and follow a Malfunction Prevention and Abatement Plan for the bin vent filter system. The plan shall identify the specific measures that will be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific measures could include: filter inspection schedule, filter replacement criteria, etc. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(6) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(7) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters and bin vent filter. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the bin vent filter system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

F. S27, P27- Fly Ash Silo Filter Vent 1; S65, P65 – Fly Ash Silo Filter Vent 2
The following emission limits apply to each of the fly ash silo filter vent.

Pollutant: 2. Visible Emissions

a. Limitations: 10% opacity. [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The bin vent filter system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The compliance method in I.F.1.b. shall be used to demonstrate compliance with the visible emission limits. [s. NR 407.09(4)(a)1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the bin vent filter system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

G. S28, P28 - Existing Junction House 7/8 Dust Collector

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.01 grains per dry standard cubic foot of exhaust gas and 2.331 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.19 [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 175 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 3.1 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.G.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[19] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

G. S28, P28 - Existing Junction House 7/8 Dust Collector

Pollutant: 2. Visible Emissions

a. Limitations: 10% opacity. [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]
(2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.G.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]	(2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]
(3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]	(3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]
(4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

H. S47, P47 – Limestone Prep Building Dust Collector

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 0.480 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. NR 440.688(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[20] [s. NR 440.688(6)(b), Wis. Adm. Code, s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 60 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 2.3 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.H.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 440.688(6)(b), Wis. Adm. Code, s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

Note 1: The limestone prep operation is subject to New Source Performance Standards (NSPS) for particulate matter under s. NR 440.688(3), Wis. Adm. Code and the limit is 0.022 gr/acf. The BACT limit for particulate matter is more restrictive than NSPS limit for particulate matter thus the limestone prep operation is expected to meet the NSPS emission limit for particulate matter.

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[20] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

H. S47, P47 – Limestone Prep Building Dust Collector

Pollutant: 2. Visible Emissions

a. Limitations: 7% opacity. [s. NR431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. NR 440.688(3)(a), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]
(2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.H.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]	(2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]
(3) The permittee shall determine compliance with the visible emission limits using EPA Approved Method 9. [s. NR 440.688(6)(b)2., Wis. Adm. Code; [s. 285.65(3), Wis. Stats.]	(3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]
(4) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]	(4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]
(5) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(5) The permittee shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the visible emission limits in I.H.2.a. Including reports of opacity observations made using Method 9. [s. 285.65(3), Wis. Stats.]

Note 1: The limestone prep operation is subject to New Source Performance Standards (NSPS) to visible emissions limit under s. NR 440.688(3), Wis. Adm. Code and the limit is 7% opacity.

I S48, P48 - XFr Tower No. 3 And Tripper Room Unit 1 Dust Collector

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 1.759 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[21] [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 280 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 4.33 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.I.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[21] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

I S48, P48 - XFr Tower No. 3 And Tripper Room Unit 1 Dust Collector	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.I.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

J. S49, P49 - Tripper Room Dust Collector Unit 2

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 1.182 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.22 [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 240 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 3.6 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.J.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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22 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

J. S49, P49 – Tripper Room Dust Collector Unit 2

Pollutant: 2. Visible Emissions

a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]
(2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.J.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]	(2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]
(3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]	(3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]
(4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

K. S58, P58 - XFr Tower House #5 Dust Collector

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 0.567 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[23] [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 196 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 2.5 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.K.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[23] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

K. S58, P58 – XFr Tower House #5 Dust Collector

Pollutant: 2. Visible Emissions

a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.K.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

L. S59A, P59A - IGCC Coal Silos Dust Collector a; S59B, P59B – IGCC Coal Silos Dust Collector b
The following emission limits apply to each IGCC coal silos dust collector.

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 1.371 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests on any one IGCC coal silos dust collector or b shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[24] [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 130 feet above ground level. [s. 285.65(3), Wis. Stats, s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 3.8 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determined during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.L.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[24] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

L. S59A, P59A - IGCC Coal Silos Dust Collector a; S59B, P59B – IGCC Coal Silos Dust Collector b
The following emission limits apply to each IGCC coal silos dust collector.

Pollutant: 2. Visible Emissions

a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.L.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

Note 1: The coal handling/storage operations are subject to s. NR 440.42(3)(c), Wis. Adm. Code (New Source Performance Standards, NSPS requirements) visible emissions. For these operation, s. NR 440.42(3)(c), Wis. Adm. Code prohibits visible emissions of 20 percent opacity or greater for any coal processes and conveying equipment, coal storage system, or coal transfer and loading system. The BACT limit for opacity is more restrictive then NSPS limits for opacity thus the coal handling/storage operations is expected to be in compliance with the NSPS visible emission limits.

M. S66, P66 – XFr Tower No. 4 Dust Collector

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 0.944 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[25] [s. NR 439.07, Wis. Adm. Code] (2) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 25 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 3.2 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.M.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[25] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

M. S66, P66 - Transfer Tower No. 4 Dust Collector

Pollutant: 2. Visible Emissions

a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]
(2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.M.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]	(2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]
(3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]	(3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]
(4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

N. S76, P76 - Coal Car Dumper Dust Collector No. 1

Pollutant: 1. Particulate Matter Emissions

a. **Limitations:** 0.004 grains per dry standard cubic foot of exhaust gas and 5.531 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.26 [s. NR 439.07, Wis. Adm. Code] (2) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 60 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 7.68 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10 and s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.B.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) Reference <u>Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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26 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

N. S76, P76 - Coal Car Dumper Dust Collector No. 1	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s, NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.N.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

O. S93A – S93T, P93 – Active Coal Storage and handling Operations Building Ventilators a-t
The limits apply to each stack associated with the coal storage building ventilators.

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.024 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) The permittee shall utilize a building to control emissions from coal stackout, storage and reclaim operations, a stackout conveyor – with telescopic chute or travelling stacking conveyor with short drop, and coal reclaim system with short chute drop and loading table to minimize emissions and to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits.[s. NR 415.04(1)(b), Wis. Adm. Code]

(3) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]

(4) The permittee shall ensure that the Trained Person designated:
  (a) Has training to evaluate compliance with Wisconsin air quality regulations, or
  (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or
  (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit.
[s. 285.65(3), Wis. Stats.]

(5) The permittee shall determine the hourly emissions using the hourly throughput and AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 5 and Method 202 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.O.1.b.(3) shall sign and date the records required in I.O.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by condition I.O.1.b.(4)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

O. S93A – S93T, P93 – Active Coal Storage and Handling Operations Building Ventilators a-t **The limits apply to each stack associated with the coal storage building ventilators.**	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. (Best Available Control Technology, BACT) [s. NR 431.05, Wis. Adm. Code, s. NR 405.08(2), Wis. Adm. Code, s. NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions.

P. S104, P104 – Gypsum Storage and Handling Operations Building Exhaust Fan No. 1; S105, P105 – Exhaust Fan No. 2; S106, P106 – Exhaust Fan No. 3

The following emission limits apply to each gypsum building exhaust fan.

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.377 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) The permittee shall utilize a building to control emissions from gypsum stackout, storage and reclaim operations, and a reversible shuttle conveyor to distribute gypsum along the pile crest with short drop to minimize emissions and to minimize emissions and to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits.[s. NR 415.04(1)(b), Wis. Adm. Code]

(3) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]

(4) The permittee shall ensure that the Trained Person designated:
  (a) Has training to evaluate compliance with Wisconsin air quality regulations, or
  (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or
  (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit.
[s. 285.65(3), Wis. Stats.]

(5) The permittee shall determine the hourly emissions using hourly throughput and AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 5 and Method 202 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.P.1.b.(3) shall sign and date the records required in I.P.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by condition I.P.1.b.(4)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

P. S104, P104 – Gypsum Storage and Handling Operations Building Exhaust Fan No. 1; S105, P105 – Exhaust Fan No. 2; S106, P106 – Building Exhaust Fan No. 3
The following emission limits apply to each gypsum building exhaust fan.

Pollutant: 2. Visible Emissions

a. Limitations: 10% opacity. (Best Available Control Technology, BACT) [s. NR 431.05, Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions.

Q. S109, P109- Fuel Ash Building Exhaust Fan

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.240 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall utilize a building to control emissions from fuel ash stackout, storage, and reclaim operations, stackout drop from telescopic chute and reclaim fuel ash into hopper via front end loader to minimize emissions and to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (2) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits.[s. NR 415.04(1)(b), Wis. Adm. Code] (3) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (4) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.] (5) The permittee shall determine the hourly emissions using throughput and AP-42 emission factors. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 5 and Method 202 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I.Q.1.b.(3) shall sign and date the records required in I.Q.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by condition I.Q.1.b.(4) training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Q. S109, P109 – Ash Reburn Building Exhaust Fan	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. (Best Available Control Technology, BACT) [s. NR 431.05, Wis. Adm. Code, s. NR 405.08(2), Wis. Adm. Code, s. NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions.

R. S114, P31- OCPP Fly Ash Storage Building Dust Collector

Pollutant: 1. Particulate Matter Emissions

a. **Limitations:** 0.004 grains per dry standard cubic foot of exhaust gas and 0.350 pound per hour. (BACT) [s. NR 415.06(2), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 90 after the start of operation of the process to show compliance with the emission limitation.[27] [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 40 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 0.9 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation to meet the BACT limits. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determined during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.R.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) (a)The fly ash storage facility shall receive fly ash either by bulk tanker truck or fully enclosed pneumatically conveyors. (b) The bulk truck loading be done in a fully enclosed structure. [s. 285.65(3), Wis. Stats.] This condition is established to ensure no fugitive dust is generated by the fly ash storage facility's operation. Also based on this condition no emissions are expected from the equipment used to transfer material to and from the fly ash storage facility. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[27] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

R. S114, P31- Fly Ash Storage Building Exhaust Fan Dust Collector

Pollutant: 2. Visible Emissions

a. Limitations: 10% opacity. [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.R.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

S. S149, P149 - Gypsum XFr Tower No. 1 Dust Collector.

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.005 grains per dry standard cubic foot of exhaust gas and 0.504 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[28] [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 35 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 2.1 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse filter system to meet the BACT limit. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.S.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[28] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

<table>
<tr><td colspan="2">S. S149, P149- Gypsum XFr Tower No. 1 Dust Collector.</td></tr>
<tr><td colspan="2">Pollutant: 2. Visible Emissions</td></tr>
<tr><td colspan="2">a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]
(2) The compliance method in I.S.1.b. shall be used to demonstrate compliance with the visible emission limits. [s. NR 407.09(4)(a)1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.]
(3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]
(4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]</td><td>(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]
(2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]
(3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]
(4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]</td></tr>
</table>

T. S150, P150 – Gypsum XFr Tower No. 2 Dust Collector.	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.005 grains per dry standard cubic foot of exhaust gas and 0.450 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[29] [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 35 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 1.96 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.T.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[29] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

<table>
<tr><td colspan="2">T. S150, P150- Gypsum XFr Tower No. 2 Dust Collector.</td></tr>
<tr><td colspan="2">Pollutant: 2. Visible Emissions</td></tr>
<tr><td colspan="2">a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]
(2) The compliance method in I.T.1.b. shall be used to demonstrate compliance with the visible emission limits. [s. NR 407.09(4)(a)1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.]
(3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]
(4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]</td><td>(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]
(2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]
(3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]
(4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]</td></tr>
</table>

U. S169a, P169a - Fly Ash Silo No 1 Vacuum Exhauster a; S169b, P169b - Fly Ash Silo No 1 Vacuum Exhauster b; S170a, P170a - Fly Ash Silo No 2 Vacuum Exhauster a; S170 b, P170b - Fly Ash Silo No 2 Vacuum Exhauster b
The following emission limits apply to each fly ash silo vacuum exhauster.

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.02 grains per dry standard cubic foot of exhaust gas and 0.369 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code; s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(1) The permittee shall determine the hourly emissions using operating parameters and OEM emission factors. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]
(2) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 30 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 1.0 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]	(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack and file separator system parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the filter separator system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]
(3) Particulate matter emissions shall be controlled using a filter separator system to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code]	
(4) The filter separator system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]	
(5) The permittee shall develop and follow a Malfunction, Prevention and Abatement Plan for the filter separator system. The plan shall identify the specific measures that will be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific measures could include: filter inspection schedule, filter replacement criteria, etc. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	

U. S169a, P169a - Fly Ash Silo No 1 Vacuum Exhauster a; S169b, P169b - Fly Ash Silo No 1 Vacuum Exhauster b; S170a, P170a - Fly Ash Silo No 2 Vacuum Exhauster a; S170 b, P170b - Fly Ash Silo No 2 Vacuum Exhauster b **The following emission limits apply to each fly ash silo vacuum exhauster.**	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The filter separator system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The compliance method in I.U, 1.b. shall be used to demonstrate compliance with the visible emission limits. [s. NR 407.09(4)(a)1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the filter separator system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

V. S171, P171 - Gypsum Hopper Dust Collector

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 1.80 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code; s. 285.65(3), Wis. Stats]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[30] [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 75 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 4.4 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.V.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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[30] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

V. S171, P171- Gypsum Hopper Dust Collector	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The compliance method in I.V, 1.b. shall be used to demonstrate compliance with the visible emission limits. [s. NR 407.09(4)(a)1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

W. S172, P172 – Limestone Loading Table Insertable Bin Vent Filter

Pollutant: 1. Particulate Matter Emissions

a. **Limitations:** 0.004 grains per dry standard cubic foot of exhaust gas and 0.171 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. NR 440.688(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) The permittee shall determine hourly emissions using operating parameters and OEM emission factors. [s. 285.65(3), Wis. Stats.]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 25 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(Ib) The stack inside diameter at the outlet may not exceed 1.4 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) (a) Particulate matter emissions shall be controlled using a bin vent filter system to meet the BACT limits. (b) The limestone loading table will be connected to the limestone unloader and will travel along the dock conveyor. [s. NR 405.08(2), Wis. Adm. Code]

(4) The bin vent filter system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the bin vent filter system shall be determined during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the bin vent filter system shall be maintained within the range identified by condition I.W.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation. [s. NR 440.688(6)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 440.688(6)9b), Wis. Adm. Code, s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack and bin vent filter parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the bin vent filter system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the bin vent filter system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the bin vent filter system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

Note 1: The limestone loading table operation is subject to New Source Performance Standards (NSPS) for particulate matter under s. NR 440.688(3), Wis. Adm. Code and the limit is 0.022 gr/acf. The BACT limit for particulate matter is more restrictive than particulate matter emission limit under NSPS, thus the limestone loading table operation is expected to meet the particulate matter emission limit under NSPS.

W. S172, P172 – Limestone Loading Table Insertable Bin Vent Filter	
Pollutant: 2. Visible Emissions	
a. Limitations: 7% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. NR 440.688(3)(a), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The bin vent filter system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the bin vent filter system shall be maintained within the range identified by condition I.W.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The permittee shall determine compliance with the visible emission limits using EPA approved Method 9. [s. NR 440.688(6)(b)2., Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the bin vent filter system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the bin vent filter system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the bin vent filter system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code] (5) The permittee shall submit written reports of the results of all performance test conducted to demonstrate compliance with the visible emission limits in I.W.2.a. including reports of opacity observations made using EPA Method 9. [s. 285.65(3), Wis. Stats.]

Note 1: The proposed operation is subject to New Source Performance Standards (NSPS) under s. NR 440.688(3), Wis. Adm. Code and the limit is 7% opacity.

X. S178, P178 - Coal Transfer Tower No. 2a Dust Collector and S179, P179 – Coal Transfer Tower No. 2b
The following emission limits apply to each Process

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 2.197 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.31 [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height for S178 shall be at least 80 feet above ground level and the stack height for S179 shall be at least 60.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet for S178 may not exceed 3.7 feet and the stack inside diameter at the outlet for S179 may not exceed 3.2 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) (a) The transfer tower #1 will be completely enclosed structure.
(b) Particulate matter emissions shall be controlled using a fabric filter baghouse system. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.X.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

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31 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

<table>
<tr><td colspan="2">XI. X. S178, P178 - Coal Transfer Tower No. 2a Dust Collector and S179, P179 – Coal Transfer Tower No. 2b
The following emission limits apply to each Process</td></tr>
<tr><td colspan="2">Pollutant: 2. Visible Emissions</td></tr>
<tr><td colspan="2">a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]
(2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.X.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]
(3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]
(4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]
(2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]
(3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]
(4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]</td></tr>
</table>

Note 1: The coal handling/storage operations are subject to s. NR 440.42(3)(c), Wis. Adm. Code (New Source Performance Standards, NSPS requirements) for visible emissions. For these operation, s. NR 440.42(3)(c), Wis. Adm. Code prohibits visible emissions of 20 percent opacity or greater for any coal processes and conveying equipment, coal storage system, or coal transfer and loading system. The limit for opacity established for this process is more restrictive then NSPS limits for opacity, thus the coal handling/storage operation is expected to be in compliance with the opacity emission limits under NSPS.

Y. F29, F29B, F31, S29, S29B, S31 – Inactive Coal Pile A Reclaim & Wind Erosion; F32, S32, - Inactive Coal Pile B Reclaim & Wind Erosion
The following emission limits to each coal pile.

Pollutant: 1. Fugitive Dust (PM/PM10)

a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) (a) Coal loaded out to the inactive coal storage pile shall be compacted in accordance with standard coal pile maintenance procedures. (b) Once compacted, the bulk of the pile will be left undisturbed (inactive). [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) (a) A surfactant (wet suppression spray and/or surface stabilizing agent) or cover material(s), shall be applied to the pile. The surfactant (wet suppression spray and/or surface stabilizing agent) shall be applied to the active area of the pile at the beginning and end of each at stack out and reclaim activity. (b) In addition to the beginning and ending applications, surfactant (wet suppression spray and/or surface stabilizing agent) will also be applied to the active area during reclaim activities whenever any visible emissions are seen beyond the coal pile boundary or whenever, in the option of the rained person, additional surfactant (wet suppression spray and/or surface stabilizing agent) is needed. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(3) (a)The permittee shall conduct weekly inspections of the inactive coal storage pile. (b) Additional surfactant will be applied whenever any visible emissions are seen beyond the coal pile boundary or whenever, in the opinion of the trained person, additional surfactant is needed. (c) In addition to weekly inspections, daily inspections of the active coal pile area, to determine the continued effectiveness of the surfactant, will be conducted by a trained person whenever coal is reclaimed from the pile. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.Y.1.b.(5) shall sign and date the records required in I.Y.1.c.(4) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by condition I.Y.1.b.(6)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the prosperity fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

Y. F29, F29B, F31, S29, S29B, S31 – Inactive Coal Pile A Reclaim & Wind Erosion; F32, S32, - Inactive Coal Pile B Reclaim & Wind Erosion
The following emission limits to each coal pile.

Pollutant: 1. Fugitive Dust (PM/PM10)

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(4) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code] (5) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (6) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	

Z. F33, S33, F33B, S33B – Limestone Storage Pile And Reclaim Activity & Wind Erosion

Pollutant: 1. Fugitive Dust (PM/PM10)

a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
1) (a) The limestone pile shall be wetted by means of a wet suppression system whenever visible emissions are seen beyond the limestone pile boundary or whenever in the opinion of the trained person, additional wet suppression is necessary. (b) Weekly inspections of the limestone storage pile will be conducted to insure the pile contains the proper moisture content to prevent fugitive dust emissions. (c) Daily inspections to determine the continued effectiveness of fugitive dust control measures shall be conducted whenever limestone is reclaimed to the limestone preparation building. (d) Limestone shall be transferred from the pile to the limestone preparation building in a covered conveyor. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (2) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits.[s. NR 415.04(1)(b), Wis. Adm. Code] (3) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (4) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I..Z.1.b.(3) shall sign and date the records required in I.Z.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by condition I.Z.1.b.(4)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

F34, S34, – Inactive Coal Piles – Stackout Drop Point for Pile AA

Pollutant: 1. Fugitive Dust (PM/PM10)

a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) Fixed portions of coal load-out to outdoor storage system shall be conducted within a covered conveyor to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) Dust created during coal load-out shall be suppressed using a liquid spray to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(3) Coal shall be transferred from the conveyor to the storage pile using a telescoping spout to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(4) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code]

(5) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]

(6) The permittee shall ensure that the Trained Person designated:
  (a) Has training to evaluate compliance with Wisconsin air quality regulations, or
  (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or
  (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit.
[s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) (a)The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records including the use of wet suppression system. (b) The records shall consist of the date, time, observations, and any actions taken including the start and end times the wet suppression system is used. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.AA.1.b.(5) shall sign and date the records required in I.AA.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by condition I.AA.1.b.(6)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

BB. F37, S37 – Limestone Barge Unloading; F38, S38 - Limestone StackOut

Pollutant: 1. Fugitive Dust (PM/PM10)

a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 440.688(3), Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) (a) Limestone shall be unloaded from the barge using either a screw auger (or rotary screw) or an enclosed hydraulic clamshell to meet the BACT limits. (b) Limestone load-out to outdoor storage shall be conducted within a covered conveyor equipped with a telescopic chute. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) Dust shall be suppressed using a liquid spray to meet BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(3) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that the Trained Person designated:
- (a) Has training to evaluate compliance with Wisconsin air quality regulations, or
- (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or
- (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit.

[s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.BB.1.b.(4) shall sign and date the records required inI.BB.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by conditionI.BB.1.b.(5)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

CC. F121,F121B, F123, S121, S121B, S123 – Gypsum Dock Side Storage Pile and Barge Loading Activity

Pollutant: 1. Fugitive Dust (PM/PM10)

a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1). Gypsum loaded out to the dock side storage pile shall be covered with a tarp of sufficient size to cover the entire pile to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) A portion of the pile can be maintained in an "active" state to allow for appropriate barge loading activities to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(3) Active portions of the pile shall be wetted by means of a supplemental wet suppression system to a moisture content consistent with proper fugitive dust control whenever visible emissions are seen beyond the gypsum pile boundary or whenever, in the opinion of the trained person, addition wet suppression is necessary. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(4) Weekly inspections of the dock side gypsum storage pile will be conducted to insure that the pile is either covered or contains the proper moisture content to prevent fugitive dust emissions to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(5) Daily inspections of the active area to determine the continued effectiveness of fugitive dust control measures, shall be conducted by the trained person whenever gypsum is loaded out to the barge to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(6) The permittee shall transfer gypsum from the conveyor to the dock-side storage using a telescoping chute to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(7) The permittee shall use a covered conveyor equipped with a telescoping chute or enclosed clamshell when loading gypsum to the barge to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.CC.1.b.(9) shall sign and date the records required inI.CC.1.c.(8) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by conditionI.CC.1.b.(10)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

CC. F121,F121B, F123, S121, S121B, S123 – Gypsum Dock Side Storage Pile and Barge Loading Activity

Pollutant: 1. Fugitive Dust (PM/PM10) [CONTINUED]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(8) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits.[s. NR 415.04(1)(b), Wis. Adm. Code] (9) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (10) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

DD. F122, F124, S122, S124 – Gypsum Drop Side Pile and Barge Loading Drop Points

Pollutant: 1. Fugitive Dust (PM/PM10)

a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) Fixed portions of the gypsum load-out to outdoor storage system shall be conducted within a covered conveyor to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) Dust created during gypsum loadout shall be suppressed using a liquid spray to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(3) Gypsum shall be transferred from the conveyor to the storage pile using a telescoping spout to meet the BACT limits, [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(4) The permittee shall use a covered conveyor equipped with a telescopic chute or enclosed clamshell when loading Gypsum to the pile to meet the BACT limits. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code]

(6) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]

(7) The permittee shall ensure that the Trained Person designated:
  (a) Has training to evaluate compliance with Wisconsin air quality regulations, or
  (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or
  (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit.
[s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.DD.1.b.(6) shall sign and date the records required inI.DD.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by conditionI.DD.1.b.(6)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

EE. F125, S125 – Fuel Ash Reclaim – Maintenance and Front End Loader Excavate Drop to Trucks

Pollutant: 1. Fugitive Dust (PM/PM10)

a. Limitations: (1) No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. (2) The process may be operated only during the hours from 7:00 am to 7:00 PM. The permittee has elected this restriction to ensure the PM10 ambient air quality standards are not exceeded. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(1) The fuel ash reclaim area shall be wetted by means of a wet suppression system whenever visible emissions are seen beyond the area's boundary or whenever, in the opinion of the trained person, additional wet suppression is necessary to meet the BACT limits. [s. 285.65(3), Wis. Stats.] (2) Weekly inspections of the fuel ash reclaim area will be conducted by a trained person to insure that the material to be reclaimed contains adequate moisture content to prevent fugitive dust emissions to meet BACT limits. [s. 285.65(3), Wis. Stats.] (3) In addition to weekly inspections, daily inspections, to determine the continued effectiveness of fugitive dust control measures, shall be conducted by the trained person, whenever fuel ash is reclaimed to meet BACT limits. [s. 285.65(3), Wis. Stats.] (4) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code] (5) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (6) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I.EE.1.b.(5) shall sign and date the records required inI.EE.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by conditionI.EE.1.b.(6)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.] (6) The permittee shall record the start and end times of the operation to demonstrate compliance with condition I.EE.1.a.(2). [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

FF. F44, S141 – S148 – Activities associated at the Caledonia Landfill.

Pollutant: 1. Fugitive Dust (PM/PM10)

a. Limitations: (1) No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. (2) The process may be operated only during the hours from 7:00 am to 7:00 PM. The permittee has elected this restriction to ensure the PM10 ambient air quality standards are not exceeded. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) The landfill shall be wetted by means of a wet suppression system whenever visible emissions are seen beyond the landfill boundary or whenever, in the opinion of the trained person, additional wet suppression is necessary to meet the BACT limits. [s. 285.65(3), Wis. Stats.]

(2) Weekly inspections of the materials storage landfill will be conducted by a trained person to insure that the material to be restored and reclaimed contains adequate moisture content to prevent fugitive dust emissions to meet BACT limits. [s. 285.65(3), Wis. Stats.]

(3) In addition to weekly inspections, daily inspections, to determine the continued effectiveness of fugitive dust control measures, shall be conducted by the trained person, whenever fuel ash is reclaimed to meet BACT limits. [s. 285.65(3), Wis. Stats.]

(4) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code]

(5) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]

(6) The permittee shall ensure that the Trained Person designated:
- (a) Has training to evaluate compliance with Wisconsin air quality regulations, or
- (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or
- (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit.

[s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.FF.1.b.(5) shall sign and date the records required inI.FF.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by conditionI.FF.1.b.(6)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

(6) The permittee shall record the start and end times of the operation to demonstrate compliance with condition I.FF.1.a.(2). [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

GG. F174, F173, S173, S174 – Front End Loader reclaim of bottom ash – SCPC units to trucks.

Pollutant: 1. Fugitive Dust (PM/PM10)

a. Limitations: (1) No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. (2) The process may be operated only during the hours from 7:00 am to 7:00 PM. The permittee has elected this restriction to ensure the PM10 ambient air quality standards are not exceeded. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) Dust created during bottom ash reclamation activities shall be suppressed using a water spray to meet BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]

(4) The permittee shall ensure that the Trained Person designated:
    (a) Has training to evaluate compliance with Wisconsin air quality regulations, or
    (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or
    (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit.
[s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.GG.1.b.(3) shall sign and date the records required inI.GG.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by conditionI.GG.1.b.(4)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

(6) The permittee shall record the start and end times of the process to demonstrate compliance with condition I.GG.1.a.(2). [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

<table>
<tr><td colspan="2">HH. F134 – Facility Haul Roads</td></tr>
<tr><td colspan="2">Pollutant: 1. Fugitive Dust (PM/PM10)</td></tr>
<tr><td colspan="2">a. Limitations: The permittee shall apply Best Available Control Technology (BACT). BACT shall be met by the use a) paving the haul roads. b) Use of trucks washing stations and c) of a high efficiency vacuum street sweeper. [s. NR 405.08, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) All facility haul roads shall be paved to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code]
(2) All facility haul roads shall be vacuum swept, at minimum, twice daily (except when weather conditions exist such that precipitation and/or ambient temperature would control fugitive emissions or prevent vacuum sweeping's effectiveness). If, in the opinion of the trained person additional roadways vacuum sweeping is necessary to prevent inappropriate fugitive dust emissions it will be conducted as soon as practical. [s. NR 405.08, Wis. Adm. Code]
(3) Truck washing stations shall be installed and used near four locations where removal of mud, dirt and dust must occur, the SCPC ash loading stations, the IGCC slag loading station, the fuel ash reclaim area, and the Caledonia landfill area. [s. NR 405.08, Wis. Adm. Code]
(4) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]</td><td>(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]
(2) The permittee shall ensure that the trained Person at the site keep(s) daily records consisting of the date and time roadway sweeping occurred or the date and reasons why it did not. [s. 285.65(3), Wis. Stats., s. NR 415.04(1)(b), Wis. Adm. Code]</td></tr>
</table>

II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2.
The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 1. Particulate Matter Emissions

a. Limitations: (1) The emissions may not exceed 0.011 pound per million Btu including startup and shut down. (BACT); (2) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[32] [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I. II.1.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 275.0 feet above ground evel. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 20.0 eet. [s. 285.65(3), Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire only fire syngas as the primary fuel with fuel oil having a maximum sulfur content of 0.003% sulfur by weight for start up. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (5) The permittee shall demonstrate good combustion practices by: (a) monitoring appropriate combustion operating parameters. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, test procedures in US EPA Method 5, including backhalf (Method 202) or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. (s. NR 439.04(1)(d), Wis. Adm. Code) (2) During operation, the facility will monitor and record the following operating parameters on an hourly basis: (a) Combustion turbine inlet temperature (b) Combustion turbine firing temperature (c) Combustion turbine exhaust temperature (d) Coal fuel flow rate [s. 285.65(10), Wis. Stats.] (4) During initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.II.1.c.(3) to establish normal operational ranges for use as a compliance demonstration. [s. 285.65(10), Wis. Stats.] (5) The permittee shall install, calibrate, and maintain instrumentation to monitor the parameters identified by condition I.II.1.c.(3)a. – d. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

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[32] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

I.II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2.
The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM10)

a. Limitations: (1) The emissions may not exceed 0.011 pound per million Btu including startup and shut down. (BACT); (2) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[33] [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall perform the compliance emission tests required under condition I.II.2.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(3) <u>Stack Parameters</u>: These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 275.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 20.0 feet. [s. 285.65(3), Stats., s. NR 406.10, Wis. Adm. Code]

(4) The permittee shall fire only fire syngas as the primary fuel with fuel oil having a maximum sulfur content of 0.003% sulfur by weight for start up. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(5) The permittee shall demonstrate good combustion practices by:
(a) monitoring appropriate combustion operating parameters. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, test procedures in US EPA Method 5, including backhalf (Method 202) or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. (s. NR 439.04(1)(d), Wis. Adm. Code)

(3) During operation, the facility will monitor and record the following operating parameters on an hourly basis:
(a) Combustion turbine inlet temperature
(b) Combustion turbine firing temperature
(c) Combustion turbine exhaust temperature
(d) Coal fuel flow rate
[s. 285.65(10), Wis. Stats.]

(4) During initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.II.2.c.(3) to establish normal operational ranges for use as a compliance demonstration. [s. 285.65(10), Wis. Stats.]

(5) The permittee shall install, calibrate, and maintain instrumentation to monitor the parameters identified by condition I.II.2.c.(3)a. – d. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

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[33] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

II. S39, B39 – Integrated Gasification Combined Cycle (IGCC) 1; S40, B40 – Integrated Gasification Combined Cycle (IGCC) 2. The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 3. Sulfur Dioxide Emissions

a. Limitations: (1) (a) 0.015 percent by volume at 15% O2 on a dry basis. (NSPS) [s. NR 440.50(4)(a), Wis. Adm. Code]; or (b) fuel sulfur content less than or equal to 0.8% by weight. (NSPS) [s. NR 440.50(4)(b), Wis. Adm. Code]; (2) 0.03 pound per million Btu heat input, based on a 24-hour average including startup and shut down. (BACT) [s. NR 405.08(2), Wis. Adm. Code]; (3) 40 ppmvd sulfur in the gasified (syngas) fuel (expressed as hydrogen sulfide). (BACT) [s. NR 405.08(2), Wis. Adm. Code; (4) 278 tons in any 12 consecutive months for all periods, including startup and shut down, (BACT) [s. 405.08(2), Wis. Adm. Code]; (5) The sulfur content of fuel oil to be sued during periods of start-up and shut down may not exceed 0.003% by weight. (BACT) [s. NR 405.08(2), Wis. Adm. Code]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.34 [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall perform the compliance emission tests required under condition I. II.3.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 275.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 20.0 feet. [s. 285.65(3), Stats., s. NR 406.10, Wis. Adm. Code]

(4) Each combustion turbine may only be fired on syngas, except for periods of startup and load stabilization when distillate fuel oil may also be utilized as a fuel. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(5) Sulfur Dioxide Emission shall be controlled by a syngas cleanup system. [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.20(4)(a)1., Wis. Adm. Code]

(6) Compliance with the sulfur dioxide emission limit contained in I.II.3.a. (3) shall be demonstrated either through the use of (a) daily syngas sampling and analysis or (b) through the use of a sulfur dioxide continuous emission monitoring system (CEMs). [s. NR 405.08(2), Wis. Adm. Code]

(6) Compliance with the sulfur dioxide BACT emission limit contained in I.II3.a.(3) constitutes compliance with the emission limit contained in I.II.3.a.(1) and (2) as I.II.3.a.(3) is a more restrictive limit. [s. 285.65(3), Wis. Stats.]

(7) The sulfur content of fuel oil to be used during periods of start-up and load stabilization may not exceed 0.003% by weight. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Sulfur Dioxide Emissions: Whenever compliance emission testing is required, test procedures in US EPA Method 6, 6A or 6C or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(2), Wis. Adm. Code]

(2) The daily syngas sampling and analysis provisions of I.II.3.b.(5)(a) shall be determined according to ASTM D1072-90, "Standard Test Method for Total Sulfur in Fuel Gases", ASTM D4468-85 "Standard test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Radiometric Colorimetry", ASTM D5504-94 "Standard test Method for Determination of Sulfur Compound in Natural Gas and gaseous Fuels by Gas Chromatography and Chemiluminescence", or ASTM 3246-81 "Standard test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry". [s. NR 439.08(2)(b), Wis. Adm. Code]

(3) The provision of I.II.3.b.(5)(b) shall be satisfied through the installation and use of a continuous emissions monitoring system (CEMs) for sulfur dioxide and carbon dioxide or oxygen content of the flue gases at each location where sulfur dioxide emissions are monitored within 60 days after initial startup of the combustion turbine. The CEMs shall be calibrated within 90 days after initial startup of the combustion turbine. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75 and s. NR 439.06(6)(b), Wis. Adm. Code requirements. [s. 285.65(3), Wis. Stats., s. NR 439.06, Wis. Adm. Code]

(4) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code]

(5) The sulfur content provisions of I.II.3.b.(7) shall be determined according to ASTM D129-95, Standard Test Method for Sulfur in Petroleum Products, ASTM D1552-95, Standard test Method for Sulfur in Petroleum Products, or ASTM D4294-98 Standard test Method for Sulfur in Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectroscopy, respectively. [s. NR 439.08(2)(b), Wis. Adm. Code]

(6) The permittee shall comply with NSPS monitoring of operations requirements per s. NR 440.50(5), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 440.50(5), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(7) The permittee shall use test methods and procedure per s. NR 440.50(6), Wis. Adm. Code to comply with the NSPS emission limits. [s. NR 440.50(6), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

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34 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

I.II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2.
The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 4. Nitrogen Oxides Emissions

Limitations: (1) The emissions may not exceed 15 ppmdv, corrected to 15% oxygen on a 30 day rolling average basis, not including periods of startup and shut down, on a 30 day rolling basis. (BACT); (2) The emissions may not exceed 15 ppmdv, corrected to 15% oxygen on a 30 day rolling average basis, including periods of startup and shut down, averaged over any consecutive 12 month period. (BACT); (3) 75 ppm @ 15% Oxygen. (NSPS); (3) The use of a diluent injection system (DIS) (BACT). [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.50(3), Wis. Adm. Code, s. NR 428.04(2)(g)3., Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[35] [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall perform the compliance emission tests required under condition I.II.4.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 275.0 feet above ground level. [s. 285.65(3), Wis. Stats. , s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 20.0 feet. [s. 285.65(3), Stats., s. NR 406.10, Wis. Adm. Code]

(4) Nitrogen Oxides Emission shall be controlled by a diluent injection system to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(5) The permittee shall demonstrate compliance with the nitrogen oxides emission limit contained in I.II.4.a.(1) using emissions data measured by the continuous emission monitoring system required by I.II.4.c.(2) as follows:

(a) Daily average concentration shall be calculated each calendar day by combining the nitrogen oxides concentration and diluent concentration (in % O2 or % CO2) measurement consistent with the procedures specified in 40 CFR 75 Appendix F. [s. 285.65(10), Wis. Stats.]
(b) Each monthly nitrogen oxide emissions average shall be calculated by dividing the sum of all daily averages calculated during the month by the number of daily average calculated during the month. [s. 285.65(3), Wis. Stats.]
(c) Each 12-month nitrogen oxide emissions average shall be calculated as the average of the past 12 monthly emissions average. [s. 285.65(3), Wis. Stats.]

(6) Compliance with the nitrogen oxides BACT emission limit contained in I.II.4.a.(1) constitutes compliance with the NSPS emission limit as the BACT emission limits is more restrictive then the NSPS emission limit. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Nitrogen Oxides Emissions: Whenever compliance emission testing is required, test procedures in US EPA Method 7or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(6), Wis. Adm. Code]

(2) The permittee shall install and operate continuous emissions monitoring system (CEMs) for NOx and carbon dioxide or oxygen within 60 days after initial start up of IGCC. The CEMs shall be calibrated within 90 days after initial start up of the IGCC. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75 and s. NR 439.06(6)(b), Wis. Adm. Code requirements. [s. 285.65(3), Wis. Stats., s. NR 439.06, Wis. Adm. Code]

(3) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code]

(4) The permittee shall comply with the general and specific monitoring requirements under s. NR 428.04(3)(a) and (b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(5) The permittee shall comply with all the recordkeeping and reporting requirements under s. NR 428.04(4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(6) The permittee shall comply with all the requirements for monitoring, installation, certification, data accounting, compliance dates and reporting data prior to initial certification as required under s. NR 428.07(1)(b), Wis. Adm. Code, s. NR 428.07(2)(b)2, Wis. Adm. Code, s, NR 428.07(3), Wis. Adm. Code. [s. 285.65(3), Wis. Stats.]

(7) The permittee shall monitor NOx and heat input per s. NR 428.08(1)(e), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(8) The permittee shall submit quarterly reports per s. NR 428.09(2), (3) and (4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(9), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

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[35] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2. The following emission limits apply to each IGCC Combustion Turbine.	
Pollutant: 4. Nitrogen Oxides Emissions [CONTINUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(7) The permittee shall keep track of the startup and shut down time by monitoring the fuel combusted in the turbine. Startup periods begin with the firing of any fuel in the combustion turbine, and end with the introduction of syngas to the combustion turbine. Shut down period begin with the cessation of syngas flow to the combustion turbine, and end with the cessation of all fuel firing.[s. 285.65(3), Wis. Stats.]	(9) The permittee shall comply with NSPS monitoring of operations requirements per s. NR 440.50(5), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 440.50(5), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (10) The permittee shall use test methods and procedure per s. NR 440.50(6), Wis. Adm. Code to comply with the NSPS emission limits. [s. NR 44.50(6), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (11) The permittee shall keep records required under condition I.II.4.b.(5)(b), (c) and I.II.4.b.(7). [s. 285.65(3), Wis. Stats.]

I. S39, B39 – Integrated Gasification Combined Cycle (IGCC) Combustion Turbine 1; S40, B40 – Integrated Gasification Combined Cycle (IGCC) Combustion Turbine 2.
The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 5. Carbon Monoxide Emissions

a. Limitations: (1) The emissions may not exceed 0.030 pound per million Btu on a 24-hour rolling average, excluding periods of startup and shut down. (BACT); (2) The use of good combustion practices. (BACT) ; (3) 624 pounds per hour during any one hour period, including startup and shut down. (4) 282 tons in any 12 consecutive months for all periods, including startup and shut down. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.36 [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall perform the compliance emission tests required under condition I. II.5.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(3) Carbon Monoxide Emissions shall be controlled using good combustion practices to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(4) The permittee shall demonstrate compliance with the BACT limit by:(a) monitoring appropriate combustion operating parameters or (b) through the use of a CO CEMs. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(5) The permittee shall demonstrate compliance with the carbon monoxide emission limits using data from a continuous emissions monitoring system (CEMs) for CO and carbon dioxide or oxygen required under condition I.II.5.c.5 as follows:

(a) Daily average shall be determined by calculating the arithmetic average of all applicable hourly emission rates for a calendar day.

(b) The hourly emission rate shall be calculated by combining the CO concentration and diluent concentration (in % O2 or % CO2) measurement consistent with the procedures specified in 40 CFR Part 75 Appendix F. The conversion factor, (k), shall be 0.7266 x 10-7 lb CO/ft3 - ppm.

(c) The annual emission limit in I.II.a.(4) shall be calculated using and totally the hourly calculated emission rate. [s. 285.65(3), Wis. Stats.]

(6) The permittee shall keep track of the startup and shut down time by monitoring the fuel combusted in the turbine. Startup periods begin with the firing of any fuel in the combustion turbine, and end with the introduction of syngas to the combustion turbine. Shutdown periods begin with the cessation of syngas flow to the combustion turbine, and end with the cessation of all fuel firing. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Carbon Monoxide Emissions: Whenever compliance emission testing is required, test procedures in US EPA Method 10 or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(4), Wis. Adm. Code]

(2) During operation, the facility will monitor and record the following operating parameters on an hourly basis:
(a) Combustion turbine inlet temperature
(b) Combustion turbine firing temperature
(c) Combustion turbine exhaust temperature
(d) Coal flow rate
[s. 285.65(10), Wis. Stats.]

(3) During initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.II.5.c.(2) to establish normal operational ranges for use as a compliance demonstration. [s. 285.65(10), Wis. Stats.]

(4) The permittee shall install, calibrate, and maintain instrumentation to monitor the parameters identified by condition I.II.1.c.(3)a. – d. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(5) The permittee shall install and operate continuous emissions monitoring system (CEMs) for CO and carbon dioxide or oxygen within 60 days after initial start up of IGCC. The CEMs shall be calibrated within 90 days after initial start up of the IGCC. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75 and s. NR 439.06(6)(b), Wis. Adm. Code requirements. [s. 285.65(3), Wis. Stats., s. NR 439.06, Wis. Adm. Code]

(6) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code]

(7) The permittee shall keep records required under condition I.II.5.b.(5)(b), (c) and I.II.5.b.(6). [s. 285.65(3), Wis. Stats.]

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36 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

II. S39, B39 – Integrated Gasification Combined Cycle (IGCC) Combustion Turbine 1; S40, B40 – Integrated Gasification Combined Cycle (IGCC) Combustion Turbine 2.
The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 6. Volatile Organic Compound Emissions

a. Limitations: (1) 0.0017 pound per million Btu heat input excluding periods of startup and shut down averaged over any consecutive 24-hour period. Startup periods begin with the firing of any fuel in the combustion turbine, and end with the introduction of syngas to the combustion turbine. Shutdown periods begin with the cessation of syngas flow to the combustion turbine, and end with the cessation of all fuel firing. (LAER); (2) 3.64 pounds per hour excluding periods of startup and shut down, averaged over any consecutive 24-hour period. (LAER); (3) 16.93 tons in any 12 consecutive months for all periods, including startup and shut down. (LAER); (4) The use of good combustion practices. (LAER) [s. NR 408.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.37 [s. NR 439.07, Wis. Adm. Code]	(1) <u>Reference Test Method for VOC Emissions:</u> Whenever compliance emission testing is required, test procedures in US EPA Method 25 or 18 or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code]
(2) The permittee shall perform the compliance emission tests required under condition I.II.6.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(2) During operation, the facility will monitor and record the following operating parameters on an hourly basis: (a) Combustion turbine inlet temperature (b) Combustion turbine firing temperature (c) Combustion turbine exhaust temperature (d) Coal flow rate [s. 285.65(10), Wis. Stats.]
(3) Volatile Organic Compound Emissions shall be controlled using good combustion practices to meet LAER emission limit. [s. NR 408.08(2), Wis. Adm. Code]	(3) During initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.II.5.c.(2) to establish normal operational ranges for use as a compliance demonstration. [s. 285.65(10), Wis. Stats.]
(4). The permittee shall demonstrate compliance with the LAER limit by: (a) monitoring appropriate combustion operating parameters or (b) through the use of a CO CEMs. [s. 285.65(3), Wis. Stats., s, 285.65(10), Wis. Stats.]	(4) The permittee shall install, calibrate, and maintain instrumentation to monitor the parameters identified by condition I.II.5.c.(3)a. – b. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]
(5) CO emissions data measured by the CEM system shall be used to demonstrate compliance with the LAER emission limit by using the following equation to keep daily, monthly and annual VOC emissions records: VOC actual = VOC limit X (CO actual/CO limit) [s. 285.65(3), Wis Stats., s. 285.65(10), Wis. Stats.]	(5) The permittee shall install and operate continuous emissions monitoring system (CEMs) for CO and carbon dioxide or oxygen within 60 days after initial start up of IGCC. The CEMs shall be calibrated within 90 days after initial start up of the IGCC. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75 and s. NR 439.06(6)(b), Wis. Adm. Code requirements. [s. 285.65(3), Wis. Stats., s. NR 439.06, Wis. Adm. Code]
	(6) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code]
	(7) The permittee shall keep records required under condition I.II.6.b.(5). [s. 285.65(3), Wis. Stats.]

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37 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

<table>
<tr><td colspan="2">II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion turbine (IGCC) 2.
The following emission limits apply to each IGCC Combustion Turbine.</td></tr>
<tr><td colspan="2">Pollutant: 7. Lead Emissions</td></tr>
<tr><td colspan="2">a. Limitations: (1) The emissions may not exceed 0.0000257 pound per million Btu including startup and shut down. (BACT); (2) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[38] [s. NR 439.07, Wis. Adm. Code]
(2) The permittee shall perform the compliance emission tests required under condition I.II.7.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]
(3) Lead Emissions shall be controlled using good combustion practices and firing syngas as the primary fuel with 0.003% low sulfur fuel for startup to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]
(4). The permittee shall demonstrate compliance with the BACT limit by complying with the conditions in I.II.1.b. [s. 285.65(3), Wis. Stats.; s, 285.65(10), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Lead Emissions:</u> Whenever compliance emission testing is required, test procedures in US EPA Method 12, or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code]</td></tr>
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[38] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

I.II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2.
The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 8. Mercury Emissions

a. Limitations: (1) The emissions may not exceed 0. 56lb/trillion Btu based on a 12-month rolling average including startup and shut down. (BACT); (2) The use of carbon bed or equivalent control technology capable of achieving 95% control of mercury emissions. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats] See Note 1

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[39] [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall perform the compliance emission tests required under condition I.II.8.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(3) Mercury Emissions shall be controlled using Carbon bed or filter containing similar material in the synthetic gas specifically designed to control emissions of mercury contained in the fuel supply or such requirement for the effective control of mercury emissions as may be promulgated by USEPA as the MACT standard applicable to new stationary combustion turbines of an IGCC facility to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(4) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the carbon bed and (b) A list of items that will be checked and maintained and their frequency, to ensure that the carbon bed system is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(5) The permittee shall monitor uncontrolled mercury emissions through coal sampling and analysis. Such testing occur on a monthly basis according to the relevant provisions of s. NR 439.08, Wis. Adm. Code as applied to mercury content in the coal. The permittee shall also monitor monthly average coal higher heating value. [s. NR 405.08, Wis. Adm. Code]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Mercury Emissions: Whenever compliance emission testing is required, test procedures in US EPA Method 29 or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall record information on the maintenance required in condition I.II.8.b.(4). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

(3) The data obtained form the mercury content from the coal sampling and analysis shall be kept at the facility for a period of five years. [s. 285.65(3), Wis. Stats.]

Note 1: The BACT Limit for Mercury is based on uncontrolled mercury emissions of 11.2 pounds per trillion Btu and a control efficiency of 95%.

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[39] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

I.II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion turbine (IGCC) 2.
The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 9. Visible Emissions

a. Limitations: 20% opacity. [s. NR 431.05, Wis. Adm. Code]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Opacity shall be controlled using good combustion practices. [s. 285.65(3), Wis. Stats.] (2) The compliance demonstration methods identified in I.II.1.b. shall be used to demonstrate compliance with the visible emission limit. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 or Reference Method 22 of Appendix A, 40 CFR Part 60 shall be used to demonstrate compliance or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall install, calibrate, maintain and operate a continuous monitoring system, and record the output to the system, for measuring the opacity of emissions discharged to the atmosphere. [s. 285.65(10), Wis. Stats.] (3) Continuous opacity monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code]

II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2.
The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 10. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.

a. Limitations: (1) The permittee shall use syngas cleanup system and use good combustion practices to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall use syngas cleanup system and good combustion practices to comply with the case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with good combustion practices and meet the VOC emission limits to comply with case by case MACT for organic HAPs. [s. 285.65(13), Wis. Stats., s. 285.65(3), Wis. Stats., 40 CFR Part 63, Subpart B]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The inorganic solid HAPs, acid gas HAPs and organic HAPs shall be controlled using a syngas clean up system and good combustion practices. [s. 285.65(3), Wis. Stats.] (2) The compliance demonstration methods in I.II.1.b., I.II.3.b., I.II.6.b., shall be used as compliance demonstration techniques for inorganic solid HAPs, inorganic acid HAPs, and organic HAPs. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs: Whenever compliance emission testing is required an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The testing, recordkeeping and monitoring requirements contained in I.II.1.c., I.II.3.c. shall be used as compliance methods for I.II.10.b.(2). [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2.
The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 11. Sulfuric Acid Mist

Limitations: (1) The emissions may not exceed 0.0005 pound per million Btu, based on a 3-hour average including startup and shut down. (BACT); (2) The use of gas clean up system. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) (1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[40] [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I. II.11.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) Sulfuric acid mist emissions shall be controlled by a gas clean up system. [s. NR 405.08(2), Wis. Adm. Code] (4) The compliance demonstration method identified in section I.II.3.b. shall be used as compliance demonstration techniques for sulfuric acid mist emission limitation. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Sulfur Acid Mist Emissions: Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code]

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[40] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

JJ. S41, P41 – Sulfuric Acid Plant #1; S42, P42, Sulfuric Acid Plant #2
The following emissions limits apply to each sulfuric acid plant.

Pollutant: 1. Sulfur Dioxide Emissions

a. Limitations: (1) The emissions may not exceed 4.0 pounds per tons of 100% sulfuric acid produced. (BACT); (2) The use of a dual absorption plant and fiber mist eliminators to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.24(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[41] [s. NR 439.07, Wis. Adm. Code]	(1) Reference Test Method for Sulfur Dioxide Emissions: Whenever compliance emission testing is required, US EPA Method 6, 6A, 6C or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(2), Wis. Adm. Code]
(2) The permittee shall perform the compliance emission tests required under condition I.JJ.1.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(2) The permittee shall record information on the maintenance required in condition I.JJ.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]
(3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 150.0 feet above ground evel. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 3.5 eet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]	(3) The permittee shall install and operate continuous emissions monitoring system (CEMs) for sulfur dioxide within 60 days after initial start up of the sulfuric acid plant. The CEMs shall be calibrated within 90 days after initial start up of the sulfuric acid plant. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 60 and s. NR 439.06(6)(b), Wis. Adm. Code requirements. A copy of s. NR 440.24, Wis. Adm. Code requirements attached with the permit. [s. 285.65(3), Wis. Stats., s. NR 440.24(5), Wis. Adm. Code, s. NR 439.06, Wis. Adm. Code]
(4) The permittee shall control sulfur dioxide emissions through the use of a dual absorption plan and fiber mist eliminator. [s. NR 405.08(2), Wis. Adm. Code]	(4) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 440.24(5) and (6), Wis. Adm. Code and s. NR 439.09, Wis. Adm. Code. A copy of s. NR 440.24, Wis. Adm. Code requirements attached with the permit. [s. NR 439.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]
(5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fiber mist eliminator and (b) A list of items that will be checked and maintained and their frequency, to ensure that the dual absorption plan and fiber mist eliminator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(5) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

Note 1: The sulfuric acid plant is subject to New Source Performance Standards (NSPS) for sulfur dioxide. The sulfur dioxide emissions limit to not exceed 4.0 pounds per tons 100% sulfuric acid produced per s. NR 440.24(3), Wis. Adm. Code. The sulfuric acid plant is expected to comply with the sulfur dioxide emission limits under NSPS.

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[41] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

JJ. S41, P41 – Sulfuric Acid Plant #1; S42, P42, Sulfuric Acid Plant #2
The following emissions limits apply to each sulfuric acid plant.

Pollutant: 2. Sulfur Acid Mist Emissions

a. Limitations: (1) The emissions may not exceed 0.128 pounds per tons. (BACT).; (2) The use of a dual absorption plant and fiber mist eliminators to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.24(4)(a), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[42] [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I.JJ.2.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) The permittee shall control sulfuric acid mist emissions through the use of a dual absorption plan and fiber mist eliminator. [s. NR 405.08(2), Wis. Adm. Code] (4) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fiber mist eliminator and (b) A list of items that will be checked and maintained and their frequency, to ensure that the dual absorption plan and fiber mist eliminator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s, 285.65(10), Wis. Stats.] (5) The permittee shall determine compliance with sulfuric acid emission limits per test methods and procedures identified in s. NR 440.24(6)(b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Sulfuric Acid Mist Emissions:</u> Whenever compliance emission testing is required, US EPA Method 8 or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record information on the maintenance required in condition I.JJ.2.b.(4). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Note 1: The sulfuric acid plant is subject to New Source Performance Standards (NSPS) for sulfuric acid mist emissions. The sulfuric acid mist emissions limit to not exceed 0.15 pounds per tons 100% sulfuric acid produced per s. NR 440.24(4)(a), Wis. Adm. Code. The BACT limit for sulfuric acid mist is more restrictive then the NSPS limit for sulfuric acid mist. The sulfuric acid plant is expected to meet the NSPS limit for sulfuric acid mist.

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[42] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

JJ. S41, P41 – Sulfuric Acid Plant #1; S42, B42, Sulfuric Acid Plant #2
The following emissions limits apply to each sulfuric acid plant.

Pollutant: 3. Visible Emissions

a. Limitations: 10% opacity [s. NR 405.09, Wis. Adm. Code, s. NR 440.24(4)(a), Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(13), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Compliance emission tests to demonstrate compliance with the visible emission limit shall be conducted within 60 days after the start of the initial operation. [s. 285.65(3), Wis. Stats.] (2) The permittee shall determine compliance with visible emission limits per test methods and procedures identified in s. NR 440.24(6)(b)4., Wis. Adm. Code. A copy of these requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

KK. S43, P43 – Gasifier Flare

Pollutant: 1. Particulate Matter Emissions (PM/PM10)

a. Limitations: (1) The use of good flare design and limiting number of startup and shut down cycles to 35 per 12 contiguous month period to meet BACT. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) <u>Stack Parameters</u>. These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 150.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 6.0 feet. [s. 285.65(3), Stats., s. NR 406.10, Wis. Adm. Code] (2) The flare shall be operated at all times when the IGCC unit is operating. [s. 285.65(3), Wis. Stats.] (3) The permittee shall limit the number of startup and shut down cycles to 35 per 12 contiguous month period. [s. NR 405.08(2), Wis. Adm. Code] (4) The permittee shall install and operate a temperature monitoring and continuous recording system to ensure that the flare is operating. [s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(1) The permittee shall retain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (2) The permittee shall record the number of startup and shut downs to demonstrate compliance with condition I.KK.1.b.(3). [s. NR 439.06(1), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) The permittee shall record date and time the flare was inoperable for each event the flare was inoperable. [s. 285.65(3), Wis. Stats.]

KK. S43, P43 – Gasifier Flare	
Pollutant: 2 Visible Emissions	
a. Limitations: 0% opacity or number 1 on the Ringlemann chart. See Note 1 [s. NR 431.05, Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(13), Wis. Stats., s. NR 440.18(3)(a), Wis. Adm. Code]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Compliance emission tests to demonstrate compliance with the visible emission limit shall be conducted within 180 days after the start of the initial operation. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

Note 1: S. NR 440.18(3)(a), Wis. Adm. Code requires flares to be designed and operated with no visible emissions as determined by the methods specified in s. NR 440.18(6), Wis. Adm. Code except for periods not to exceed a total of five minutes during any 2 consecutive hours.

LL. B44, S44 – IGCC Auxiliary Boiler

Pollutant: 1 Particulate Matter

b. Limitations: (1) The emissions may not exceed 0.007 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.020 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.207(4) (c), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[43] [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall determine the hourly emissions using fuel consumption records and emissions factor determined by stack testing. [s. 285.65(3), Wis. Stats.]

(3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 140.0 feet above ground evel. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 4.0 eet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(4) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(6) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.1.a. (4). [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60 and US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall keep records on the heat input used as required in condition I.LL.1.b.(6). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) The permittee shall record information on the maintenance required in condition I.LL.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Note 1: The IGCC auxiliary boiler is subject to NSPS requirements for particulate matter (PM) under s. NR 440.207(4)(c), Wis. Adm. Code. The only New Source Performance Standards (NSPS) standard that will be applicable to the boiler for PM is in the form of an opacity standard when fuel oil is fired per s. NR 440.207(4)(c), Wis. Adm. Code.

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[43] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

LL. S44, B44 – IGCC Auxiliary Boiler

Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM_{10})

Limitations: (1) The emissions may not exceed 0.007 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.020 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[44] [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall determine the hourly emissions using fuel consumption records and emissions factor determined by stack testing. [s. 285.65(3), Wis. Stats.]

(3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 140 feet above ground evel. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 4.0 eet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(4) The permittee shall fire natural gas and/or fuel having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(6) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.2.a. (4). [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall keep records on the heat input used as required in condition I.LL.2.b.(6). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) The permittee shall record information on the maintenance required in condition I.LL.2.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

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[44] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

LL. S44, B44 – IGCC Auxiliary Boiler

Pollutant: 3. Sulfur Dioxide

a. Limitations: (1) The emissions may not exceed 0.0012 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.0032 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.207(3)(d), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption records, fuel sulfur content and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) A representative sample shall be taken from each fuel lot of fuel oil received. The sample shall be analyzed by the permittee for the sulfur content by weight using procedures outline in s. NR 439.08(2), Wis. Adm. Code and the analysis shall be retained by the permittee for a period of at least five years. [s. 285.65(3), Wis. Stats.]

(5) The Department will accept, in lieu of an analysis on each fuel lot under (4) above, an analysis of a representative sample of the fuel lot of distillate fuel oil from which the fuel lot was taken. [s. 285.65(3), Wis. Stats., s. NR 440.207(5)(h), Wis. Adm. Code]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Sulfur Dioxide Emissions: Whenever compliance emission testing is required, US EPA Method 6, 6A or 6C shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(2), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.LL.3.b.(8). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.LL.3.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

(5) The permittee shall keep records required under condition I.LL.3.b.(4) – (7). [s. NR 439.04(1)(d), Wis. Adm. Code]

(6) The permittee shall comply with the NSPS reporting and recordkeeping requirements per s. NR 440.207(9), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. 285.65(3), Wis. Stats.]

(7) The permittee shall keep records of the fuel supplier certification. The certification shall include the following information:

1. For distillate oil:
   a. The name of the oil supplier; and
   b. A statement from the oil supplier that the oil complies with the specification under the definition of distillate oil in s. NR 440.207(2)(g), Wis. Adm. Code

[s. 285.65(3), Wis. Stats., s. NR 440.207(9)(f), Wis. Adm. Code]

Note 1: The New Source Performance Standard (NSPS) for sulfur dioxide in s. NR 440.207(3) (d), Wis. Adm. Code will be applicable to the IGCC auxiliary boiler only when fuel oil is fired and is 0.50 pound per million Btu heat input or combust oil having a sulfur content of 0.5 percent by weight. The BACT emission limit for sulfur dioxide is more restrictive then the NSPS limit for sulfur dioxide, thus the IGCC auxiliary boiler is expected to meet the NSPS limit for sulfur dioxide.

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 3. Sulfur Dioxide (continued)	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(6) The permittee shall retain copies of its distillate fuel oil supplier's fuel sulfur and heat content analyses at the facility for each fuel lot of distillate fuel oil received pursuant to 40 CFR 60.334 for a period of five years. [s. NR 439.04(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall further obtain certification from the fuel supplier that the applicable methods in s. NR 439.08(2), Wis. Adm. Code, were followed, if applicable, by the supplier in the preparation of said sulfur and heat content analyses. The fuel lot's quantity of fuel oil shall be included with the copies of these analyses. The fuel supplier certification shall include the information identified in condition I.LL.3.c.(7). [s. 285.65(3), Wis. Stats.] (8) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.3.a. (4). [s. 285.65(3), Wis. Stats.]	

LL. S44, B44 – IGCC Auxiliary Boiler

Pollutant: 4. Oxides of Nitrogen (NOx)

a. Limitations: (1) The emissions may not exceed 0.050 pound per million Btu when firing natural gas based on a 30-day rolling average. (BACT); (2) The emissions may not exceed 0.090 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight oil based on a 30-day rolling average. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. NR 428.04(2)(a)2., and 3., Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption record and vendors or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.4.a. (4). [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Nitrogen Oxide Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60, US EPA Method 7 or an alternate method approved in writing by the Department shall be used to demonstrate compliance.
[s. NR 439.06(6), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.LL.4.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.LL.4.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

(5) The permittee shall comply with the general and specific monitoring requirements under s. NR 428.04(3)(a) and (b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(6) The permittee shall comply with all the recordkeeping and reporting requirements under s. NR 428.04(4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(7) The permittee shall comply with all the requirements for monitoring, installation, certification, data accounting, compliance dates and reporting data prior to initial certification as required under s. NR 428.07(1)(b), Wis. Adm. Code, s. NR 428.07(2)(b)2, Wis. Adm. Code, s, NR 428.07(3), Wis. Adm. Code. [s. 285.65(3), Wis. Stats.]

(8) The pemittee shall monitor NOx and heat input per s. NR 428.08(1)(a), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(9) The permittee shall submit quarterly reports per s. NR 428.09(1), (3) and (4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(9), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

Note 1: The IGCC auxiliary boiler is subject to NOx emission limits per s. NR 428.04(2)(a)2. and 3., Wis. Adm. Code and is 0.05 pounds per million Btu of heat input when firing natural gas and 0.09 pounds per million Btu of heat input when firing fuel oil. The BACT limit for NOx is more restrictive then the emission limit for NOx under s. NR 428,04, Wis. Adm. Code, thus the IGCC auxiliary boiler is expected to meet the emission limits for NOx under s. NR 428.04, Wis. Adm. Code.

LL. S44, B44 – IGCC Auxiliary Boiler

Pollutant: 5. Carbon Monoxide

a. Limitations: (1) The emissions may not exceed 0.045 pound per million Btu when firing natural gas based on a 30-day rolling average. (BACT); (2) The emissions may not exceed 0.045 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight based on a 30-day rolling average. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 factor or vendor provided emissions factor [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and /or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.5.a. (4). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Carbon Monoxide Emissions:</u> Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, Appendix A, US EPA Method 10, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(4), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.LL.5.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.LL.5.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

<table>
<tr><td colspan="2">LL. S44, B44 – IGCC Auxiliary Boiler</td></tr>
<tr><td colspan="2">Pollutant: 6. Volatile Organic Compounds (VOC)</td></tr>
<tr><td colspan="2">(a) Limitations: (1) The emissions may not exceed 0.0060 pound per million Btu when firing natural gas based on a 30-day rolling average. (LAER); (2) The emissions may not exceed 0.0020 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight based on a 30-day rolling average. (LAER); (3) The use of good combustion practices. (LAER); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 408.04, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor or vendor provided emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet LAER emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.6.a. (4). [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for VOC Emissions:</u> Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, US EPA Method 25 or 18, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(3), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.LL.6.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.LL.6.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]</td></tr>
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I.LL. S44, B44 – IGCC Auxiliary Boiler

Pollutant: 7. Lead Emissions

a. Limitations: (1) The emissions may not exceed 0.000000024 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.000009 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Lead Emissions: Whenever compliance emission testing is required, US EPA Method 12 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]
(2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code].	(2) The permittee shall keep records on the heat input used as required in condition I.LL.7.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]
(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]
(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.7.a. (4). [s. 285.65(3), Wis. Stats.]	(4) The permittee shall record information on the maintenance required in condition I.LL.7.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

LL. S44, B44 – IGCC Auxiliary Boiler

Pollutant: 8. Mercury Emissions

a. Limitations: (1) The emissions may not exceed 0.00000026 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.000003 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.8.a. (4). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Mercury Emissions:</u> Whenever compliance emission testing is required, US EPA Method 29 or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.LL.8.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.LL.8.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

LL. S44, B44 – IGCC Auxiliary Boiler

Pollutant: 9. Emissions of Fluorides

a. Limitations: (1) The emissions may not exceed 0.0000990 pound per million Btu when firing natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (2) The use of good combustion practices. (BACT); (3) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Emissions of Fluorides: Whenever compliance emission testing is required, US EPA Method 13B shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]
(2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]	(2) The permittee shall keep records on the heat input used as required in condition I.LL.9.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]
(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]
(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.9.a. (3). [s. 285.65(3), Wis. Stats.]	(4) The permittee shall record information on the maintenance required in condition I.LL.9.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

LL. S44, B44 – IGCC Auxiliary Boiler

Pollutant: 10. Visible Emissions

a. Limitations: 20% opacity or number 1 on the Ringlemann chart. [s. NR 431.05, Wis. Adm. Code, s. NR 440.207(4)(c), Wis. Adm. Code] See Note 1

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(1) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]
(2) The permittee shall conduct an initial test as required under s. NR 440.08, Wis. Adm. Code using the procedures and reference method in 40 CFR part 60, Appendix A, which is incorporated by reference in s. NR 440.17, Wis. Adm. Code. [s. NR 440.207(4)(c), Wis. Adm. Code]	(2) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

Note 1: Any gases emitted from the stack when the unit is fired with fuel oil shall not have an opacity greater than 20% (6 minutes average). The exception is one 6-minute period per hour when the opacity not exceeding 27%. The opacity standard does not apply during periods of start up and shut down or malfunction.

I.LL. S44, B44 – IGCC Auxiliary Boiler

Pollutant: 11. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.

a. Limitations: (1) The permittee shall use natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight and comply with the PM/PM10 limits to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall us natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight to comply with the case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with and meet the VOC LAER emission limits to comply with case by case MACT for organic HAPs and (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. 285.65(13), Wis. Stats.]

b. Compliance Demonstration:

(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet MACT emission limit. [s. 285.65(13), Wis. Stats.]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.11.a. (4). [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs: Whenever compliance emission testing is required a method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.LL.11.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.L.11.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 12. Sulfuric Acid Mist	
a. Limitations: (1) The emissions may not exceed 0.00024 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.00064 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption records, and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] 3) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.12.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Sulfur Acid Mist Emissions: Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] 2) The permittee shall keep records on the heat input used as required in condition I.LL.12.b.(3). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall keep records required under condition I.LL.3.b.(4) – (7) to demonstrate compliance with the sulfur content in the fuel. [s. NR 439.04(1)(d), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

MM. T16 – SCPC Boiler Fuel Oil Storage Tank (500,000 gallons), T118 – IGCC Fuel Oil Storage Tank (300,000 gallons), T121 – Diesel Gen. #1 Fuel Oil Storage Tank (5,000 gallons), T122 – Diesel Gen. #2 Fuel Oil Storage Tank (5,000 gallons), T123 - Fire Pump Fuel oil Storage Tank (1,000 gallon), T119, T120 – Two IGCC Sulfuric Acid Storage Tanks

The following emission limits apply to each storage tanks, T16, T118, T121, T122, T123.

Pollutant: 1. Volatile Organic Compounds (VOC)

a. Limitations: (1) Use of a carbon bed absorption system or its equivalent on each fuel oil storage tanks to meet LAER control requirements. (LAER); (2) 90% reduction in VOC emissions. (LAER) [s. NR 408.02, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Note 1

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the carbon bed; and (b) A list of items that will be checked and maintained and their frequency, to ensure that carbon bed is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (2) Compliance emission tests to demonstrate compliance with the 90% reduction emission limit in I.MM.1.a.(2) shall be conducted within 60 days after the start of the initial operation of tanks T16 and T118. [s. 285.65(3), Wis. Stats.] (3) The maximum true vapor pressure of fuel oil shall be less than 3.5 kPa. The condition is established so the storage tanks are not subject to NSPS requirements. [s. 285.65(7), Wis. Stats.] (4) The permittee may use available data on the Reid pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored fuel oil to determine the maximum true vapor pressure from the nomographs contained in API Publications 2517. [s. 285.65(7), Wis. Stats.]	(1) Reference test Method for Volatile Organic Compound Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 25 or 18 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(3)., Wis. Adm. Code] (2) The permittee shall record information on the maintenance required in condition I.MM.1.b.(1). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (3) The permittee shall retain records of the determined maximum true vapor pressure. [s, 285.65(7), Wis. Stats.]

Note 1: The standards of performance for a new sources under s. NR 440.285, Wis. Adm. Code apply to al new petroleum storage tanks which are larger than 40 cubic meters (10,600 gallons). Therefore, the new SCPC boiler and IGCC fuel oil storage tanks are subject to the requirements of s. NR 440.285. However the performance standards under this section apply to tanks storing organic liquids with a maximum true vapor pressure greater than 5.2 kPa (0.74 psia). The fuel oil has a maximum true vapor pressure of 0.035 kPa (0.005 psia). As a result, although the SCPC boiler and IGCC fuel oil storage tanks are subject to the performance standards under s. NR 440.285, Wis. Adm. Code there are no applicable NSPS standards for these tanks.

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY

Condition Type: 1. Construction Permit Requirements

a. Conditions:

(1) Construction Notification: The permittee shall inform the Wisconsin Department of Natural Resources, Southeast Region, 2300 North Dr. Martin Luther King Jr. Drive, Milwaukee, WI 53212, Phone (414) 263-8500, in writing of the following for the emissions unit covered in this permit:

(a) Notice of commencing construction shall be submitted within 15 days of the start of construction.

(b) Notice of intent to initially operate the source(s) covered by this permit, 30 days prior to the anticipated date of initial operation.

(c) Notice of the actual date of initial startutp shall be submitted within 15 days of the initial startup.

[s. NR 439.03(1), Wis. Adm. Code]

(2) (a) Construction Permit Expiration: This construction permit expires 90 months after the date of issuance. Construction or modification and an initial operation period for equipment shakedown, testing and Department evaluation of operation to assure conformity with the permit conditions is authorized for each emissions unit covered in this permit. Please note that the sources covered by this permit are required to meet all emission limits and conditions contained in the permit at all times, including during the initial operation period.
(b) Reevaluating BACT: The permittee shall submit information for reevaluating BACT to the Department at least 18 months prior to the commencement of construction of any permitted processes that may have not begun construction within eighteen months from the date of the issuance of the final permit. [ss. 285.60(1)(a)2 and 285.66(1), Wis. Stats.; s. NR 406.12, Wis. Adm. Code]

(3) Completion of Operation Permit Application :

(a) Compliance information required to complete the operation permit application for the emission units included in this permit should be tted to the DNR at least 4 months prior to the expiration of the Construction Permit.

(b) Operation of the source(s) covered by this permit after this permit expires is prohibited unless a complete operating permit application source(s) has been submitted to the Department.

[s. 285.60(1)(b)1., Wis. Stats.; s. NR 407.04(1)(b), Wis. Adm. Code]

(3) This permit supersedes permit #02-RV-054. [s. 285.65(3), Wis. Stats.]

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY

Condition Type: 2. Malfunction Prevention and Abatement Plans

a. Conditions:	**b. Compliance Demonstration:**
(1) A malfunction prevention and abatement plan shall be prepared and followed for the plant. [s. NR 439.11, Wis. Adm. Code] (2) A written copy of the plan shall be kept at the plant and shall be updated once every five years. [s. NR 439.11(1), Wis. Adm. Code] (3) All air pollution control equipment shall be operated and maintained in conformance with good engineering practices (i.e. operated and maintained according to manufacturer's specifications and directions) to minimize the possibility for the exceedance of any emission limitations [s. NR 439.11(4), Wis. Adm. Code]	(1) The plan shall be developed to prevent, detect and correct malfunctions or equipment failures which may cause any applicable emissions limitation to be violated or which may cause air pollution. [s. NR 439.11(1), Wis. Adm. Code] (2) This plan shall include installation, maintenance and routine calibration procedures for the control equipment instrumentation. This plan shall require an instrumentation calibration at the frequency specified by the manufacturer but not less than once per year plus an inspection and/or calibration whenever instrumentation anomalies are noted. [ss. NR 407.09(1)(c)1.c., NR 439.055(4) and s. NR 439.11, Wis. Adm. Code] (3) The plan shall require a copy of the operation and maintenance manual for the control equipment be maintained on site. The plan shall contain all of the elements in s. NR 439.11(1)(a) - (h), Wis. Adm. Code. [s. NR 439.11, Wis. Adm. Code] (4) The facility shall maintain an inventory of normal consumable items necessary to ensure operation of the control device(s) in conformance with the manufacturer's specifications and recommendations. [s. NR 439.11, Wis. Adm. Code] (5) The facility shall maintain records of the instrumentation calibrations. [s. NR 439.04, Wis. Adm. Code]

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY

Condition Type: 3. Stack Testing Requirements

a. Conditions:

(1) All testing shall be performed with the emissions unit operating at capacity or as close to capacity as practicable and in accordance with approved procedures. If operation at capacity is not feasible, the source shall operate at a capacity level, which is approved by the Department in writing. [s. NR 439.07(1), Wis. Adm. Code]

(2) If the testing for the sources is not completed in the time frame identified in this permit then the permittee shall request an extension upto 60 days to complete the testing. [s. 285.65(3), Wis. Stats.]

(2) The Department shall be informed at least 20 working days prior to any stack testing so a Department representative can witness the testing. At the time of notification a compliance emission test plan shall also be submitted to the Department for approval. When approved in writing, an equivalent test method may be substituted for the reference test method. [s. NR 439.07(2), Wis. Adm. Code]

(3) Two copies of the report on the tests shall be submitted to the Department for evaluation within 60 days following the tests. [s. NR 439.07(9), Wis. Adm. Code]

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY

Condition Type: 4. Acid Rain Requirements

a. Conditions:

(1) The permittee shall obtain and secure allowances equal to the actual annual SO2 emissions. (Allowances are available through the Chicago Board of Trade and other sources) [40 CFR Parts 72 and 75, s. NR 409.06(3), Wis. Adm. Code]

(2) The permittee shall have a Designated Representative (DR) in accordance with 40 CFR Part 72. The DR shall be responsible for submitting required permits, compliance plans and emission monitoring reports, allowance plans and compliance certifications; and will be the responsible official with regards to all matters under the acid rain program. [40 CFR Part 72 and 75, s. NR 409.07, Wis. Adm. Code]

(3) The permittee shall submit a Phase II acid rain permit to the Department at least 24 months before the date on which the unit commences operation. [s. 285.65(3), Wis. Stats., s. NR 409.08(1), Wis. Adm. Code]

(4) The owner or operator of a Phase I and phase II acid rain units shall install, calibrate, operate and maintain all monitoring equipment necessary for continuously monitoring sulfur dioxide, nitrogen oxides, carbon dioxide, stack flow rate and opacity. The type of monitoring equipment used and the manner and location of its installation are subject to prior department approval. [s. NR 439.095(1), Wis. Adm. Code]

(5) The owner or operator of monitoring equipment installed to comply with condition I.NN.4.a.(4) shall install, calibrate, maintain and operate the continuous emission monitor in accordance with the performance specifications in 40 CFR part 60, Appendix B or, for affected units, the performance specifications in 40 CFR part 75, Appendices A to I, incorporated by reference in s. NR 484.04(21) and (27), and the requirements in s. NR 439.09. The owner or operator of the source shall submit a quality control and quality assurance plan for approval by the department. The monitor shall follow the plan, as approved by the department. [s. NR 439.095(6), Wis. Adm. Code]

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY

Condition Type: 6. Acquisition of Emission offsets

a. Conditions:

(1) The permittee shall obtain Volatile Organic Compound offsets at a minimum ration or 1.3 or a total of 294 credit. [s. NR 408.06(4)(d), Wis. Adm. Code]

(2) The permittee will ensure that the actual transfer of credits has taken place prior to commencing operation of the power plant. [s. NR 405.06, Wis. Adm. Code]

(2) The permittee shall provide information on whether actual transfer of credits has occurred prior to commencing operation of the ERGS's project to the DNR, Bureau of Air Management, 101 S. Webster Street, P.O. Box 7921, Madison, WI 53707. [s. 285.65(3), Wis. Stats., s. NR 408.06, Wis. Adm. Code]

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY

Condition Type: 5. Compliance Reports / Records

a. Conditions:	**b. Compliance Demonstration:**
(1) Upon issuance of the operation permit, the permittee shall submit periodic monitoring reports. [s. NR 407.09(1)(c)3., Wis. Adm. Code] (2) Upon issuance of the operation permit, the permittee shall submit periodic certification of compliance. [s. NR 407.09(4)(a)3., Wis. Adm. Code] (3) The records required under this permit shall be retained for at least five(5) years and shall be made available to department personnel upon request during normal business hours. [s. NR 439.04, s. NR 439.05, Wis. Adm. Code]	(1) Submit a monitoring report, which contains the results of monitoring or a summary of monitoring results required by this permit to the Department every 6 months. (a) The time periods to be addressed by the submittal are January 1 to June 30 and July 1 to December 31. (b) The report shall be submitted to the Wisconsin Department of Natural Resources, Southeast Region, 2300 North Dr. Martin Luther King Jr. Drive, Milwaukee, WI 53212, Phone (414) 263-8500 within 30 days after the end of each reporting period. (c) All deviations from and violations of applicable requirements shall be clearly identified in the submittal. (d) Each submittal shall be certified by a responsible official as to the truth, accuracy and completeness of the report. (e) The content of the submittal is described in item D. of Part II of the operation permit. [s. NR 439.03(1)(b), Wis. Adm. Code] [s. NR 439.03(1)(b), Wis. Adm. Code] (2) Submit an annual, certification of compliance with the requirements of this permit to the Wisconsin Department of Natural Resources, Southeast Region, 2300 North Dr. Martin Luther King Jr. Drive, Milwaukee, WI 53212, Phone (414) 263-8500 and to Compliance Data - Wisconsin, Air and Radiation Division, U.S. EPA, 77 W. Jackson, Chicago, IL 60604]. (a) The time period to be addressed by the report is the January 1 to December 31 period which precedes the report. (b) The report shall be submitted to the Wisconsin Department of Natural Resources, Southeast Region, 2300 North Dr. Martin Luther King Jr. Drive, Milwaukee, WI 53212, Phone (414) 263-8500 and U.S. EPA within 30 days after the end of each reporting period. (c) The information included in the report shall comply with the requirements of Part II Section N of this permit. (d) Each report shall be certified by a responsible official as to the truth, accuracy and completeness of the report. [s. NR 439.03(1)(c), Wis. Adm. Code]

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