

INTERNAL USE ONLY

1

DO NOT DISTRIBUTE

June 5, 2008

Final Draft

**Technical Support Document for the
Advanced Notice of Proposed Rulemaking for
Greenhouse Gases;
Stationary Sources, Section VII.**

(73 FR XXXXX; June XX, 2008)

IN REFERENCE TO
THE REGULATION OF GREENHOUSE GASES FROM STATIONARY SOURCES
UNDER
THE CLEAN AIR ACT, AS AMENDED IN 1990

EPA Docket number: OAR-2008-yyyy
June 2008
U.S. Environmental Protection Agency
Office of Air and Radiation

Introduction

This technical support document (TSD) presents supporting information used by the United States Environmental Protection Agency (EPA) in the process of developing the Advance Notice of Proposed Rulemaking to regulate greenhouse gases in the United States. This TSD provides technical and other background information on the approaches, advantages, disadvantages, legal and policy questions presented in the ANPR. Some of the material appears in the ANPR, and is repeated here to bring clarity to this supporting document. Other information in the TSD was either too voluminous or detailed to be useful in the ANPR, but is presented here for interested parties to review and consider while preparing comments to the ANPR.

The text of this TSD follows the general outline of Section VII of the ANPR, but does not provide information under each item of section VII. Where supporting information is present, we have inserted explanatory text, or a reference to certain supporting documents, that can be found in the docket adjacent to this document. Where we have referenced other documents in this TSD, we have attempted to list the specific pages of interest in those documents to save the public time in locating the information relevant to the ANPR.

A condensed table of contents of section VII of the ANPR is:

VII: Stationary Source Authorities and Potential Options for Regulating Greenhouse Gases under the Clean Air Act**A. National Ambient Air Quality Standards (NAAQS)****B. Section 111 – New Source Performance Standards****C. Section 112 – National Emission Standards for Hazardous Air Pollutants****D. Preconstruction permits under the Prevention of Significant Deterioration Program****E. Title V Operating Permits Program****F. Market Based Mechanisms**

VII: Stationary Source Authorities and Potential Options for Regulating Greenhouse Gases under the Clean Air Act

A. National Ambient Air Quality Standards (NAAQS)

1. GHG-Relevant Documents from other Recent NAAQS Reviews

Through the authority of the CAA, EPA sets NAAQS for the protection of human health and the environment. In doing so, EPA examines a broad a deep body of scientific inquiry to support the appropriate level and form of each standard. In the process of reviewing the broad array of data and investigations that shed light on the question of whether and to what level to set the standard, EPA also encounters information on topics related to the standard in question. For example, in revising the ozone standard in 2008, EPA reviewed the results of thousands of studies on the impact of ozone on human health and the environment. Within that body of material, certain studies also yielded information useful to a discussion of the interaction between ozone, greenhouse gases, and climate change. Similar information has been obtained through studies on particulate matter, oxides of nitrogen, sulfur dioxide, and solar radiation.

Below is a brief list of documents that EPA considered in preparing the ANPR on greenhouse gas regulation, insomuch as the works contributed to our understanding of the tasks of regulating greenhouses gases, the benefits, and costs.

Oxides of Nitrogen and Sulfur

U.S. EPA Integrated Science Assessment for Oxides of Nitrogen and Sulfur – Environmental Criteria: First External Review Draft (December 2007).

EPA/600/R-07/145A

http://www.epa.gov/ttn/naaqs/standards/no2so2sec/cr_isi.html

Section 4.2.1.5 Aluminum Leaching, p. 4-16

Section 4.3.3.1.1 Forests, p. 4-122

Section 4.4.3, N₂O as a GHG and Interactions between Nitrogen Deposition and Biogenic N₂O Emissions, p. 4-176 to 4-179

Ozone

U.S. EPA. Air Quality Criteria for Ozone and Related Photochemical Oxidants, (February 2006). EPA 600/R-05/004aF.

http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html

Volume I, Chapter 10, Tropospheric Ozone Effects on UV-B Flux and Climate Change Processes, pp. 10-1 to 10-70

Volume III, Chapter 9, Annex on Environmental Effects, pp. AX9-5 to AX9-367

U.S. EPA Review of the National Ambient Air Quality Standards for Ozone: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper (January 2007), EPA-452/R-07-003
http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_sp.html

Chapter 7, Policy-Relevant Assessment of Welfare Effects, Evidence, pp. 466-543

Chapter 8, Staff Conclusions and Recommendations on the Secondary Ozone NAAQS, pp. 556-584.

U.S. EPA Final Ozone Regulatory Impact Analysis (March 2008)
<http://www.epa.gov/ttn/ecas/ria.html#ria2007>

Chapter 6: Incremental Benefits of Attaining Alternative Ozone Standards Relative to the Current 8-hour Standard (0.08 ppm), pp. 21-22.

Particulate Matter

U.S. EPA. Air Quality Criteria for Particulate Matter (October 2004). U.S. Environmental Protection Agency, Washington, DC, EPA 600/P-99/002aF-bF, 2004. http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_2006_cd.html

Volume I, Chapter 4, Environmental Effects of Airborne Particulate Matter, pp. 4-1 to 4-240.

Volume II, Chapter 9, Section 9.3.3, Relationships between Atmospheric PM and Climate Change Processes, pp. 9-111 to 9-112.

U.S. EPA. Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper (December 2005). EPA-452/R-05-005a.
http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_2006_sp.html

Chapter 6, Section 6.5: Effects on Climate Change and Solar Radiation, pp. 6-53 to 6-58

Chapter 7, Section 7.4.3: Climate Change and Solar Radiation, p.7-17.

U.S. EPA. Final PM NAAQS Regulatory Impact Analysis (October 2006).
<http://www.epa.gov/ttn/ecas/ria.html>

Chapter 5, Table 5-2: Human Health and Welfare Effects of Pollutants Controlled to Simulate Attainment with PM_{2.5} Standards, p. 5-5.

2. Additional Information Regarding NAAQS Implementation Requirements

Section VII of the ANPR provides a brief outline of a number of requirements for implementing a NAAQS. In this section (below), EPA provides more detail on the specific requirements for implementing a NAAQS established by the CAA.

a. State Implementation Plans

(i) Section 110(a)(2)

The list below identifies the program elements that must be addressed in SIPs from section 110(a)(2) of the Clean Air Act:

- Emissions limits and other control measures: Section 110(a)(2)(A) requires states in general, through the SIP, to establish enforceable emissions limits and other control measures necessary to meet the requirements of the Act.
- Ambient air quality monitoring/data system: Section 110(a)(2)(B) requires states to set up and operate ambient air quality monitors, collect and analyze NAAQS-related air quality data and make these data available to EPA upon request.
- Program for enforcement of control measures: Section 110(a)(2)(C) requires states to establish a program to enforce control measures required under subparagraph (A) and to provide for regulation of new/modified sources (new source permit program).
- Interstate transport: Section 110(a)(2)(D) requires states to control emissions from sources, or other emissions producing activities, that contribute significantly to nonattainment or interfere with maintenance of a NAAQSs in another state or that interfere with measures required to prevent significant deterioration of air quality or to protect visibility in another state.
- Adequate resources: Section 110(a)(2)(E) requires states to provide adequate funding, personnel and legal authority to implement their SIPs and assurances that the State retains authority to ensure implementation where it relies on local or regional governments.
- Stationary source monitoring system: Section 110(a)(2)(F) requires states to establish a system to monitor emissions from stationary sources and to submit periodic emissions reports to EPA.
- Emergency power: Section 110(a)(2)(G) requires states to have authority to implement emergency episode plans in their SIPs to prevent elevated air pollution levels that pose an imminent and substantial danger to public health, welfare, or the environment.
- Ability to revise SIPs due to NAAQS changes or inadequacy findings: Section 110(a)(2)(H) requires states to revise their SIPs in response to changes in the NAAQS, availability of improved methods for attaining the NAAQS, or in response to an EPA finding that the SIP is inadequate.

DO NOT DISTRIBUTE

June 5, 2008

Final Draft

- Provisions for meeting part D: Section 110(a)(2)(I) requires areas designated as nonattainment to meet the applicable nonattainment planning requirements of part D, title I of the CAA.
- Consultation with local and Federal government officials during SIP development: Section 110(a)(2)(J) requires states to meet applicable local and Federal government consultation requirements of CAA section 121.
- Public notification of NAAQS exceedances: Section 110(a)(2)(J) requires states to notify the public when a NAAQS is violated pursuant to the specific requirements of CAA section 127.
- PSD and visibility protection: Section 110(a)(2)(J) also requires states to adopt programs for attainment areas that prevent significant deterioration and protect visibility pursuant to the specific requirements of CAA title I part C.
- Air quality modeling/data: Section 110(a)(2)(K) requires states to perform air quality modeling for predicting effects on air quality of emissions from any NAAQS pollutant and submission of modeling data to EPA upon request.
- Permitting fees: Section 110(a)(2)(L) requires the state to collect from each major stationary source a permitting fee to cover the cost of reviewing, approving, implementing and enforcing required operating permits.
- Consultation/participation by affected local government: Section 110(a)(2)(M) requires States to consult with and allow participation by local political subdivisions affected by the SIP.

(ii) Nonattainment area requirements

EPA has provided interpretive rules and guidance on fulfilling SIP requirements in 40 CFR Part 51 (Requirements for Preparation, Adoption, and Submittal of Implementation Plans). The following subsections outline in more detail the nature of each required nonattainment area plan element.

(1) RACM/RACT for Nonattainment Areas

States must adopt RACM (including RACT) to address emissions from sources contributing to nonattainment. For detailed information on these requirements, please refer to the recent implementation rules: Final Rule to Implement the 8-hour Ozone NAAQS, 70 FR 71612, 71659 (11/29/05); Clean Air Fine Particle Implementation Rule, 72 FR 20586, 20609 (4/25/07).

(2) Demonstration of Attainment for Nonattainment Areas

The SIPs for nonattainment areas should provide for the implementation of control measures on relevant stationary and mobile sources to demonstrate attainment of the NAAQS as expeditiously as practicable, but no later than the applicable statutory attainment date for the area. Therefore, if a state adopts less than all available measures in an area, but adequately demonstrates that reasonable further progress (RFP) and

attainment of the NAAQS are assured, then such measures are not required (44 FR 20375 (April 4, 1979) and 56 FR 5460 (February 11, 1991)). The EPA has taken the position that it would be unreasonable to require a plan that demonstrates attainment to include all technologically and economically available control measures even though such measures would not expedite attainment. Thus, for some sources in areas that demonstrate attainment, it is possible that some available control measures may not be “reasonably” available because implementing them would not expedite attainment.

Attainment is generally demonstrated in the SIP by modeling future air quality using EPA-approved air quality models. The SIP regulations found at 40 CFR 51.112(a)(1) require states to demonstrate the adequacy of adopted SIP control measures to demonstrate attainment “by means of applicable air quality models, data bases, and other requirements specified in appendix W (Guideline on Air Quality Models).” This guideline indicates the types and historical records for data that EPA deems necessary for modeling demonstrations (e.g., use of on-site meteorological stations; 12 months of data are required to demonstrate attainment for the affected area). In the context of a GHG NAAQS it is unclear how individual states would demonstrate, through modeling, the adequacy of an attainment plan due to the global nature of GHGs. If a GHG NAAQS is established, EPA would need to review available modeling platforms and issue additional guidance to states on how to meet this requirement.

(3) Reasonable Further Progress (RFP)

Part D SIPs must provide for RFP (see section 172(c)(2) of the CAA). Section 171 of the CAA defines RFP as “such annual incremental reductions in emissions of the relevant air pollutant as are required by part D, or may reasonably be required by the Administrator for the purpose of ensuring attainment of the applicable NAAQS by the applicable attainment date.” Historically, for some pollutants, RFP has been met by showing annual incremental emission reductions generally sufficient to maintain linear progress toward attainment by the applicable attainment date.

EPA has historically interpreted that the RFP requirement for nonattainment areas should be met, at least in part, by “adherence to an ambitious compliance schedule” which is expected to periodically yield significant emission reductions, and as appropriate, linear progress. CITE Under this interpretation it would be appropriate to expect early implementation of less technology-intensive control measures (e.g., work practice standards), and to phase in more technology-intensive control measures (e.g., installation of new hardware). Failure to implement the SIP provisions required to meet annual incremental reductions in emissions (i.e., RFP) in a particular area could result in the application of sanctions as described in sections 110(m) and 179(b) of the CAA (pursuant to a finding under section 179(a)(4)), and trigger the contingency measures required by section 172(c)(9) of the CAA.

(4) Contingency Measures

Section 172(c)(9) of the CAA defines contingency measures as measures in a SIP that are to be implemented if an area fails to make RFP, or fails to attain the NAAQS by the applicable attainment date. Contingency measures should consist of available control measures that are not already included in the primary control strategy for the affected area.

Contingency measures must be designed to become effective without further action by the state or the Administrator, upon determination by EPA that the area has failed to meet reasonable further progress obligations, or to attain the NAAQS by the applicable attainment date. The EPA interprets this requirement to mean that no further rulemaking actions by the state, or EPA, would be needed to implement the contingency measures (see generally 57 FR 12512 and 13543-13544). Therefore, states must show that contingency measures can be implemented with minimal further action on their part and with no additional rulemaking actions, such as public hearings or legislative review. If EPA determines that a nonattainment area has failed to meet RFP or timely attain the NAAQS, EPA generally expects states to take necessary actions to implement contingency measures within 60 days after EPA notifies the state of such failure.

(5) New Source Review (NSR) Program Requirements

The NSR programs contained in parts C and D of title I of the CAA govern preconstruction review and permitting for any new or modified major stationary sources of air pollutants regulated under the CAA as well as any precursors to the formation of that pollutant when identified for regulation by the Administrator. If EPA establishes a NAAQS for GHGs, the CAA requires each state to implement a NSR program for each identified pollutant.

The NSR program is composed of three different permit programs: Prevention of Significant Deterioration (PSD); Nonattainment NSR (NA NSR); and Minor NSR. The PSD program and NA NSR program are often referred to as the Major NSR program because these programs apply only to major sources. EPA rules addressing the Major NSR program can be found at 40 CFR 51.165, 51.166, 52.21, 52.24, and part 51, appendix S. The Minor NSR program requirements can be found at 40 CFR 51.160-164.

The PSD program applies when a major source located in an area that is designated as attainment or unclassifiable for any criteria pollutant, is constructed or undergoes a major modification. The NA NSR program applies when a major source located in an area that is designated as nonattainment for any criteria pollutant, is constructed or undergoes a major modification. The Minor NSR program covers both major and minor sources that undergo construction or modification activities that do not qualify as major, and it applies regardless of the designation of the area in which a source is located.

The PSD requirements include but are not limited to the following: installation of Best Available Control Technology (BACT); air quality monitoring and modeling analyses to ensure that a project's emissions will not cause or contribute to a violation of any NAAQS or maximum allowable pollutant increase (PSD increment); notification of the Federal Land Manager of nearby Class I areas; and public comment on the proposed permit.

Areas designated as nonattainment for a NAAQS must implement the requirements of nonattainment NSR in their SIPs within 3 years of designation. Nonattainment NSR requirements include but are not limited to: installation of Lowest Achievable Emissions Rate (LAER) control technology; offsetting new emissions with creditable emissions reductions; certification that all major sources owned and operated in the state by the same owner are in compliance with all applicable requirements under the CAA; an alternative citing analysis demonstrating that the benefits of proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification; and public comment on the proposed permit.

Minor NSR programs must meet the statutory requirements in section 110(a)(2)(C) of the CAA. Minor NSR program requirements are more general, and require regulation of the modification and construction of any stationary source as necessary to assure that the standards are achieved. This provides significant discretion to each state on how to implement Minor NSR. One potential drawback of this approach is a certain level of inconsistency from state to state in both permitting procedures and resulting permit requirements on similar sources.

(6) Emissions Inventories

The FY-08 Omnibus Appropriations Bill required "the Agency to use its existing authority under the Clean Air Act to develop and publish a rule requiring mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy." This rule is currently being developed.

EPA also plans to issue a rule entitled Air Emissions Reporting Requirements (AERR) in summer 2008. This rule is likely to change some aspects of EPA's emissions inventory reporting requirements. States already voluntarily submit data about hazardous air pollutants to EPA. EPA will explore ways to use the voluntarily-submitted data to inform the development of the U.S. annual GHG emission inventory. Prepared annually by EPA, in cooperation with other agencies, the national GHG inventory report presents time-series data on U.S. GHG emissions and GHG sinks and fulfills the U.S. emissions reporting obligations under the U.N. Framework Convention on Climate Change.

(7) General Conformity

The general conformity rule establishes procedural requirements Federal agencies must follow when they plan to take an action affecting emissions of all NAAQS-related pollutants in both nonattainment and maintenance areas. Federal actions affecting emissions in attainment areas are not subject to general conformity determinations, but may be subject to other applicable attainment area requirements. General conformity applies one year following the promulgation of designations for any new or revised NAAQS. Section 176(c) of the CAA, as amended (42 U.S.C. 7401 et seq.), requires that all Federal actions conform to an applicable implementation plan developed pursuant to section 110 and part D of the CAA. The general conformity rule contains criteria and procedures for demonstrating and assuring conformity of Federal actions to a SIP. Each Federal agency must determine that any actions covered by the general conformity rule conform to the applicable SIP before the action is taken.

For the purpose of summarizing the general conformity rule, the three major parts are described here: applicability, procedure, and analysis. The general conformity rule applies to Federal actions that cause direct and indirect emissions of criteria pollutants or their precursors, are reasonably foreseeable, and can practicably be controlled by the Federal agency through its continuing program responsibility. Certain Federal actions are exempt from general conformity, including: actions covered by the transportation conformity rule; actions with emissions impacts below specified *de minimis* levels; and certain other actions that are either specifically listed as exempt or predetermined to conform. The general conformity rule also establishes procedural review requirements. Federal agencies must make their conformity determinations available for public review. Notice of draft and final general conformity determinations must be provided directly to air quality regulatory agencies and to the public by publication in a local newspaper. In making a general conformity determination, a federal entity must analyze the impacts of direct and indirect emissions of a planned Federal action. The general conformity rule provides several options that will satisfy the analysis of air quality criteria. The analysis must also demonstrate that the Federal action meets any applicable SIP requirements and emissions milestones. If EPA establishes a GHG NAAQS, EPA would need to develop protocols or guidance on how GHG pollutants would be evaluated under a general conformity review.

(8) Transportation Conformity

Transportation conformity is required under CAA section 176(c) (42 U.S.C. 7506(c)) to ensure that federally supported highway and transit project activities are consistent with (“conform to”) the purpose of the SIP. Transportation conformity applies in areas that are designated nonattainment, and those areas redesignated to attainment after 1990 (“maintenance areas” with plans developed under CAA section 175A) for the following transportation-related criteria pollutants: ozone, particulate matter (PM-2.5 and PM-10), carbon monoxide (CO), and nitrogen dioxide (NO₂). Conformity to the

purpose of the SIP for transportation activities means they will not cause new air quality violations, worsen existing violations, or delay timely attainment of the relevant NAAQS (or “standards”). If EPA establishes a GHG NAAQS, EPA would need to review the contribution of transportation-related projects and associate mobile source emissions to the relevant GHG pollutants, and develop rules and guidance on the application of transportation conformity to the GHG NAAQS.

B. Section 111 – New Source Performance Standards

In this section, we discuss approaches to greenhouse gas control for certain sectors that may be among the largest stationary sources of GHG emissions in the United States. This discussion is illustrative, not exhaustive. We included this information in the TSD to give the public an idea of some possible technical approaches. Before deciding to use any specific approach to control GHG under section 111 of the CAA, the Agency would evaluate the approach further to ensure that it meets the requirements of section 111.

We have delved into some detail in examining these sectors of the economy. We elected to do this in the context of an ANPR, because an ANPR can facilitate discussion between the Agency and stakeholders on a very wide range of issues. Without this technical discussion, our audience would not have basic information about EPA’s thinking in approaching GHG control in key sectors. We aim to provide information regarding the types of controls and general scale of reductions that we believe are potentially available in the near term. The discussion of sector-specific strategies are based on information currently available to the Agency—information gathered, for example, through reviews of pollution reduction options for other pollutants or through voluntary GHG reduction programs. We intend for the information in this section of the TSD to provide enough of a picture of Agency thinking to allow the public to answer the questions raised in the ANPR in enough detail to be useful to stakeholders and for the Agency.

In some places in the discussion, we discuss actions that might be characterized as work practices, which are an option available to the Agency under section 111 of the Act, but only in certain circumstances. We recognize that section 111(h) limits the circumstances under which EPA can establish work practice standards for a particular source category. Specifically, section 111(h) provides that a “design, equipment, work practice or operational standard” may be promulgated if the Administrator determines that “(A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations.” We note that EPA has not yet evaluated whether the 111(h) criteria are satisfied for the source categories discussed in

this TSD. We would only propose work practice standards for a category consistent with the requirements of section 111(h). Also, we note that the description of a particular regulatory option as a work practice in this TSD does not represent the Agency's final determination that such a method of control, in fact, qualifies as a work practice standard within the meaning of section 111.

We have identified some approaches that are work practices because they create operational and process efficiencies that can reduce emissions, but may not capture or control emissions in a way that is readily comparable to a standard. As discussed above, section 111 permits exclusive reliance on these types of practices only when a standard of performance is not feasible or enforceable because quantification against a standard is technically problematic. These situations happen most often where the relevant emissions are fugitive emissions, which are difficult to control and measure. We believe that these practices represent some of the more effective actions that can be taken in the near-term for certain sources, either exclusively or in combination with controls on emission points, a final reason for their discussion in this document.

Section 111 also requires standards to be applied to categories of sources and provide different mechanisms for regulating new and existing sources. As explained in the ANPR, section 111 requires EPA to regulate emissions from categories of stationary sources. EPA has already established NSPS for over 70 categories and subcategories of stationary sources; however EPA could also create new categories and/or reorganize the existing source categories for purposes of GHG regulation. Some of the regulatory options discussed below might be possible only if EPA opts to take such action. As also explained in the ANPR, EPA has authority to set standards for new and modified sources under section 111(b) and for existing sources under section 111(d). Specifically, where EPA establishes an NSPS standard for a pollutant, a 111(d) standard is required for existing sources in the regulated source category except in two circumstances. First, 111(d) prohibits regulation of a NAAQS pollutant. Second, "where a source category is being regulated under section 112, a section 111(d) standard of performance cannot be established to address any HAP listed under 112(b) that may be emitted from that particular source category."¹

A reevaluation of our options for regulating GHG from stationary sources may also point to a multipollutant strategy. This is because a single industrial facility may be composed of a number of different processes or points and may emit a variety of different pollutants, making it helpful to examine from a facility-wide perspective in order to better understand the total contributions of emissions from a particular facility. Doing so may also permit the examination and development of facility-wide or industry-wide compliance strategies which provide greater flexibility to achieve overall emission

¹ See 70 Fed. Reg. 15994, 16029-32 (Mar. 29, 2005).

reduction targets, such as emissions averaging or cap-and-trade approaches. As noted above, in developing such approaches we would also need to be mindful of the specific requirements of section 111. Moreover, we believe that it may be beneficial to consider these facility or sector-wide approaches when designing control requirements on a “multi-pollutant” basis, as recommended by the National Academies of Science to address the full range of pollutants emitted by these facilities.²

a. Boilers – Industrial Boilers

i. Greenhouse gas emissions from Industrial Boilers

An industrial boiler is a combustion device that combusts any fuel to produce steam or to heat water or any other heat transfer medium. The term “industrial boilers” generally includes commercial boilers and institutional boilers and, thus, are used in virtually every economic sector. Industrial boilers are used in manufacturing, processing, mining, refining, and any other industry. Commercial/institutional boilers are used in commercial establishments (e.g., stores/malls and laundries), medical centers, educational facilities, etc. Currently, there are approximately 45,000 industrial boilers in the United States, with heat input capacities greater than 10 million Btu per hour, combusting approximately 500 million barrels of oil per year, 68 million tons of coal per year, and 27,000 million cubic feet of natural gas per day.³ In addition, industrial boilers combust about 169 million tons of biomass per year. Greenhouse gases, predominantly CO₂, have been estimated to be approximately 1,250 million metric tons per year of CO₂e, accounting for approximately 20 percent of the total US GHG inventory. GHG emissions are expected to increase in the future as the energy demand increases.

ii. GHG Control Measures

Reductions in emissions of GHG from industrial boilers would most likely occur from thermal efficiency improvement, process improvements to reduce steam and electricity usage, and biomass firing/co-firing. With the thermal efficiency or process improvements in a boiler or at an industrial, commercial, or institutional facility, less fuel would be burned to generate the same output, leading to direct reductions in GHG emissions. Biomass can substitute for fossil fuels in some types of boilers, resulting in lower life cycle GHG emissions. All options may also affect emissions of other air pollutants. There are numerous demonstrated efficiency improvements that exist,

² The National Academy of Sciences’ Committee on Air Quality Management in the United States; *Air Quality Management in the United States* (2004) “Strive to take an integrated multipollutant approach to controlling emissions of pollutants posing the most significant risks.”

³ These estimates are subject to change, as EPA is currently evaluating them in light of the decision in *NRDC v. EPA*, No. 04-1385 (D.C. Cir., June 8, 2007), which requires EPA to subject those facilities which burn solid waste to standards for solid waste incinerators under section 129, rather than standards for boilers under section 112.

including boiler and steam system optimization, heat exchanger fouling mitigation and optimization, efficiency improvements in process heaters and motors, waste gas and power recovery, and process optimization and process technology improvements. These measures, as applied to individual facilities can result in energy savings and greenhouse gas reductions on the order to 1 to 10 percent, depending on the site's current operating practices. These practices generally result in cost savings over time as well as reductions in criteria pollutants.

Measures can be grouped according to how they could be implemented as part of a GHG reduction rule. One category of measures, such as waste gas recovery, is also associated with reductions of criteria pollutants. The installation of a system to recover, and route to a boiler, gases that would routinely be flared reduces the overall amount of fossil fuel that is burned in a boiler, and this in turn results in net criteria pollutant and GHG reductions. Energy efficiency measures such as boiler and steam system optimization, heat exchanger fouling mitigation and optimization will result in energy savings and small reductions in criteria pollutant emissions as less fuel is burned. Finally, converting a steam generating boiler to a combined heat and power generation unit is a measure that results in significant efficiency improvements with strong benefits and short payback.

iii. Interaction with Other Rules

EPA recently amended the new source performance standards (NSPS) for both electric utility, and industrial-commercial-institutional boilers (subparts Da, Db and Dc). We conducted a technology review of the emission standards for particulate matter, sulfur dioxide, and nitrogen oxides and concluded that the standards for these criteria pollutants should be revised. During the public comment period on the proposed revisions, we received several comments urging EPA to develop additional standards to address GHG emissions from these source categories. Court challenges to EPA's decision not to regulate GHG from these source categories were remanded back to the Agency in September 2007 in light of the Supreme Court's decision in Massachusetts v. EPA.

iv. Options for regulating GHG under Section 111

There appear to be several approaches for structuring greenhouse gas reduction requirements for industrial boilers under the NSPS. One approach would be to establish certain work practices or equipment standards that would address GHG. Examples are work practice standards for minimizing excess air or exhaust temperatures (to improve boiler efficiency), or equipment standards for installation of economizer and air pre-heaters. In most cases, this approach would not require extensive or complete GHG characterization because compliance could be easily demonstrated without it. A second approach would be to adopt numerical efficiency standards for boilers. A third approach would allow facilities to demonstrate that they have achieved reductions of GHG through

decreased fuel usage per unit output. This approach may have some disadvantages in that the compliance demonstration might favor facilities that could show dramatic increases in efficiency over others who had made improvements prior to implementation of the rule. A fourth approach could include a requirement for substituting biomass for fossil fuels in some types of boilers. Various combinations of these approaches could also be considered. Significant potential GHG reductions are available from existing as well as new sources. As discussed above, section 111 uses different mechanisms for regulating new and modified versus existing sources and establishes when such standards are required. Promulgating regulations for both new and existing sources would get significantly more reductions than regulations on new sources alone since the growth rate for new boilers is low.

To help inform the possible use of NSPS to control GHG from industrial boilers, we would need to consider how to develop a metric for measuring and benchmarking boiler GHG emissions in terms of the facility's output production (e.g., amount of GHG per unit of production for a given facility). This metric would be useful in understanding trends relative to GHG efficiencies per type of facility, and setting numerical facility or process-specific efficiency targets under this NSPS. This metric might also be useful in allocating allowances in potential future cap-and-trade programs. However, given the range of industrial producers, there are challenges in establishing such output metrics in some sectors.

b. Boilers - Electric Power Sector

i. GHG emissions from the Electric Power Sector

The electric power sector contributes about 34 percent of U.S. GHG emissions, all but a small fraction as CO₂, amounting to approximately 2.4 billion metric tons CO₂e annually.⁴ This sector includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

U.S. electric power sector GHG emissions are produced by about 3,500 steam boiler, combined cycle, and combustion turbine power plants with a total net electric generating capacity of 740 GW. These fuel combusting plants represent 77 percent of the generating capacity of the electric power sector, and produce 70 percent of the net electricity supplied to the U.S. grid. This electrical energy is derived from the combustion of fossil fuels: coal (71%), natural gas (27%), petroleum (2%), with a fractional percent from renewable fuels.⁵

⁴ Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 –2005

⁵ DOE Energy Information Agency: Annual Energy Outlook, 2008

Natural gas and petroleum produce less GHG than coal per unit of heat content, and while there are a large number of peaking units (simple cycle units) in the power sector, most of the natural gas is burned in combined cycle plants that are significantly more efficient than the average coal plant. The percentages of GHG emissions from natural gas and petroleum are therefore actually less than their percentage shares of electrical output, while coal's share of GHG emissions is even greater. In the electric power sector, GHG control measures (e.g. efficiency improvements, etc) will likely be focused on coal plants.

However, for the industry sector, the predominance of natural gas is fired in boilers, not turbines. Therefore, the efficiency of industrial boilers and of simple cycle units producing energy should be explored for improvements in GHG emissions reductions from the industrial energy sector.

ii. GHG Control Measures

Net heat rate (Btu's of fuel energy used to produce 1 kWh of net electrical energy output) is the performance metric that most directly correlates with GHG emissions from fossil fueled power plants. Reducing (improving) the net heat rate for any fossil plant by 1 percent reduces its fuel consumption by 1 percent, thereby reducing its GHG emissions by 1 percent -- for the same net electrical output.

Efficiency can be improved at existing units, and new units can be built that produce at higher efficiencies. At existing plants, a range of physical options offer thermal efficiency improvements that would either reduce the plant heat rate to a level somewhat below (i.e. more efficient) the original design value, or restore a degraded heat rate to the original design value. For steam boiler plants the range of options typically includes optimizing the performance of any of the feed water, boiler, turbine-generator, condenser, heat rejection, and auxiliary systems, improving control systems, installing higher efficiency pumps, fans, and drives, and reducing the moisture content of solid fuels. These options are well known in the industry, but for many reasons are not equally feasible from plant to plant or from unit to unit in a plant. Combined cycle and simple cycle combustion turbine plants have fewer physical options for significant efficiency improvement. All fossil plants might reduce heat rate to some extent through plant-specific best operating and maintenance practices that support consistent operation at the optimal thermodynamic efficiency for any load.

Net heat rates in the existing coal plant fleet range from less than 9000 Btu/kWh to over 15,000 Btu/kWh, depending on age, size, fuel type, and a host of other plant-specific factors. The coal fleet average is about 10,300 Btu/kWh. EPA's preliminary internal analysis indicates that individual coal plant heat rates might be reduced by as much as 4 percent to 9 percent through efficiency improvements, depending on the unit classification. A reasonable expectation for individual plants would be a 2 to 5 percent reduction, considering site-specific constraints. More analysis is needed to consider costs

and estimate a reasonable expectation for the average fleet-wide heat rate reduction, but it will likely be less than 5 percent.

In the future, construction of new high efficiency fossil fuel power plants and retirement of the oldest, least efficient fossil plants present additional opportunities to gradually reduce the average fossil fleet heat rate. For example, a new fully-proven supercritical coal plant design with a net efficiency of 40 percent (about 8500 Btu/kWh) can operate at a heat rate 18 percent below the current coal fleet average. A future ultra-supercritical plant design with an efficiency of perhaps 43 percent would have a heat rate 23 percent below the current coal fleet average, and therefore produce 23 percent less GHG than the average existing coal plant. The discussion of supercritical and ultra-supercritical designs is not intended to convey that EPA would require that all new plants adopt those designs. Rather we are offering the observation to demonstrate that these new options optimize energy efficiency and show technological advancements beyond the traditional conventional pulverized coal units. Further, as new plants are built using supercritical and ultra-supercritical technologies, the emission data obtained from them will be the basis for revised standards in the future, providing an incentive for other new installations to use the technology.

In addition to heat rate improvements, biomass co-firing can substitute for some of the coal in most types of existing and future coal-fired boilers, resulting in proportionately lower GHG emissions. However, at an existing large coal plant there will typically be a complex of physical, operational, and biomass supply constraints that limit biomass substitution for an average facility to 10 percent or less of the heat input to one boiler. Regional and seasonal biomass supply constraints will likely further limit the use of co-firing for both existing and future coal plants. As a pragmatic order-of-magnitude estimate, biomass co-firing might eventually substitute for 2 percent to 5 percent of coal used in the current coal fleet.⁶

EPA recently amended the new source performance standards (NSPS) for both electric utility, and industrial-commercial-institutional boilers (subparts Da, Db and Dc). We conducted a technology review of the emission standards for particulate matter, sulfur dioxide, and nitrogen oxides and concluded that the standards for these criteria pollutants should be revised. During the public comment period on the proposed revisions, we received several comments urging EPA to develop additional standards to address GHG emissions from these source categories. Specifically, commenters argued that CO₂ and other GHG are reasonably anticipated to endanger public health or welfare and thus EPA must set NSPS for greenhouse gases emitted from these sources. Commenters also presented numerous options for reducing CO₂ emissions including: requiring use of IGCC technologies, developing a trading program CO₂ cap-and-trade program for existing sources, and establishing minimum thermal efficiency levels. Court challenges to EPA's decision not to regulate GHGs from these source categories were

⁶ Biomass Cofiring Update 2002, EPRI 1004319, Final Report, July 2003.

remanded back to the Agency in September 2007 in light of the Supreme Court's decision in Massachusetts v. EPA.

iv. Options for regulating GHG

There appear to be several approaches for structuring GHG reduction requirements for utility boilers under the NSPS. One approach would be to establish certain work practices or equipment standards that would address GHG. Examples are work practice standards for minimizing excess air or exhaust temperatures (to improve boiler efficiency), or equipment standards for installation of economizer and air pre-heaters. In most cases, this approach would not require extensive or complete GHG characterization because compliance could be easily demonstrated without it. A second approach would be to establish numerical efficiency standards for boilers. A third approach might include a requirement for substituting biomass for fossil fuels in some types of boilers, resulting in lower GHG emissions.

To help inform the possible use of NSPS to control GHG from utility boilers, we would need to consider how to develop a metric for measuring and benchmarking boiler GHG emissions in terms of the unit's output production (e.g., amount of GHG per unit of electricity for a given unit). This metric would be useful in understanding trends relative to GHG efficiencies per type of facility, and setting numerical facility or process-specific efficiency targets under this NSPS. This metric might also be useful in setting up allocation/allowance systems in potential future cap and trade programs.

c. Refineries

i. GHG emissions from the Petroleum Refining Industry

The petroleum refining industry in the U.S. is the largest in the world, accounting for over twenty percent of the world's refining capacity and with connections to virtually every economic sector, including the transportation sector and the chemical industry. Currently, there are approximately 150 refineries in the United States with a refining capacity of approximately 17 million barrels of oil per day. Greenhouse gases, predominantly CO₂ but also methane and nitrous oxide, account for approximately 200 million metric tons per year of CO₂ equivalent (CO₂ eq), comprising approximately one quarter of all GHG emissions from stationary industrial sources (excluding utilities) and approximately 3 % of the total US GHG inventory. The majority of GHG emissions in this sector (70%) are from the burning of fuels used for onsite heat and steam. Another 25 percent are related to burning coke off of catalyst during the fluid catalytic cracker catalyst regeneration process. Finally, the remaining 5 percent of GHG emissions are associated with miscellaneous vents and evaporative losses of methane. GHG emissions

are expected to increase in the future as the energy intensity of refining increases to accommodate an ever increasing share of heavy and sour crude.⁷

ii. GHG Control Measures

We believe that reductions in emissions of GHG from refineries in the near term would most likely occur from energy and process efficiency improvements, and there appear to be numerous efficiency improvements that currently exist and have been adequately demonstrated. These include boiler and steam system optimization, heat exchanger fouling mitigation and optimization, efficiency improvements in process heaters and motors, waste gas and power recovery, and process optimization and process technology improvements. These measures, as applied to individual plants may result in energy savings and greenhouse gas reductions on the order to 1 to 10 percent, depending on the site's current operating practices and the refinery's processing configuration. These practices have generally been shown to result in cost savings over time.

Measures can be grouped according to how they could be implemented as part of a GHG reduction rule. One category of measures, such as waste gas recovery, is also associated with reductions of criteria pollutants. The installation of compressor systems for recovering gases that would routinely be flared can reduce the overall amount of fuel that is burned at a refinery, and this in turn results in net criteria pollutant reductions at the refinery. A related gas recovery measure is the depressurization of delayed cokers to a recovery system, rather than to the atmosphere. This measure can not only offset fuel losses, but it also can limit direct emissions of GHG and VOC to the atmosphere. Both these measures have been promulgated in some form as best demonstrated technology under the newly promulgated NSPS Subpart Ja.

Energy efficiency measures such as boiler and steam system optimization, heat exchanger fouling mitigation and optimization, and process heater efficiency improvements also will result in energy savings and small reductions in criteria pollutant emissions as refiners burn less fuel to operate their processes. Energy efficiency measures such as the application of variable speed motors for variable load applications, such as pumps, also results in energy savings, but these savings generally would occur outside of the refinery at the electric generating utility, so there may not be corresponding on-site criteria pollutant reductions.

There are also a number of process technology improvements and process-specific optimization measures that we believe to be available that can improve the efficiency of the refining process. These measures include improved energy efficiency of distillation by application of progressive crude distillation, installation of power recovery turbines on the offgas of the FCCU regenerator, and optimization of the hydrogen plant.

⁷ Source: RTI. Draft Refinery Profile; June 2007. Prepared for the Office of Atmospheric Programs, OAP.

Because they are process-specific, the appropriate application of these technologies will depend on the facility's current operating configuration.

Finally, combined heat and power generation (CHP) is a measure that results in significant efficiency improvements with strong benefits and short payback. We estimate that 60% of installed refinery capacity has CHP in form or another at this time.⁸

iii. Interaction with Other Rules

The new source performance standards (NSPS) for Petroleum Refineries, first promulgated in 1978 as 40 CFR 60 Subpart J were recently amended and a technology review conducted that resulted in the promulgation of new Subpart Ja. These performance standards include emission limitations and work practice standards for fluid catalytic cracking units, fluid coking units, delayed coking units, fuel gas combustion devices, and sulfur recovery plants. As such, they regulate criteria pollutant emissions from the processes that are also responsible for most of the refinery GHG emissions. During the public comment period for Subpart Ja, we received several comments in favor of developing new source performance standards to address GHG emissions from refineries. However, we declined to adopt standards for GHG emissions in that rulemaking, in part because while doing so was within our discretion, we believed that it was important to fully consider the implications for programs under other parts of the CAA before electing to regulate GHG under section 111.

iv. Options for regulating GHG under Section 111

There appear to be several potential approaches for structuring GHG reduction requirements for refineries under the NSPS. One approach would be to establish certain work practices, equipment standards, and numerical efficiency standards for affected sources within refineries that would address GHG. Examples include the flare gas recovery and delayed coker depressurization work practice standards that are required under Subpart Ja, or equipment standards for variable speed motors and combustion air preheater designs for process heaters. Although this approach would more be prescriptive than a performance standard, in most cases it would not require extensive or complete GHG characterization because compliance could be easily demonstrated without it. A second approach would be to establish numerical efficiency standards for affected sources. A third approach would be to provide refiners the flexibility to make improvements within their facilities and demonstrate that they have achieved reductions through GHG tracking and reporting. This type of approach would be better suited to capture measures that are typically applied refinery-wide such as boiler and steam system optimization, and heat exchanger fouling mitigation and optimization. Unless specifically addressed in any resulting standard, this approach may have some disadvantages in that

⁸ Source is the DOE CHP inventory (www.eea-inc.com/chpdata).

the compliance demonstration might favor refiners that could show dramatic increases in efficiency over others who had made improvements prior to implementation of the rule.

A third approach might include some combination of the first two approaches. In order to adopt a rate-based NSPS standard to limit GHG from refineries, we would first need to develop a metric for measuring and benchmarking the relationship between refinery GHG emissions to production of the many refinery outputs. We are aware of proprietary metrics that exist that are used by refiners to benchmark their operations with respect to GHG emissions; however the use of a proprietary metric is problematic from a rulemaking perspective. We believe that a more transparent metric is desirable that could be used to describe the amount of GHG per unit of production for a given refinery. This metric would be useful in understanding trends relative to GHG efficiencies per type of refinery or crude slate characteristics, and setting numerical refinery or process-specific refinery efficiency targets under this NSPS. This metric might also be useful in setting up allocation/allowance systems in potential future cap and trade programs.

Based on our work in developing options that also generate GHG benefits under NSPS Subpart Ja, one specific approach could be to promulgate under section 111(d) requirements similar to the existing NSPS requirements but focused on reducing GHG emissions for all existing sources of GHG in the source category. Specifically, the Subpart Ja flare gas recovery requirements and delayed coker depressurization requirements are expected to generate GHG reductions on the order of 200,000 tons CO₂e per year, or approximately 0.1 percent of the refinery baseline. Adopting a standard incorporating these reductions into a GHG performance standard and extending the requirements to existing sources could increase potential GHG reductions by as much as a factor of 10, to over 1 percent of the baseline. Costs for the flare gas recovery option are negative over the life of the equipment, and simple payback appears to be approximately 2 years at 7 percent interest for most installations.

d. Portland Cement

i. GHG Emissions from the Cement Manufacturing Industry

After China and India, the U.S. is the world's third largest cement producer with clinker production occurring in approximately 107 facilities located in 36 States and Puerto Rico. Cement is produced by combining limestone with silica, alumina, and iron; grinding the mixture into a powder; and heating the mixture in a high temperature kiln to produce clinker. The clinker is then combined with gypsum (and sometimes other additives) and ground to produce cement. In the high-temperature kiln, the calcium carbonate in the limestone is calcined to produce calcium oxide and liberates carbon dioxide (CO₂). Additional CO₂ is generated in the kiln from the combustion of fuels (such as coal).

The cement industry contributes approximately 5 percent to all industrial CO₂ emissions in the U.S. (equivalent to approximately 2 percent of total U.S. CO₂ emissions). Emission estimates in 2005 from fossil fuel combustion and non-combustion activity in the U.S. cement industry accounted for 81.4 million metric tons of CO₂ equivalent (CO₂e). Between 1990 and 2005, U.S. process-related emissions (resulting from the calcination of limestone) increased 38 percent, from 33.3 million metric tons CO₂ eq to 45.9 million metric tons CO₂ eq.⁹ Combustion-related emissions from the U.S. cement industry were estimated at approximately 35.5 million metric tons CO₂ e in 2005. A small amount of off-site emissions (0.1 million metric tons CO₂ e) occur as a result of electricity use.

ii. GHG Control Measures

Significant work has already been performed in developing inventories of GHG, energy benchmarking, and reviews of energy efficiency and other measures to reduce CO₂ emissions. These include:

- CO₂ Accounting and Reporting Standard for the Cement Industry.¹⁰
- CO₂ emissions profile of the U.S. Cement Industry available at <http://www.epa.gov/ttn/chief/conference/ei13/ghg/hanle.pdf>
- EPA ENERGY STAR's Energy Efficiency Improvement and Cost Saving Opportunities for Cement Making, a guide which examines the energy savings potential for existing practices and technologies in cement plants. (Available at www.energystar.gov/industry, see Industries in Focus.)
- EPA ENERGY STAR's cement plant energy performance indicator (EPI), a web-based tool on the ENERGY STAR website that enables the benchmarking of the energy efficiency of individual cement plants in the United States. Plants receive a percentile rating from 1 – 100. (www.energystar.gov/industry, see Industries in Focus) .
- A study by the Ernest Orlando Lawrence Berkeley National Laboratory for EPA and the Department of Energy: Energy Efficiency and Carbon Dioxide Emissions Reduction Opportunities in the U.S. Cement Industry. (Available at <http://www.climatevision.gov/sectors/cement/pdfs/44182.pdf>.)

In addition, EPA's Office of Research and Development has funded a study of air pollution controls and efficiency measures for cement kilns.¹¹ This study includes techniques to reduce CO₂ emissions, an evaluation of the emission reductions they

⁹ National estimates of process-related emissions are calculated based on methodologies developed by the Intergovernmental Panel on Climate Change (IPCC).

¹⁰ CO₂ Accounting and Reporting Standard for the Cement Industry. World Business Council for Sustainable Development, June 2005. Version 2.0

¹¹ Air Pollution Controls and Efficiency Improvements for Cement Kilns. Prepared for U.S. Environmental Protection Agency, Air Pollution and Control Division, Research Triangle Park, NC. Final Report. March 31, 2008

achieve, and estimates of their costs. The Portland Cement Association is also conducting an independent study that is a detailed review of CO₂ control technology. These reports are in draft stage and are currently under internal review.

Reductions in emissions of GHG from cement plants would most likely occur from fuel efficiency and electric energy efficiency measures as well as raw material and product changes that reduce the amount of CO₂ generated per ton of cement produced. There are numerous efficiency measures generally accepted by much of the U.S. industry, and many of these measures have been adopted in recent cement plant improvements. In addition, the most modern cement plants have incorporated these measures in their capacity replacements and expansion projects. Such measures may directly reduce GHG emissions by cement plants, or they may indirectly reduce GHG emissions at sources of power generation due to reducing electrical energy requirements (and thus purchased electricity). Some examples of measures for GHG emission reductions include:

- Replacing existing wet kilns (and perhaps dry kilns) with more energy efficient preheater/precalciner kilns.
- Improving heat recovery and preheating.
- Reducing the amount of cement kiln dust wasted. Cement kiln dust includes material that has already been calcined, so wasting it increases the total amount of raw materials that must be calcined per unit of product.
- Implementing improved process control and management systems.
- Using more biomass or non-fossil fuels.
- Adding alternative sources of calcium, such as steel slag as a limestone substitute. This material has already been calcined so process emissions are reduced.
- Reducing the ratio of clinker to cement. This reduces that amount of clinker required per unit of cement. Clinker production is the step that produces almost all of the CO₂ emissions.

iii. Interaction with Other Rules

The New Sources Performance Standards for Portland cement kilns were first promulgated in 1971 as 40 CFR 60 Subpart F and were reviewed and revised in 1974 and 1988. The NSPS establishes performance standards for particulate matter and opacity for cement kilns and clinker coolers. It also includes an opacity limit for certain other operations. We are currently reviewing the NSPS and on May 30, 2008, we proposed amendments with emission limits for particulate matter, nitrogen oxides, sulfur dioxide, and volatile organic compounds.

iv. Options for Regulating GHG under Section 111

We are aware of several possible approaches for structuring GHG reduction requirements for cement facilities under the NSPS, including various types of numerical

performance standards and equipment/work practices. Performance can be measured in units such as tons of CO₂/ton of feed, clinker production, or cement production.

One regulatory approach could be to establish performance standards for each type of kiln based on performance test data for CO₂. This approach could consider appropriate subcategories that take into account inherent differences in process design and operation that inevitably affect the amount of CO₂ generated. For example, preheater/precalciner kilns are more energy efficient than are dry kilns, and both are more energy efficient than the older kilns using the wet process. Consequently, three subcategories of kilns might be appropriate for existing sources. Alternatively, technology-forcing emission limits might be applied to existing facilities to encourage the replacement or retirement of the older and less energy efficient kilns. Standards for new sources could be based on the most efficient of the kiln designs.

It might be possible to develop a performance standard to provide flexibility, such as emissions averaging across multiple kilns at a plant or across multiple plants within a company. This approach might also accommodate a sector-wide cap-and-trade program. One of the potential drawbacks is that it might be difficult to identify and account for all of the site-specific factors that might affect CO₂ emissions, and it would be difficult to be confident that a given performance standard can reasonably be met by all kilns using the techniques that are available for reducing CO₂ emissions. The emission limits in the performance standard could be structured to favor newer facilities or those who have already made investments to improve efficiency, and it could put pressure on older, unoptimized facilities to upgrade or rebuild processes. This approach might also accelerate the adoption of some of the new technologies discussed above.

Another concept that could possibly be included in the performance standard approach would be to encourage and allow credits or offsets for overall energy efficiency improvements that result in reductions of indirect emissions of CO₂ (e.g., reduction in electricity consumption). For example, facilities could receive credits toward reductions of their direct emissions (i.e., emissions from the processes at the facility) by implementing measures they demonstrate result in less purchased electricity. These “credits” might be subtracted from the direct emissions when determining compliance with the performance standard.

Another possible regulatory approach that we might be able to consider would be to require that all plants achieve a specific reduction in GHG emissions, either on a facility-wide or company-wide basis. Such an approach might provide flexibility for each owner or operator to identify the most cost effective techniques to implement to achieve the reductions. We question whether this approach might favor the poor performers that have not optimized operations, while would penalize those who have already implemented improvements or installed new processes.

Equipment and work practice standards are another type of regulatory approach that we have used in certain situations in the development of national emission standards, when the criteria of section 111(h) are satisfied. This approach would identify cost-effective measures that are reasonable for all or most facilities to implement, and then mandate the adoption of these measures for specific types of kilns or specific types of operations. Alternative measures would be permitted if they were shown to provide equivalent or greater reductions. This mandated technology approach could be structured to consider the feasibility and cost of implementing them at specific sites. Reduction measures would be implemented at a specific site when they met certain criteria, such as cost effectiveness or payback time.

Another approach would be a standard expressed in terms of fuel efficiency rather than CO₂ based on the consideration that the liberation of CO₂ from limestone during calcination is inevitable, but improvements in fuel efficiency have been demonstrated to reduce CO₂ emissions from combustion. A fuel efficiency standard could be expressed in terms of million BTU consumed (or some other unit of measure for the fuel) per ton of clinker produced.

We could also consider developing a menu of preferred regulatory approaches based on analyzing and evaluating those described above and their variations, such as different levels of required performance and their associated costs. For example, EPA is developing a model of the cement industry that is capable of analyzing multiple control strategies for multiple pollutants and considers many site-specific factors affecting the economics, such as the type of kiln, capacity, location, site-specific cost of control, etc. This tool is designed with the objective of minimizing the cost of production and emission control over the time horizon of interest, subject to the demand for commodities and satisfying any emissions cap while utilizing emissions trading.

An issue requiring resolution will involve applicability of the rule requirements. We must determine what facilities should be covered under the NSPS—what size thresholds (if any) should be used; if any entities be explicitly exempted; and how new sources and sources that shut down should be treated in terms of coverage under the program and allocations as part of a cap and trade. We will also have to consider whether to allow offsets to enhance the coverage of the program and to increase compliance flexibility. In addition, we will need to explore necessary standards and protocols to ensure the integrity of any flexibility provisions. We must analyze the magnitude of expected industry growth and of potential reductions from existing facilities, to assess the impact a cap may have on growth.

e. Iron and Steel

i. GHG emissions from the Iron and Steel Industry

The iron and steel industry in the U.S. is the third largest in the world (after

China and Japan), accounting for about 8 percent of the world's raw iron and steel capacity and supplying several industrial sectors, such as construction (building and bridge skeletons and supports), vehicle bodies, appliances, tools, and heavy equipment. Currently, there are 18 integrated iron and steel mills that make iron from iron ore and coke in a blast furnace and refine the molten iron (and some ferrous scrap) in a basic oxygen furnace (BOF) to make steel. In addition, there are approximately 93 electric arc furnace (EAF) steel mills ("minimills") that produce steel primarily from recycled ferrous scrap. In 2006, integrated mills produced 43 million metric ton of raw steel and minimills produced 56 million metric tons.

Greenhouse gas emissions from the sector are predominantly CO₂ and a small amount of methane. EPA estimates that approximately 71 million metric tons are emitted per year¹² of CO₂eq, accounting for about 9 percent of all GHG emissions from stationary industrial sources (excluding utilities) and 1 percent of the total U.S. GHG inventory. Most of the GHG emissions are emitted from coal use. Specifically, coal is thermally distilled to produce coke for ironmaking and coke oven gas for fuel, and greenhouse gases are emitted through the combustion of the resulting process gases (blast furnace gas and coke oven gas). The subsequent steelmaking process reduces the carbon content of iron to make steel in the basic oxygen process. In the EAF process, carbon electrodes are consumed during the melting and refining ferrous scrap. The carbon removed in the steelmaking furnaces is emitted primarily as CO₂.

ii. GHG Control Measures

Given that coal is both an energy source and a material input to the steel making process, steel production is inherently a greenhouse gas-emitting process. Acknowledging this, the steel industry worldwide has voluntarily invested in material and energy efficiency projects that have resulted in reducing greenhouse gas emissions.

Process emissions of greenhouse gases from the production of coke, iron, and steel (defined to include CO₂ emissions from the production and use of metallurgical coke) have declined by over 40 percent since 1990 due to the increased use of ferrous scrap, restructuring of the industry, and technological improvements in both processes.¹

One option to reduce GHG emissions from the iron and steel sector was studied by the Lawrence Berkeley National Laboratory.¹³ This report identified approximately

¹² From EPA's *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2006* (48.6 million metric tons from the production of coke, iron, and steel) and from EPA's *Quantifying Greenhouse Gas Emissions from Key Industrial Sectors in the U.S.* (22 million metric tons from fossil fuel combustion).

¹³ Worrell, E., N. Martin and L. Price. 1999. "Energy Efficiency and Carbon Dioxide Emissions Reduction Opportunities in the U.S. Iron and Steel Sector." Report No. LBNL-41724. Ernest Orlando

50 techniques, including demonstrated and emerging technologies, which provide increased energy efficiency and reduced process emissions of CO₂.

Examples of process improvements include coal injection into the blast furnace, which reduces emissions from coke production; improved recovery and increased beneficial use of process gases, which reduces the consumption of natural gas; reducing natural gas usage by more efficient ladle preheating; improved process controls for the blast furnace, BOF, coke underfiring, and sinter plant; and waste heat recovery. Several opportunities were identified to improve energy efficiency and reduce electricity consumption, which results in reductions of indirect GHG emissions. Examples include variable speed drives for motors, energy monitoring and management systems, reducing air leakage, programmed heating, and ultra high power transformers. The report also identified two integrated steel plants in the U.S. that used low-cost waste fuels (previously vented to the atmosphere) to power steam turbines for cogeneration units.

Other changes in technology that may have been implemented at some plants and demonstrated to reduce GHG emissions include the direct current EAF, which reduces carbon consumption and electricity requirements include scrap preheating using the hot EAF offgas; thin slab casting, which reduces the use of natural gas in reheat furnaces and electricity consumption in rolling mills; recuperative burners in reheat furnaces; continuous casting, which has almost eliminated the previous technique of casting into ingots and subsequently reheating in soaking pits and rolling in roughing mills; recuperators for the blast furnace's hot blast stoves; using waste heat to dry coal before it is charged into the coke oven; and new ironmaking technologies (such as direct reduced iron), which eliminate the need for coke plants and blast furnaces.

EPA is interested in reviewing pertinent information regarding the capital costs, operating costs, emission reductions achieved, and payback times for these various techniques. We acknowledge in advance that the data will vary widely and depend on many site-specific factors. EPA's consideration of how best to approach the sector will consider the broad issues of reduction of GHG emissions, primary energy savings, and the rate and period of the return on investment in greenhouse gas abatement strategies.

iii. Interaction with Other Rules

The new source performance standards for BOFs, first promulgated in 1977 as 40 CFR 60 subpart N, were amended and a technology review conducted that resulted in the promulgation of subpart Na in 1986. These performance standards include equipment standards and emission limitations for particulate matter (PM) and opacity from BOF shops. The NSPS for EAFs, first promulgated in 1975 as 40 CFR 60 subpart AA, were amended in 1983 with the promulgation of subpart AAa. These performance standards

include emission limitations for PM and opacity from EAF shops and argon-oxygen decarburization. These NSPS regulate some of the sources of GHG emissions; however, the standards have no direct effect on GHG emissions.

Maximum Achievable Control Technology (MACT) standards were promulgated for coke oven batteries in 1993 in 40 CFR 63, subpart L. These standards addressed emissions for charging coal into the oven; leaks from doors, lids, offtakes, and collecting mains; and the bypassing (venting to the atmosphere) of raw coke oven gas. A technology review of the MACT standard and a residual risk assessment for certain types of coke oven batteries were conducted and resulted in amendments to the MACT standard in 2005. Although the MACT standard and amendment focused on reductions in emissions of hazardous air pollutants, they also resulted in the reduction of methane emissions (one of the primary constituents of coke oven gas) from coke oven batteries. Methane emissions from leaks at coke oven batteries have been reduced significantly over the past several years as the result of state regulations, consent decrees, and the MACT standard, which reduced the number and size (i.e., mass emission rate) of leaks from the coking process.

iv. Options for Regulating GHG under Section 111

There are several general approaches for structuring GHG reduction requirements for iron and steel facilities under section 111. One approach would be to establish performance standards for each type of process and for appropriate subcategories that take into account inherent differences in process design and operation that inevitably affect the amount of CO₂ generated. The most significant emission points of greenhouse gases at iron and steel plants are amenable to direct measurement of CO₂ emissions, and production rates can be determined with reasonable accuracy. Consequently, performance can be measured in units such as lb CO₂/ton of production. For a process-specific approach, performance standards might be expressed as lb CO₂/ton of coke for the coke battery's combustion stack, lb CO₂/ton of iron for the blast furnace stoves, and lb CO₂/ton of steel for BOF and EAF steelmaking. For fossil fuel combustion in other operations such as reheat furnaces, annealing furnaces, boilers, etc., performance standards might be expressed in terms of fuel or energy consumption rather than production.

Another general approach would be to develop a facility-wide performance standard, such as lb CO₂/ton of steel based on the combined CO₂ emissions from all sources at the facility.¹⁴ Such an approach would provide the owner or operator more flexibility in determining which process units or combustion sources are the most cost effective candidates for CO₂ emission reductions. This approach is an efficiency standard that would favor newer facilities or those who have already made investments to improve

¹⁴ Such an approach may require that we redefine the affected facility through rulemaking.

efficiency, and it would create incentives for older facilities that are not optimized, to upgrade or rebuild processes. This approach might also accelerate the adoption of some of the new technologies discussed above.

Another concept that we might be able to include in either of the two performance standard approaches would be to encourage and allow credits or offsets for overall energy efficiency improvements that result in reductions of indirect emissions of CO₂ (e.g., reduction in electricity consumption). For example, facilities could receive credits toward reductions of their direct emissions (i.e., emissions from the processes at the facility) by implementing measures they demonstrate result in less purchased energy for EAFs, rolling mills, etc. These “credits” might be subtracted from the direct emissions when determining compliance with the performance standard.

Equipment and work practice standards are another type of regulatory approach that we have used in certain situations in the development of national emission standards, when the criteria of section 111(h) are satisfied. This approach would identify cost effective measures that are reasonable for all or most facilities to implement, and then mandate the adoption of these measures for specific processes. Alternative measures could be permitted if they were shown to provide equivalent or greater reductions.

A final option that we might be able to consider is an intra-sector trading program, where facilities operating in the sector would be allowed to trade emissions credits to meet a performance standard, or an industry-wide cap.

f. Petroleum Production and Natural Gas Systems

i. GHG emissions

Petroleum production and natural gas systems cover operations involving the extraction of oil and natural gas at production wells as well as processing, transmission and storage, and distribution of natural gas. As of 2005, there were approximately 700 thousand oil and natural gas production wells in the United States producing approximately 1.8 billion barrels of oil and 19 trillion cubic feet of natural gas annually. Greenhouse gases, predominantly methane, but also including CO₂ and nitrous oxide, have been estimated to be approximately 168 million metric tons per year of CO₂ equivalent (CO₂ eq), accounting for approximately 28 percent of the CO₂ eq produced by non-fossil fuel combustion in the US and approximately 3 percent of the total US GHG inventory.

Methane (CH₄) emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include, but are not limited to: natural gas engines and turbine uncombusted exhaust, bleed and discharge emissions from

pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. CH₄ emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, CH₄ emissions are released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion.

The emissions from the oil and natural gas sector can be broken out into a few categories. Approximately 38 percent of all GHG emissions from the oil and natural gas sector are estimated to occur at oil and natural gas production facilities. Those emissions are predominantly CH₄. Yet an even a greater percentage of emissions from the sector, 45 percent, are emitted at natural gas processing, transmission and storage, and distribution operations. Those emissions are also predominantly CH₄. The remaining GHG from this source category are emissions from natural gas flaring at oil production facilities (4 percent of total GHG) and acid gas removal units (13 percent) at natural gas processing plants.

ii. GHG Control Measures

Measures addressing emissions of methane, rather than combustion-related CO₂, would be of greatest benefit for this sector. Reductions in emissions of GHG from petroleum and natural gas systems could occur in a variety of ways including a more broadly applied leak detection and repair (LDAR) programs, development of industry practice or management standards, and/or equipment replacement (e.g., replacing high-bleed pneumatic controllers with low-bleed devices or compressor engine seals).

For example, LDAR practices encompassing methane could be applied at facilities that now must apply LDAR in order to meet VOC standards. Technology-based reduction efforts could include mandating a switch from high to low-bleed or instrument air driven pneumatic devices and use of vapor recovery on oil and condensate storage tanks and vented emissions from dehydrators. Best practices/performance standards could include utilization of “green” well completion and well workover practices, more frequent replacement of compressor rod packing and improved compressor station blowdown methods.

Through EPA’s Natural Gas STAR Program, a voluntary public-private partnership with the oil and gas industry, many of these technologies and management practices have been well documented (including information on cost, benefits and reduction potential) and implemented in oil and gas systems throughout the U.S. Through the partnership, the industry has eliminated more than 577 billion cubic feet (Bcf) of methane emissions through the implementation of more than 120 cost-effective technologies and practices. In 2006, Natural Gas STAR partners reported emissions reductions of approximately 85.9 Bcf. These emission reductions also have cross-cutting

benefits for domestic energy supply, industrial efficiency, greenhouse gas emission reductions, and improvements in local air quality through associated criteria and hazardous pollutant emission reductions.

iii. Interaction with Other Rules

The new source performance standards (NSPS) for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants were promulgated in 1985 as 40 CFR 60 Subpart KKK. These performance standards include work practice standards for equipment (i.e., pumps, valves, fittings, compressors) to monitor and minimize leaks of VOC from the areas within the natural gas processing plant. This equipment is also responsible for most of the methane emissions at these facilities.

iv. Options for regulating GHG under Section 111

An approach for structuring methane reduction requirements for petroleum and natural gas systems under the NSPS would be to establish certain work practices and equipment standards for affected sources within petroleum production and natural gas system facilities that would address GHG emissions. This approach would work for measures that could be described in terms of a work practice or equipment standard, and could be used only if the 111(h) criteria are met. As discussed above, examples are the leak detection and repair program that is required in NSPS Subpart KKK, or an equipment standard for pneumatic devices to replace high-bleed controllers with low-bleed units. Although this approach would be prescriptive in most cases, it would not require extensive or complete GHG characterization because compliance could be easily demonstrated without it.

Finally, it may be possible to develop additional requirements for leak detection and repair, equipment standards and operational practices under NSPS 111(b) and (d) to apply to sources both upstream (petroleum and natural gas production facilities) and downstream (natural gas transmission, storage and distribution systems). The requirements would most likely be similar to any applied to sources in the NSPS KKK source category since the sources of GHG emissions are predominately the same.

g. Landfills

i. GHG emissions from the MSW Landfill Industry

Landfills are the largest anthropogenic source of methane in the United States (approximately 24 percent of total US anthropogenic methane in 2006). There are approximately 1,800 operational landfills in the United States, with the largest landfills receiving most of the waste and generating the majority of the methane. Landfill

emissions constitute 1.8 percent of all GHG emissions in the United States.¹⁵ After placement in a landfill, organic waste (such as paper, food waste, and yard trimmings) is decomposed by anaerobic bacteria producing stabilized organic materials and landfill gas. Landfill gas is comprised of approximately 50 percent methane, 50 percent carbon dioxide, and trace amounts of nonmethane organic compounds (NMOC). Significant landfill gas production typically begins one or two years after waste disposal in a landfill and can continue for 10 to 60 years or longer.

Methane emissions from landfills are a function of several factors, including: (1) the total amount of waste in MSW landfills, which is related to total waste landfilled annually; (2) the characteristics of landfills receiving waste (i.e., composition of waste-in-place, size, climate); (3) the amount of CH₄ that is recovered and either flared or used for energy purposes; and (4) the amount of CH₄ oxidized in landfills instead of being released into the atmosphere. The estimated annual quantity of waste placed in MSW landfills increased from about 209 MMT in 1990 to 307 MMT in 2006, an increase of 47 percent. During this period, the estimated CH₄ recovered and combusted from MSW landfills increased as well. In 1990, for example, approximately 888 Gg of CH₄ were recovered and combusted (i.e., used for energy or flared) from landfills, while in 2006, 5,958 Gg CH₄ was combusted. In 2006, an estimated 26 new landfill gas-to-energy (LFGTE) projects and 41 new flares began operation, resulting in a 4.4 percent increase in the quantity of CH₄ recovered and combusted from 2005 levels.

National estimates of solid waste emissions are calculated based on methodologies developed by the Intergovernmental Panel on Climate Change (IPCC). Between 1990 and 2006, net CH₄ emissions from U.S. landfills decreased 16 percent, from 149.6 MMTCO_{2e} to 125.7 MMTCO_{2e}. This downward trend in overall emissions results from increased quantities of landfill gas being collected and combusted, which offsets the additional CH₄ emissions that result from increased amounts of MSW sent to landfills.

ii. GHG Control Measures

Landfills install a gas collection system and combust landfill gas using flares or energy recovery devices such as boilers, reciprocating engines, and microturbines. Landfill gas is classified as a medium Btu gas (heating value of 350 to 600 Btu per cubic foot) and can be used as an energy source for the creation of electricity, heat, or alternate fuels such as pipeline quality gas or vehicle fuel. This practice affords an environmental benefit by significantly reducing emissions of methane, CO₂, SO₂, NO_x, and other pollutants resulting from fossil fuel combustion.

¹⁵ Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005, EPA, 2007, p. 97.

Since 1994, EPA has been promoting the use of landfill gas as a renewable, green energy source through the Landfill Methane Outreach Program (LMOP). The Program has assisted in the development of approximately 360 LFG utilization projects - including 30 new projects and 20 project expansions that went online in 2007. To date, approximately 445 landfill gas (LFG) energy projects were operational in the United States. These 445 projects generate approximately 11 billion kilowatt-hours of electricity per year and deliver 236 million cubic feet per day of LFG to direct-use applications. EPA estimates that approximately 535 additional landfills present attractive opportunities for project development.

iii. Interaction with Other Rules

Rules currently affecting MSW landfills include new source performance standards, emission guidelines, and MACT standards under CAA sections 111(b), 111(d), and 112. These rules require large landfills to estimate their non-methane organic compound (NMOC) emissions and install and operate gas collection systems when these emissions exceed a threshold. To ensure proper collection system operation and fugitive emissions reduction, these landfills are required to collect gas from all landfill areas, conduct monthly monitoring at each gas collection well, and monitor surface methane emissions. The collected landfill gas must be flared, combusted in an enclosed combustion device which may include energy recovery, or treated prior to energy recovery. These requirements ensure essentially 100 percent conversion of collected methane to CO₂ and reduce CO₂ emissions where energy recovery is used to displace other sources of energy.

iv. Options for Regulating GHG under the Section 111

(1) MSW Landfills without LFG Collection and Control Systems

Current section 111(b) NSPS and section 111(d) emission guidelines require a landfill with a design capacity greater than 2.5 million megagrams (Mg) to run models to determine if and when a 50 Mg/year NMOC emissions threshold will be reached. Once reached, this threshold triggers a series of compliance dates that require construction and operation of a LFG collection and control system (GCCS) within 30 months. Options for regulating and reducing methane emissions from sites without a GCCS include the following: requiring a shorter time period for GCCS Design Plan preparation and installation, requiring smaller sites to comply with NSPS regulations (based on waste in place, not site capacity), and requiring a methane emissions threshold for GCCS installation and operation that would bring in additional landfills beyond those regulated by the current 50 Mg NMOC threshold. Landfills subject to section 111 regulations are allotted one year after reporting NMOC emissions exceeding 50 Mg to produce a GCCS Design Plan and an additional 18 months for installation. EPA estimates that the timetable could be decreased to 6 months for the GCCS Design Plan and 15 months for

GCCS installation without placing significant burden on the landfill owner/operators. This would shorten the maximum time between the date that a site reports exceeding an emissions threshold and the date that a GCCS starts up from 30 months to 21 months and could result in methane emissions reductions. Another option could be to require landfill operators to anticipate the date they will exceed 50 Mg and to require the design and construction to be finished by the time the threshold is exceeded.

Landfills with a design capacity less than 2.5 million Mg are not required to comply with section 111 regulations. One option for treatment of such facilities would be to create a waste-in-place trigger for NSPS regulations that could replace or be additional to the existing design capacity trigger. Since methane emissions are dependent on waste in place, not the design capacity, a waste in place threshold would lessen unnecessary compliance by low methane emitters and increase regulatory requirements for sites with higher emissions. For example, a site with a large unused capacity may be required to do NSPS reporting for many years before exceeding the 50 Mg NMOC threshold and triggering the GCCS requirements, particularly if disposal rates and the amount of waste in place are low. On the other hand, a site may escape NSPS regulation by having a design capacity below the 2.5 million Mg threshold, but LFG emissions may be relatively high if disposal rates are high and the amount of waste in place is approaching the design capacity.

Using standard AP-42¹⁶ emission factors, we can estimate methane emissions for a reference case. For example, a landfill generating 50 Mg of NMOC would also produce 787.6 scfm of methane, or approximately 8,400 metric tons of methane emissions. That volume of methane has a CO₂e value of 176,460 tons. Our analysis indicates that reduction of the emissions trigger would result in earlier GCCS installation and reduced methane emissions from landfills.

There are also a large number of closed landfills (approximately 8000) that are not currently subject to section 111 regulations as well as a significant number of smaller landfills that do not meet the applicability criteria for control under the existing suite of regulations. As such, the applicability of current standards could be revised to include closed landfills that are not currently controlled and smaller active landfills (based on waste in place or design capacity).

(2) MSW Landfills with Gas Collection and Control Systems

¹⁶ U.S Environmental Protection Agency (1998) Compilation of Air Pollutant Emission Factors: Volume I: Stationary Point and Area Sources, AP-42, Volume 1: *Stationary Point and Area Sources, 5th ed.*, Supplement E, Chapter 2.4: Municipal Solid Waste Landfills, Office of Air Quality Planning and standards, Research Triangle Park, NC, November 1998, <http://www.epa.gov/ttn/chief/ap42/ch02/final/ch02s04.pdf>

NSPS requires that landfills install new wells and collect LFG from areas where waste has been in place for five years in active cells or two years in cells that are closed or at final grade. At sites with large active areas this results in waste being disposed up to five years before LFG is collected. At large sites with high disposal rates, cells may be completed in less than five years. Requiring earlier installation of GCCS systems could result in significant methane emissions.

To reduce GHG emissions by capturing and controlling landfill gas emissions that are uncontrolled by the current rule, we could shorten this time between waste placement and gas collection. An example would be shortening the time allowed to install new wells to 3 years for active cells and one year for closed cells or even requiring horizontal wells as waste is placed in all waste areas and requiring collection to begin within one year of waste placement, the generally accepted time frame for the onset of anaerobic decomposition. Alternatively, the accelerated well installation schedule can be triggered on a tons disposed basis (e.g., wells need to be installed in recently deposited waste that amounts to more than 500,000 tons). Another approach would be to base the accelerated GCCS expansion requirements on an emissions threshold. The site can determine if it has exceeded the emissions threshold by running EPA's Landfill Gas Emissions Model (LandGEM) for the amount of waste without wells yet installed.

(3) Other Control Options

The current suite of regulations encourages energy recovery, but only requires control of LFG, which can be accomplished through open and closed flaring systems. Another option could include a requirement that energy be recovered from LFG as part of the control strategy. LFG has a significant heating value, about half that of natural gas, which makes it an energy source for the creation of electricity, heat, or alternate fuels such as pipeline quality gas or vehicle fuel. EPA, however, does recognize that there are challenges to this approach such as energy pricing, viability of potential end users or ability to connect to utility infrastructure.

For example, according to data submitted to EPA's Landfill Methane Outreach Program, Magnolia Landfill in Summerdale, AL is currently required to collect and combust landfill gas under the Landfill NSPS/emission guidelines. Collection and control of the landfill gas would provide an estimated extraction rate of 292 scfm in 2009. Utilizing the gas to generate electricity would result in the avoidance of 4,900 metric tons of CO₂e emissions due to displaced electricity generation from conventional fossil fuel sources.

Additionally, New Hanover County Landfill in Wilmington, NC reports that it is not currently required to collect and combust landfill gas under the Landfill NSPS/emission guidelines. Collection of the landfill gas at its estimated extraction rate of 898 scfm in 2009 would result in direct emissions reductions of 88,000 metric tons CO₂e

and utilizing the gas to generate electricity would result in the avoidance of 15,200 metric tons of CO₂e emissions due to displaced electricity generation from conventional fossil fuel sources.

A final option could include a requirement for the use of alternate cover designs to reduce methane emissions. According to AP-42, approximately 25 percent of LFG can be lost through the landfill cover. Emerging research on the dynamics associated with certain cover materials, depth, and temporal changes indicates that using alternate cover designs (e.g. use of compost to replace standard soil) can achieve additional emission reductions. This option could apply to landfills with and without control systems. However, additional studies would be needed to better define methane oxidation rates under different conditions, as well as to examine the availability and cost of suitable cover systems various geographic areas. While the use of various covers may provide additional emissions reductions, it is important to note that permeable covers may also augment uncontrolled emissions.¹⁷ To better assess fugitive losses from cracks and fissures in the landfill cover, leaks in wellheads and piping, and system malfunctions, emerging techniques such as radial plume mapping may also be used.

h. Agriculture

i. GHG emissions from the Agriculture and Forestry Sectors

The agricultural sector is a source of greenhouse gas emissions, but is not currently listed under section 111(a). In the Agency's draft document entitled "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006" this sector is estimated to have emitted 533.6 MMTCO₂e, or 8 percent of total U.S. greenhouse gas emissions in 2006. These emissions are from a variety of agricultural processes, and exclude on-farm energy use. This section provides an assessment of non-carbon-dioxide emissions from the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. Carbon dioxide emissions from on-farm energy use are not accounted for in this section.

The Agency's estimate of agriculture's greenhouse gas emissions is based on methodologies consistent with the "Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories" (IPCC/UNEP/OECD/IEA 1997), the "IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories" (IPCC 2000), the "IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry" (IPCC 2003), and the 2006 "IPCC Guidelines for National Greenhouse Gas Inventories" (IPCC 2006).

¹⁷ Thorneloe, S. A. U.S. EPA's Research to Update Guidance for Quantifying Landfill Gas Emissions Data. In Proceedings, Proceedings of the Eleventh International Waste Management and Landfill Symposium, Cagliari, Sardinia, Italy, Oct 1-5, 2007.

Although these methodologies enable the Agency to compute a national estimate of greenhouse gas emissions, these procedures have not been applied to determine whether source categories would be subject to specific regulatory requirements. Using these methodologies, the Agency has determined that CH₄ emissions from enteric fermentation and manure management represent about 24 percent and 10 percent of total CH₄ emissions from anthropogenic activities, respectively. Of all domestic animal types, beef and dairy cattle were by far the largest emitters of CH₄. Rice cultivation and field burning of agricultural residues were minor sources of CH₄. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N₂O emissions, accounting for 72 percent. Manure management and field burning of agricultural residues were also small sources of N₂O emissions.

Enteric Fermentation— During digestion, microbes resident in an animal's digestive system ferment food consumed by the animal. This microbial fermentation process, referred to as enteric fermentation, produces CH₄ as a by-product, which can be exhaled or eructated by the animal. The amount of CH₄ produced and emitted by an individual animal depends primarily upon the animal's digestive system, and the amount and type of feed it consumes. Total livestock CH₄ emissions from enteric fermentation in 2006 were 126.2 MMTCO₂e. Beef cattle remain the largest contributor of CH₄ emissions from enteric fermentation, accounting for 71 percent in 2006. Emissions from dairy cattle in 2006 accounted for 25 percent, and the remaining emissions were from horses, sheep, swine, and goats.

Livestock Manure Management - The management of livestock manure can produce anthropogenic CH₄ and N₂O emissions. Methane is produced by the anaerobic decomposition of manure. Direct N₂O emissions are produced as part of the nitrogen cycle through the nitrification and denitrification of the organic nitrogen in livestock manure and urine. Indirect N₂O emissions are produced as result of the volatilization of nitrogen as ammonia (NH₃) and nitrogen oxides (NO_x) and runoff and leaching of nitrogen during treatment, storage, and transportation.

Estimates of CH₄ emissions from manure management in 2006 were 41.4 MMTCO₂e, 34 percent higher than in 1990. Emissions increased on average by 0.6 MMTCO₂e, or (2.0 percent) annually over this period. The majority of this increase was from swine and dairy cow manure, where emissions increased 34 and 49 percent, respectively. Although the majority of manure in the United States is handled as a solid, producing little CH₄, the general trend in manure management, particularly for dairy and swine (which are both shifting towards larger facilities), is one of increasing use of liquid systems.

In 2006, total N₂O emissions from manure management were estimated to be 14.3 MMTCO₂e; in 1990, emissions were 12.1 MMTCO₂e. These values include both direct and indirect N₂O emissions from manure management. Nitrous oxide emissions have remained fairly steady since 1990.

Rice Cultivation - Most of the world's rice, and all rice in the United States, is grown on flooded fields. When fields are flooded, aerobic decomposition of organic material gradually depletes most of the oxygen present in the soil, causing anaerobic soil conditions. Once the environment becomes anaerobic, CH₄ is produced through anaerobic decomposition of soil organic matter by methanogenic bacteria. The CH₄ is transported from the submerged soil to the atmosphere primarily by diffusive transport through the rice plants. Minor amounts of CH₄ also escape from the soil via diffusion and bubbling through floodwaters.

In 2006, CH₄ emissions from rice cultivation were 5.9 MMTCO₂e. Although annual emissions fluctuated unevenly between the years 1990 and 2006, ranging from an annual decrease of 14 percent to an annual increase of 17 percent, there was an overall decrease of 17 percent over the sixteen-year period, due to an overall decrease in primary crop area. The factors that affect the rice acreage in any year vary from state to state, although the price of rice relative to competing crops is the primary controlling variable in most states.

Agricultural Soil Management - Nitrous oxide is produced naturally in soils through the microbial processes of nitrification and denitrification. A number of agricultural activities increase mineral nitrogen (N) availability in soils, thereby increasing the amount available for nitrification and denitrification, and ultimately the amount of N₂O emitted. These activities increase soil mineral N either directly or indirectly. Direct increases occur through a variety of management practices that add or lead to greater release of mineral N to the soil, including: fertilization; application of managed livestock manure and other organic materials such as sewage sludge; deposition of manure on soils by domesticated animals in pastures, rangelands, and paddocks (PRP) (i.e., by grazing animals and other animals whose manure is not managed); production of N-fixing crops and forages; retention of crop residues; and drainage and cultivation of organic cropland soils (i.e., soils with a high organic matter content, otherwise known as histosols).

Agricultural soils produce the majority of N₂O emissions in the United States. Estimated emissions from this source in 2006 were 265.0 MMTCO₂e. Annual N₂O emissions from agricultural soils fluctuated between 1990 and 2006, although overall emissions were 0.2 percent lower in 2006 than in 1990. Year-to-year fluctuations are largely a reflection of annual variation in weather patterns, synthetic fertilizer use, and crop production. On average, cropland accounted for approximately 80 percent of total direct emissions, while grassland accounted for approximately 20 percent.

Field Burning of Agricultural Residue - Farming activities produce large quantities of agricultural crop residues, and farmers use or dispose of these residues in a variety of ways. For example, agricultural residues can be left on or plowed into the field; composted and then applied to soils; landfilled; or burned in the field.

Alternatively, they can be collected and used as fuel, animal bedding material, supplemental animal feed, or construction material. Field burning of crop residues is not considered a net source of CO₂, because the carbon released to the atmosphere as CO₂ during burning is assumed to be reabsorbed during the next growing season. Crop residue burning is, however, a net source of CH₄, N₂O, CO, and NO_x, which are released during combustion. Field burning is not a widespread method of agricultural residue disposal in the United States. The primary crop types whose residues are typically burned in the United States are wheat, rice, sugarcane, corn, barley, soybeans, and peanuts. Less than 5 percent of the residue for each of these crops is burned each year, except for rice.

Annual emissions from this source over the period 1990 to 2006 have remained relatively constant, averaging approximately 0.8 MMTCO₂e of CH₄ and 0.4 MMTCO₂e of N₂O.

Forestry, Land Use and Land-Use Change – Overall, forestry, land use and land-use change activities are considered “sinks”, absorbing carbon dioxide from the atmosphere through a process known as carbon sequestration. In 2006 these activities resulted in removing 883.7 MMTCO₂e (240.8 MMT Carbon) of carbon from the atmosphere. Although these activities sequester carbon, forestry and land management activities do produce greenhouse gases. For example, in 2006 forest fires resulted in CH₄ emissions of 24.6 MMTCO₂e and in N₂O emissions of 2.5 MMTCO₂e. As long as the incidence and severity of wildfires remains constant, removal of carbon from the atmosphere through regrowth of vegetation in burned areas equals the wildfire carbon products emitted.¹⁸

ii. GHG Control Measures

The Agency has been actively involved in identifying control options to reduce air pollution emissions from livestock manure management and prescribed fires used for both silviculture and agriculture purposed (e.g., field burning of agricultural residue). However, the Agency has not addressed controlling air emissions from either rice cultivation or agricultural soil management due to the lack of applicable control techniques or technology. For livestock manure management, the Agency has focused on reducing CH₄ emissions through voluntary programs. With regard to controlling emissions from prescribed fires used for either silviculture or agriculture purposes, we have focused on reducing criteria pollutants emissions, primarily particulate matter, not greenhouse gases.

(1) Livestock Manure Management

Methane emissions occur whenever animal waste is managed in anaerobic conditions. Liquid manure management systems, such as ponds, anaerobic lagoons, and

¹⁸ [9-24-2007 USFS Congressional Testimony].

holding tanks create oxygen free environments that promote methane production. Manure deposited on fields and pastures, or otherwise handled in a dry form, produces insignificant amounts of methane.

The Agency working jointly with the U.S. Department of Agriculture sponsors the AgSTAR Program. AgSTAR is an outreach program that encourages the use of methane recovery (biogas) technologies at confined animal feeding operations that manage manure as liquids or slurries. These technologies reduce methane emissions while achieving other environmental benefits.

Three different types of biogas recovery systems have been commercialized for managing manures and are consistent with USDA-NRCS Anaerobic Digester Practice Standards. The most suitable type of system depends on climate, how manure is collected and on the total solids content of the collected manure.

(2) Field Burning of Agricultural Residue

Alternatives to replace agricultural burning include alternative crops, mechanical residue removal, and residue incorporation. The viability of these alternatives depends on several factors. First, the viability of any single alternative depends, in part, on its ability to meet the same resource objectives being accomplished by the agriculture burning. If the alternative cannot by itself meet the same resource objectives, then its viability depends on the development of other alternatives such that a combination of methods can provide the same resource objectives being accomplished by the agricultural burning. Second, free adoption of alternative methods by farmers depends on economic competitiveness. For example, open field burning in almost all cases has shown to be the most cost-effective practice. Third, the alternative must also be agronomically feasible. Any alternative that significantly reduces crop yields is not likely to be accepted by farmers or growers.

Also, the economic feasibility of mechanical residue removal depends on finding a market for the residue. In general, residue use in most markets faces a large economic handicap: most residues are dispersed over large areas, requiring costly collection; or far from markets, requiring costly transportation; limited in quantity, quality, or dependability, resulting in lower value to the buyer. The viability of alternative uses varies substantially among types of crop residues. For example, there are more potential uses for the residues from field crops such as wheat, barley, and corn than from rice.

(3) Forest Land

Changes in climate and fire management practices over the last several years have resulted in conditions that have contributed to an increase in forest fire frequency, intensity and duration. There are three general means by which agricultural and forestry practices can reduce greenhouse gases: avoid emissions by maintaining existing carbon

storage in trees and soils through fire and fuels management; increase carbon storage through sustainable forest management and reforestation; substitute bio-based fuels and products for fossil fuels, such as coal and oil, and energy-intensive products that generate greater quantities of CO₂ when used.

iii. Interaction with Other Rules

None of the agriculture activities addressed in this section are currently regulated under the Clean Air Act's New Source Performance Standard (NSPS), and a significant question remains whether these activities are among those for which Congress intended EPA to develop such standards. However, some States and Tribes have regulated prescribed fires, used for either silviculture or agricultural practices, in order to meet either national ambient air quality standards or regional haze requirements. Although these regulations have focused on reducing criteria pollutant emissions (primarily particulate matter), the Agency believes that these regulations also provide co-benefits by reducing greenhouse gases.

Regarding livestock and associated manure management, the Agency is engaged in an extensive multi-year study to quantify various air pollutants (among them, methane) from certain types of confined animal feeding operations. Data gathered as a part of this study will guide and influence the Agency's decision regarding the appropriate policy for this sector.

VII.: Stationary Source Authorities and Potential Options for Regulating Greenhouse Gases under the Clean Air Act

C. Section 112 – National Emission Standards for Hazardous Air Pollutants

No additional technical information.

VII.: Stationary Source Authorities and Potential Options for Regulating Greenhouse Gases under the Clean Air Act

D. Preconstruction permits under the Prevention of Significant Deterioration Program

See the above section on National Ambient Air Quality Standards. Provisions for PSD and NSR are tied directly to the setting and implementation of a National Ambient Air Quality Standard (NAAQS).

VII.: Stationary Source Authorities and Potential Options for Regulating Greenhouse Gases under the Clean Air Act

E. Title V Operating Permits Program

INTERNAL USE ONLY

42

DO NOT DISTRIBUTE

June 5, 2008

Final Draft

List of Documents for GHG ANPR Docket, adjacent to this TSD

Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005, EPA, 2007

Energy Trends in Selected Manufacturing Sectors, EPA, 2007

Annual Energy Outlook with Projections to 2030, EIA, 2007

IPCC Fourth Assessment Report, Working Group III, Final Draft, Chapter 7

Characterization of the U.S. Industrial Commercial Boiler Population, Oak Ridge National Laboratory, May 2005

Efficiency and Innovation in U.S. Manufacturing Energy Use, National Association of Manufacturers, 2005

Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries, LBNL, 2005

U.S. Pulp and Paper Mills Online Database, June 2005

Opportunities to Improve Energy Efficiency and Reduce Greenhouse Gas Emissions in the U.S. Pulp and Paper Industry, LBNL, 2000

Cost and Performance Baseline for Fossil Energy Plants, DOE/NETL-2007/1281

Biomass Co-firing Update 2002, EPRI 1004319, Final Report, July 2003

Energy Efficiency and Carbon Dioxide Emissions Reduction Opportunities in the U.S. Cement Industry, LBNL, 1999

Energy and Emission Reduction Opportunities for the Cement Industry, DOE, December 2003

Energy Efficiency and CO₂ Emissions Reduction Opportunities in the U.S. Iron and Steel Sector, LBNL, 2001

EIA Manufacturing Energy Consumption Survey

Inventory of Large Non-Utility Boilers (Draft), U.S. EPA/OAP, October 2006

INTERNAL USE ONLY

44

DO NOT DISTRIBUTE

June 5, 2008

Final Draft

Memorandum Regarding Estimates of Number of Major Sources (w/ Supporting Report & Spreadsheets)

Summary for Selected Stationary Sources (slide presentation).

Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final)