TECHNICAL SUPPORT DOCUMENT FOR REVISION OF CERTAIN PROVISIONS: PROPOSED RULE FOR MANDATORY REPORTING OF GREENHOUSE GASES

Office of Air and Radiation
U.S. Environmental Protection Agency
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Subpart A

Background on Accuracy and Calibration Requirements[1]

Background: The current rule provides, with limited exceptions, that "flow meters and other devices (e.g., belt scales) that measure data used to calculate GHG emissions shall be calibrated prior to April 1, 2010 using the procedures specified in this paragraph and each relevant subpart of this part. All measurement devices must be calibrated according to the manufacturer's recommended procedures, an appropriate industry consensus standard, or a method specified in a relevant subpart of this part. All measurement devices shall be calibrated to an accuracy of 5 percent." Measurement devices that may be used to comply with the rule include:

- Fuel Mass Flow Meters;
- Fuel Volumetric Flow Meters;
- Weighing Systems;
- Tank Level Sensor;
- Acid Concentration Monitor; and
- Methane Analyzer.

EPA has received a number of comments on what the 5% accuracy requirement really means, which measurement devices it should be applied to, and whether 5% is an appropriate value. Based on these questions, we are reviewing the calibration and accuracy requirements in the rule. This document provides some background materials gathered and evaluated in developing the proposal.

Accuracy Requirements in Other Reporting Programs

1. **Acid Rain Program and NO_X Budget Program**

    - Requirements for Continuous Emissions Monitoring are described in 40 CFR Part 75. The performance specifications for fuel flow meters under Part 75, Appendix D state:
        - Conduct a flow meter accuracy test using American Society of Mechanical Engineers (ASME) methods or using comparison to a reference flow meter designed to American Gas Association (AGA) standards.
        - Error must be no more than 2.0 percent of full scale (initial calibration and periodic QA).
        - QA test required annually.

    - Information from the Acid Rain Program accuracy tests between 2005 and 2009 show:
        - Fuel flow meter accuracy ranged between 0.10 and 0.40 percent; and
        - Transmitter transducer accuracy ranged between 0.20 and 0.50 percent.

[1] Developed with support from Eastern Research Group.

Tables A-1 and A-2 in Appendix A summarize the Acid Rain Program accuracy test results.

2. California Mandatory GHG Reporting Program

- Section 95103(a)(9) of Subarticle 1 General Requirements for the Mandatory Reporting of Greenhouse Gas Emissions of the California GHG Reporting Rule has an accuracy requirement for fuel use measurements that states:

  "Fuel Use Measurement Accuracy. The operator shall employ procedures for fuel use data measurements (mass or volume flow) used to calculate GHG emissions that quantify fuel use with an accuracy within ±5 percent. All fuel use measurement devices shall be maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. The operator shall make available to the verification team documentation to support this level of accuracy. The operator who measures solid fuels shall validate fuel consumption estimates with belt or conveyor scale calibrations conducted at least quarterly, and retain record of such calibrations." (http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm)

- California originally proposed an accuracy requirement of ±2.5 percent. The Final Statement of Reasons for Rulemaking responded to public comments regarding the accuracy requirement. Commenters stated that the ±2.5 percent uncertainty requirement is too stringent and is not achievable with most of the existing flow measurement devices used in the petroleum industry.

- California also recognized there could be measurement difficulties for some facilities and fuel types, including solid fuels. The response to comments document concluded that, "Because it is impractical to write into the regulation detailed specifications for evaluating the absolute accuracy of measurements for each solid fuel, we chose to require in section 95103(a)(9) that facility operators employ procedures to ensure a fuel activity accuracy of ±5 percent. Operators must maintain and calibrate equipment to meet this level of accuracy, and maintain appropriate records.

- California modified the original accuracy requirement of ±2.5 to ±5.0 percent for the final rule.

- The California regulation and Final Statement of Reasons for Rulemaking did not contain additional detail on the rational for the 5 percent accuracy requirement or the change from the original 2.5 percent requirement.

What is the typical range of accuracy achievable for other measurement devices used in Part 98 (e.g., belt scales, weigh hoppers, truck weigh scales)?

- Based on information from internet product searches and vendor information, measurement devices typically have accuracy ranges less than ± 5 percent.

- The Instrument Engineers Handbook lists load cell performance specifications for individual load cells which have accuracy ranges between 0.03 and 1 percent. Table A-3 in Appendix A lists typically accuracies for various types of load cells.

- Vendor information found through internet searches also showed accuracy ranges of less than 5 percent. The accuracy ranges obtained from the vendor information for devices that may be used in GHG reporting are listed below. Table A-4 in Appendix A contains the detailed information by vendor.
  - Mass flow meter – 0.2 percent to 1 percent;
  - Volumetric flow meter – 0.125 to 1 percent;
  - Load cell accuracy – 0.02 to 5 percent;
  - Liquid level sensors – 0.075 to 2 percent;
  - Concentration monitors – 0.1 to 2 percent; and
  - Landfill gas monitors – 0.1 to 3 percent.

Uniform Accuracy Requirements Across Part 98 Versus Subpart-specific?

- The range of accuracy of new measurement technologies on the market today does not suggest that different accuracy requirements are needed by type of technology, if the required standard is near 5%. If differentiation is needed, it may be driven by the cost of maintenance and replacement of older equipment that cannot meet the 5% requirement. Therefore, if differentiation is necessary, it may be needed by industry rather than technology, as explained below.

- The standards for accurately weighing raw materials and products are likely to vary between industries, and between facilities within an industry, and even among separate processes within a single facility.

- Different processes are likely to be more or less tolerant of different accuracies, so a single standard for accuracy is probably not in practice among all industries.

- Different standards for accuracy also apply depending on whether the material is being weighed and used within a plant for process control, or weighed as part of a sale or purchase in commerce. Process control may not require the same level of accuracy as in commerce.

- Additional information from specific industries could be needed to identify the customary level of accuracy associated with those industries and variables that are of most critical interest in the GHG emission calculations.

- In commerce, weighing devices are likely to conform to NIST Handbook 44, if a device is used. Pennsylvania, for example, specifies that weighing devices used in commerce must comply with NIST Handbook 44 (see, for example, Pa. Code Title 70, Weights, Measures And Standards; Chapter 10. Device Type Approval; http://www.pacode.com/secure/data/070/chapter10/chap10toc.html). Enforcement, inspection, and certification ("sealing") is done at the county level.

Appendix A – Supporting Tables

TABLE A-1. SUMMARY OF FUEL FLOWMETER ACCURACY TEST BETWEEN 2005 & 2009					
ACCURACY TEST METHOD CODE DESCRIPTION	**TEST METHOD CODE**	**TOTAL TEST**	**AVG LOW LEVEL ACCURACY (PERCENT)**	**AVG MID LEVEL ACCURACY (PERCENT)**	**AVG HIGH LEVEL ACCURACY (PERCENT)**
AGA Report No. 7, Measurement of Natural Gas by Turbine Meter	AGA7	19	0.10	0.10	0.10
American Petroleum Institute Method in Appendix D	API	32	0.20	0.20	0.20
ASME Method in Appendix D	ASME	40	0.40	0.20	0.30
In-Line Comparison against Master Meter at Facility	ILMMF	251	0.10	0.20	0.30
International Organization for Standardization Method in Appendix D	ISO	33	0.30	0.30	0.40
Laboratory Comparison against Reference Meter	LCRM	530	0.20	0.20	0.20
NIST-Traceable Method Approved by Petition	NIST	84	0.20	0.20	0.20

TABLE A-2. SUMMARY OF TRANSMITTER TRANSDUCER TEST BETWEEN 2005 & 2009							
TEST TYPE		**LOW LEVEL ACCURACY**		**MID LEVEL ACCURACY**		**HIGH LEVEL ACCURACY**	
ACCURACY SPEC CODE DESCRIPTION	**ACCURACY SPEC CODE**	**TOTAL TEST**	**AVG (PERCENT)**	**TOTAL TEST**	**AVG (PERCENT)**	**TOTAL TEST**	**AVG (PERCENT)**
Actual Accuracy of Each Component	ACT	1,221	0.20	1,198	0.20	1,198	0.20
Sum of Accuracies of All Components	SUM	678	0.30	703	0.50	702	0.50

Table A-3. Load Cell Performance Comparison					
Type	**Weight Range**	**Accuracy (Full Scale)**	**Applications**	**Strengths**	**Weaknesses**
Mechanical Load Cells					
Hydraulic Load Cells	Up to 10,000,000 lb	0.25%	Tanks, bins and hoppers. Hazardous areas.	Takes high impacts, insensitive to temperature.	Expensive, complex.
Pneumatic Load Cells	Wide	High	Food industry, hazardous areas	Intrinsically safe. Contains no fluids.	Slow response. Requires clean, dry air
Strain Gage Load Cells					
Bending Beam Load Cells	10-5,000 lbs.	0.03%	Tanks, platform scales,	Low cost, simple construction	Strain gages are exposed, require protection
Shear Beam Load Cells	10-5,000 lbs.	0.03%	Tanks, platform scales, off-center loads	High side load rejection, better sealing and protection	
Canister Load Cells	to 500,000 lbs.	0.05%	Truck, tank, track, and hopper scales	Handles load movements	No horizontal load protection
Ring and Pancake Load Cells	5- 500,000 lbs.		Tanks, bins, scales	All stainless steel	No load movement allowed
Button and washer Load Cells	0-50,000 lbs 0-200 lbs. typ.	1%	Small scales	Small, inexpensive	Loads must be centered, no load movement permitted
Other Load Cells					
Helical	0-40,000 lbs.	0.20%	Platform, forklift, wheel load, automotive seat weight	Handles off-axis loads, overloads, shocks	
Fiber optic		0.10%	Electrical transmission cables, stud or bolt mounts	Immune to RFI/EMI and high temps, intrinsically safe	
Piezo-resistive		0.03%		Extremely sensitive, high signal output level	High cost, nonlinear output

Source: Instrument Engineers Handbook, Process Measurement and Analysis, Fourth Edition, 2003

<table>
<tr><th colspan="3">Table A-4. Example Vendors for Measurement Devices and Device Accuracy</th></tr>
<tr><th colspan="1">Vendor</th><th colspan="2">Accuracy</th></tr>
<tr><th colspan="3">Mass Flow Meters</th></tr>
<tr><td>Alicat Scientific</td><td colspan="2">0.8% of reading + 0.2% of full scale for most models</td></tr>
<tr><td>Sierra Instruments</td><td colspan="2">1% of full scale for most models</td></tr>
<tr><td>MKS Instruments</td><td colspan="2">1% of full scale for most models</td></tr>
<tr><td>TSI</td><td colspan="2">2% of reading a full scale for most models</td></tr>
<tr><td>Brooks Instrument</td><td colspan="2">0.2%, 0.5% or 1% depending on model</td></tr>
<tr><td>Bronk Horst High Tech</td><td colspan="2">0.2% of reading and 0.2% of full scale</td></tr>
<tr><td>Fluid Components International</td><td colspan="2">0.5% for gases</td></tr>
<tr><th colspan="3">Volumetric Flow Meters</th></tr>
<tr><td>Sure Flow Products</td><td colspan="2">0.5% - 1% of full scale</td></tr>
<tr><td>Instramart</td><td colspan="2">0.8% of reading + 0.2% of full scale for Flocat LA10-A Gas flow meter</td></tr>
<tr><td>Liquid Controls</td><td colspan="2">0.125 – 0.5% of reading – liquid volume meters</td></tr>
<tr><th colspan="3">Liquid Level Sensors</th></tr>
<tr><td>SensorOne</td><td colspan="2">0.25% of full scale for most products</td></tr>
<tr><td>SSI Technologies Inc</td><td colspan="2">2% of full scale</td></tr>
<tr><td>Endress+Hauser</td><td colspan="2">0.075% to 0.2%</td></tr>
<tr><th colspan="3">Concentration Monitors (for liquid acids and bases)</th></tr>
<tr><td>Horiba</td><td colspan="2">1% for most products</td></tr>
<tr><td>Jetalon Solutions, Inc</td><td colspan="2">0.1% for the CR-288</td></tr>
<tr><td>Analytical Technology, Inc</td><td colspan="2">2% of full scale for Q45/85 Peracetic acid monitor</td></tr>
<tr><th colspan="3">Landfill Gas Monitors</th></tr>
<tr><td>Geotech GA2000 Portable Gas Analyzer</td><td colspan="2">Gas Accuracy depends on concentration level:
CH_4: ±0.5 – 3.0
CO_2: ±0.5 – 3.0
O_2: ±1.0</td></tr>
<tr><td>Enviro-Equipment, Inc. CES-LANDTEC GEM-2000</td><td colspan="2">CH_4: Range 0-100% Resolution 0.1%
CO_2: Range 0-60% Resolution 0.1%
O_2: Range 0-25% Resolution 0.1%
Flow Accuracy ±3% 50-150 SCFM</td></tr>
<tr><th colspan="3">Load Cells</th></tr>
<tr><th>Vendor</th><th>Equipment Type</th><th>Accuracy (full scale)</th></tr>
<tr><td rowspan="4">Honeywell</td><td>Compression Canister Load Cells</td><td>1%</td></tr>
<tr><td>S-Beam Load Cells</td><td>0.02%</td></tr>
<tr><td>Pancake Type Load Cells</td><td>0.1%</td></tr>
<tr><td>Ring Type Load Cells</td><td>1%</td></tr>
<tr><td rowspan="4">ADI Artech</td><td>S-Beam Load Cells</td><td>1%</td></tr>
<tr><td>Shear Beam Load Cells</td><td>1%</td></tr>
<tr><td>Bending Beam Load Cells</td><td>1%</td></tr>
<tr><td>Compression Canister Load Cells</td><td>1%</td></tr>
<tr><td>Eilerson Insdustrial Sensors</td><td>Various Load Cell Types</td><td>0.25%</td></tr>
<tr><td>Control Systems</td><td>Weigh Hoppers</td><td>0.5%</td></tr>
</table>

Table A-4. Example Vendors for Measurement Devices and Device Accuracy		
Technology	Belt Feeder	0.1-5%
Siemens Industry USA	Weigh Hoppers	0.25-0.5%
	Belt Weighers	0.5-2%
Avery Weigh Tronics	Truck and Railroad Scales	0.25-0.4% (static) 0.5% or +/- 400 lbs; whichever is higher (in motion)
	Floor Scales	0.05%
	Compression Load Cells	0.05%
Kistler-Morse	Compression Load Cells	0.08%
Rice Lake Weighing Systems	Belt Scales	0.25%

Calibration- Temperature and Pressure Transmitters for Orifice, Nozzle, and Venturi Meters

Based on conversations with industry since release of the 2009 Final Rule, EPA learned of a concern regarding temperature and pressure transmitters for orifice, nozzle and venturi meters. Specifically, the petroleum refining and petrochemical industry informed us that some existing meters in refinery fuel gas systems do not have temperature and total pressure sensors and transmitters installed immediately adjacent to the meter. However, some of these installations have one pressure and temperature measurement point that can provide compensation information for the particular fuel line or system and meters installed on the line or system. The industry expressed concern that new pressure and temperature monitors cannot be safely added without a facility or unit shut-down unless the system can be securely isolated and bypassed to enable continued unit operation. Moreover, they noted that even if a system can be isolated, the work involved to plan, engineer, and execute the installation and tie in of these devices to the process data systems will take considerable time and may not be feasible before the end of 2010.

The industry representatives suggested that conditions at a flow meter can be reliably and accurately represented by temperature and pressure indications remote from the flow meter, and therefore that the use of remote temperature and pressure indication should be allowed if a reporter can demonstrate that these can be used to provide representative compensation for the remotely located fuel meter. The industry representatives provided the approaches described in the following paragraphs as examples of potential methods to demonstrate that a remote measurement provides a representative indication:

A. Representative Conditions

In order to determine if the remote temperature and pressure values are representative of conditions at the flow meter, temperature and pressure surveys could be conducted to determine the difference between the readings at the transmitters not proximal to the meter and the actual conditions at the meter. A typical temperature survey involves the use of an infrared gun, reading local gauges, or an equivalent method and recording the temperature for each flow meter, near each flow meter. If a temperature transmitter is not proximal to the meter, the difference between the recorded value and the monitored temperature is recorded to give a temperature loss for the line. This temperature loss, if significant, is then used to correct the monitored temperatures for the particular flow meter. Pressure throughout a system is not expected to vary as widely and could be determined through a pressure survey or calculated using standard fluid dynamics equations, with the resulting calculated result used to compensate the measured flow at the fuel metering device. A pressure survey generally involves using a calibrated pressure gauge to measure the pressure in the pipe at, or as close as possible to, the meter. The measured pressure would then be compared to the pressure monitoring from an existing transmitter on the line/system and an appropriate “correction factor” calculated to correct the live pressure transmitter readings to the corrected pressure at the meter.

B. Corrections

In the event a correction is needed to account for temperature and pressure changes, such corrections could be done by applying a “correction factor” to the measured values based on comparisons in the data handling/calculation systems, such as through the temperature and pressure surveys described above.

C. Active Compensation

Active compensation, in the context discussed, is the automated feed of the measured total pressure and temperature information into the metering calculation system algorithms periodically (e.g., every minute or every 10 minutes). In many current configurations, the total pressure and temperature data used in these algorithms are constants set to provide a reasonable match with the system in question. The sensors and transmitters furnishing the automated pressure and temperature data may be located adjacent to the meter or on the same line/system remote from the meter.

Background Information on BAMM

Based on conversations with the petrochemical and petroleum refining industry since release of the 2009 Final Rule, EPA learned of a concern regarding the ability to install measurement devices in 2010 if installation would require a unit (or process line or facility) shutdown or a hot tap. In the context of these discussions, industry representatives provided additional information regarding (i) the circumstances that would justify use of Best Available Monitoring Methods (BAMM) beyond 2010, and (ii) the proposed process for implementing BAMM beyond 2010.

The industry representatives surveyed members of their trade associations to obtain information related to this issue. According to the industry representatives, twenty-three companies responded from a broad cross-section of the industry ranging from companies that have a single refinery to the large household names that have several refineries in the United States. These respondents operate facilities ranging from refineries that make a single product with a limited range of process units to plants which produce a much larger number of products and have a substantial number of process units at the facility. According to the representatives, it is common knowledge that refineries vary substantially in their capacity and production, thus there is no such thing as the typical refinery.

According to the information provided by the industry representatives, the appropriate time to install new monitoring equipment is during normally scheduled shutdowns or turnarounds because:

- It avoids the inherent safety risks of hot tapping;
- It minimizes the costs to install monitoring equipment; and
- In the interim, prior to equipment installation, there are suitable methods to determine the greenhouse gas emissions which are adequate for reporting purposes.

Industry noted that while there are some rare situations in which the bypass or isolation of the equipment could enable a monitoring device to be installed while the process continues to operate, it would be impossible to estimate for purposes of these revisions the number of such specific situations at the present time because it would require an engineering review of pipe configuration and other engineering considerations at each monitor site and would inevitably require months to complete. Rather, it is an issue that is better suited to be addressed in the context of an individual application to continue a limited use BAMM after 2010.

According to the industry representatives none of the companies reported that their turnaround cycles for Crude Distillation Units, Vacuum Distillation Units, FCCUs, Distillate Hydrotreating Units, Cat Feed Hydrotreaters, Hydrocrackers, Hydrogen Plants, Catalytic Reformers, Coking Units, Sulfur Recovery Units, Boilers or Steam Generation Units, or Cogeneration Units were one year or less. Seven companies did report that their turnarounds varied for Boilers or Steam Generation Units, with at least some on a one year cycle; six companies noted similar turnarounds for Catalytic Reformers.

When asked how long BAMM would be needed for each type of unit, industry provided the typical range of turnaround cycles provided by the companies with regards to the units listed above. They also noted that there is no generally applicable cycle for the entire industry for any of these units; in addition, the companies typically vary the cycle between refineries to avoid having all of the manufacturing capacity shut down at the same time. Industry also emphasized that there are exceptions to the ranges provided below both on the high side and on the low side and thus the ranges provided are not all inclusive but a range that covers the larger part of the industry. All the ranges are in years.

Crude Distillation Units: 4 – 7
Vacuum Distillation Units: 4 – 6
FCCU: 4 – 5
Distillate Hydrotreating Units: 3 – 5
Cat Feed Hydrotreaters: 3 – 5
Hydrocrackers: 3 – 5
Hydrogen Plants: 2 – 5
Coking Units: 3 – 5
Sulfur Recovery Units: 3 – 5
Cogeneration Units: 3 – 5

The industry representatives also provided information regarding what types of monitoring devices are most at issue regarding installation in 2010, noting that their survey showed that fuel gas meters and/or their associated sensors, transmitters, and piping are the most problematic devices for the refining sector in this time frame. They stated that if all monitoring devices had to be installed in 2010, facilities would likely be required to engage in a number of "hot taps" (and assume their inherent risks and hazards to worker safety and facility operations) to install specific instruments. The industry representatives considered "hot-tapping" to be the installation of devices which penetrate the pipe or vessel wall while in service, which involves welding a special fitting on the pipe or vessel exterior, installing a full-bore opening valve on this fitting, using specialty tools to drill a hole through the wall, and then installing the device through the penetration created. According to industry, the risks with hot-tapping are:

- Uncontrolled release of flammable and/or explosive gases and the risk of ignition and fire or flash fire; and
- Burn-through and ignition while welding the fitting on the pipe/vessel.

The industry representative also noted that hot-tapping is regulated under OSHA regulations at 29 C.F.R. 1910.147(a)(2)(iii)(B), and that OSHA-mandated criteria regulating this activity discourage hot tapping in order to limit the risk of employee injury.

Regarding the frequency by which processes or units are shut down, industry representatives indicated that, ideally, process unit shutdowns and turnarounds are the same, and if unscheduled shut downs do occur, they tend to be short and the units are restarted as quickly as safe operations allow. According to industry representatives, it is generally not feasible to install new equipment during unscheduled unit outages.

Subpart C

Heterogeneity and Variability of Municipal Solid Waste in Relation to Municipal Waste Combustor Emissions[2]

Background and Summary

MSW is a fuel for MWCs, which are a category of stationary combustion sources covered under Subpart C of EPA's Mandatory Greenhouse Gas Reporting rule (2009). Subpart C requires stationary combustion sources to report their carbon dioxide emissions and establishes four tiers of methods for stationary combustion sources to calculate or physically measure their carbon dioxide emissions. These include:

- Tier 2: Mass Balance Calculations. This method estimates the annual mass of CO_2 emissions for MWCs by multiplying the mass of steam generated by MSW combustion, by the efficiency of steam generation and by a default CO_2 emission factor for MSW.

- Tier 4: Continuous Emissions Monitoring. This method requires hourly measurements of CO_2 concentration and stack gas volumetric flow rate to calculate the mass of CO_2 emissions.

Carbon dioxide (CO_2) emissions from MWCs are a function of the composition of MSW that they burn for fuel. As a result, the choice of monitoring techniques will depend upon the extent to which the composition of MSW used as a fuel for combustion in MWCs varies.

Under Subpart C, MWCs with a maximum rated heat capacity greater than 250 tons per day are required to apply the Tier 4 method and use continuous emissions monitoring systems to directly measure their carbon dioxide emissions on a continuous basis if the unit meets the six requirements in 98.33(b)(4)(ii). Units equal to or less than 250 tons per day are required to use Tier 4 if they meet the three conditions outlined in 98.33 (b)(4)(iii). Stakeholders have expressed concern, contesting the requirement for the Tier 4 monitoring method. The stakeholder advocates the use of the Tier 2 mass balance estimate method instead, asserting that application of the Tier 4 method is 'costly' and that there is 'no logical basis' for this requirement in the stated purpose of the Mandatory Greenhouse Gas Reporting Rule.

The purpose of this document is to provide background on the factors influencing MSW composition variability, how these factors contribute to variability in CO_2 emissions through the carbon content and ratio of fossil carbon to biogenic carbon[3] in MSW, and the range of possible variation of composition.

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[2] Developed with support from Christopher Evans, Robert Lanza, Randy Freed, and Veronica Kennedy, ICF International

[3] Carbon-based components of MSW are distinguished into fossil and biogenic fractions because these fractions are accounted for differently under IPCC guidelines for developing national greenhouse gas inventories (IPCC 2006) and are required to be reported separately under Subpart C of the MRR. The biogenic fraction of MSW includes biomass-derived materials containing carbon that, under natural conditions, would cycle back to the atmosphere as

Both the overall carbon content and the ratio of fossil carbon to biogenic carbon of MSW varies according to the composition of biogenic and non-biogenic carbon-based materials in the MSW. The principal components and average national composition of MSW in 2008 are shown in Table 1, as estimated by EPA (2009) in *Municipal Solid Waste Generation, Recycling, and Disposal in the United States Detailed Tables and Figures for 2008*.

Table 1: Principal components of MSW and amount of each component generated in the United States in 2008 (EPA 2009)

Material	Generation short tons	Share of total
Paper	77,420	31%
Glass	12,150	5%
Metals	20,850	8%
Plastics	30,050	12%
Rubber and leather	7,410	3%
Textiles	12,370	5%
Wood	16,390	7%
Food scraps	31,790	13%
Yard trimmings	32,900	13%
Miscellaneous inorganic wastes	3,780	2%
Other	4,500	2%
Total	249,610	100%

Non-biogenic carbon-based materials primarily consist of plastics, synthetic textiles, and rubber; biogenic materials include paper, natural textiles (e.g., cotton, linen), wood, food waste, and yard trimmings (EIA 2007). Glass and metals are inorganic materials.

There are four types of compositional variability in the MSW stream: variability in the definition of MSW, geographic variability, seasonal variability, and long-term compositional trends. Each of these factors is discussed below. Each factor can result in considerable site-specific variation in the CO_2 emissions from MWCs and the ratio of fossil to biogenic CO_2 in MSW burned in MWCs. Consequently, CO_2 emissions from MWCs are much harder to characterize accurately using mass balance or other calculation methods than are CO_2 emissions from other stationary combustion sources covered under Subpart C of EPA's Mandatory Greenhouse Gas Reporting rule (2009). Other types of stationary combustion sources such as fossil fuel-fired combustors generally have a relatively homogeneous fuel source with relatively well-characterized fossil C content.

Description of four types of variability in the MSW stream

Variability in the definition of MSW

CO_2 due to degradation processes. As a result, CO_2 emissions from biogenic materials from sustainably-grown biomass are not included in inventories of human-caused greenhouse gas emissions. The fossil fraction of MSW includes materials that are derived from fossil fuels that have been sequestered under the earth. When fossil-based materials are extracted from the earth and converted into CO_2 or other greenhouse gases, they are considered anthropogenic emissions and are included in inventories. For more information, please refer to IPCC (2006) and EPA (2006, p. 13).

Municipal solid waste or MSW can be defined as solid phase household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil, wood pellets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), clean wood, industrial process or manufacturing wastes, medical waste, or motor vehicles (including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials, limited to vehicle batteries and tires, except where a single waste stream consisting of tires is combusted in a unit.

Biocycle magazine's *State of Garbage in America* series has reported frequently[4] on the challenges of characterizing the generation and composition of MSW. Inconsistencies in state-level data led Biocycle to revise its methodology for estimating the generation and composition of MSW (Biocycle 2004), but problems persist in compiling an accurate estimate of MSW generation and composition in the United States through a state-by-state bottom-up estimate (Biocycle 2006, p. 28):

- Wastes that are typically not considered part of the MSW stream, such as construction and demolition materials, automobile scrap, industrial wastes, biosolids, and agricultural wastes, may be classified as MSW in state estimates.

- Each state has its own method for collecting state-wide MSW management information; there is a high degree of certainty in the overall tonnages of MSW that are landfilled and that are combusted due to reporting requirements, but recycling and yard trimming composting facilities are often not required to report throughput; and

- Exported MSW is not tracked by all states, and some states are not able to distinguish non-MSW waste exports from MSW exports.

Challenges in accurately and consistently defining the wastes that constitute MSW can lead to mischaracterization of MSW as a fuel for combustion in MWCs. Non-MSW wastes may have substantially different carbon contents and fractions of fossil and biogenic components; for example, wood can form a large share of construction and demolition debris. Consequently, CO_2 emissions from wastes considered MSW that are combusted in MWCs, but which fall outside of EPA's definition of MSW, can lead to different CO_2 emissions than might be predicted using default emission factors.

[4] Usually Biocycle runs their "State of Garbage in America" article annually, but there have been occasional gaps.

Geographic variability

The composition of MSW varies geographically across the United States. Geographic variability is driven by factors such as the following (EPA 2008, p. 21):

- "Variance in the per capita generation of some products, such as newspapers and telephone directories, depending upon the average size of the publications. Typically, rural areas will generate less of these products on a per person basis than urban areas.

- "Level of commercial activity in a community. This will influence the generation rate of some products, such as office paper, corrugated boxes, wood pallets, and food scraps from restaurants.

- "Variations in economic activity, which affect waste generation in both the residential and the commercial sectors.

- "Local and state regulations and practices. Deposit laws, bans on landfilling of specific products, and variable rate pricing for waste collection are examples of practices that can influence a local waste stream."

MSW combustion occurs predominantly in the northeast and southern regions of United States, shown in Table 2. According to Figure 1, Connecticut combusts 65% of its MSW, and Florida, Hawaii, Maine, and Massachusetts manage over 20% of their MSW in waste-to-energy projects[5]. Twenty states do not have any MWCs within their borders.

Table 2: Municipal waste-to-energy projects by U.S. region (EPA 2008, p. 151)

Region	Number Operational	Design Capacity (tpd)
NORTHEAST	40	46,537
SOUTH	23	31,131
MIDWEST	16	10,912
WEST	8	6,141
*U.S. Total**	87	94,721

[5] MWCs account for roughly 90% of MSW processed in waste-to-energy projects (EPA 2008, p. 151). The remaining 10% is largely made up of tires, which are sent separately to cement kilns, utility boilers, pulp and paper mills, industrial boilers, and dedicated tire-derived fuel facilities for combustion. (EPA 2008, p. 151)

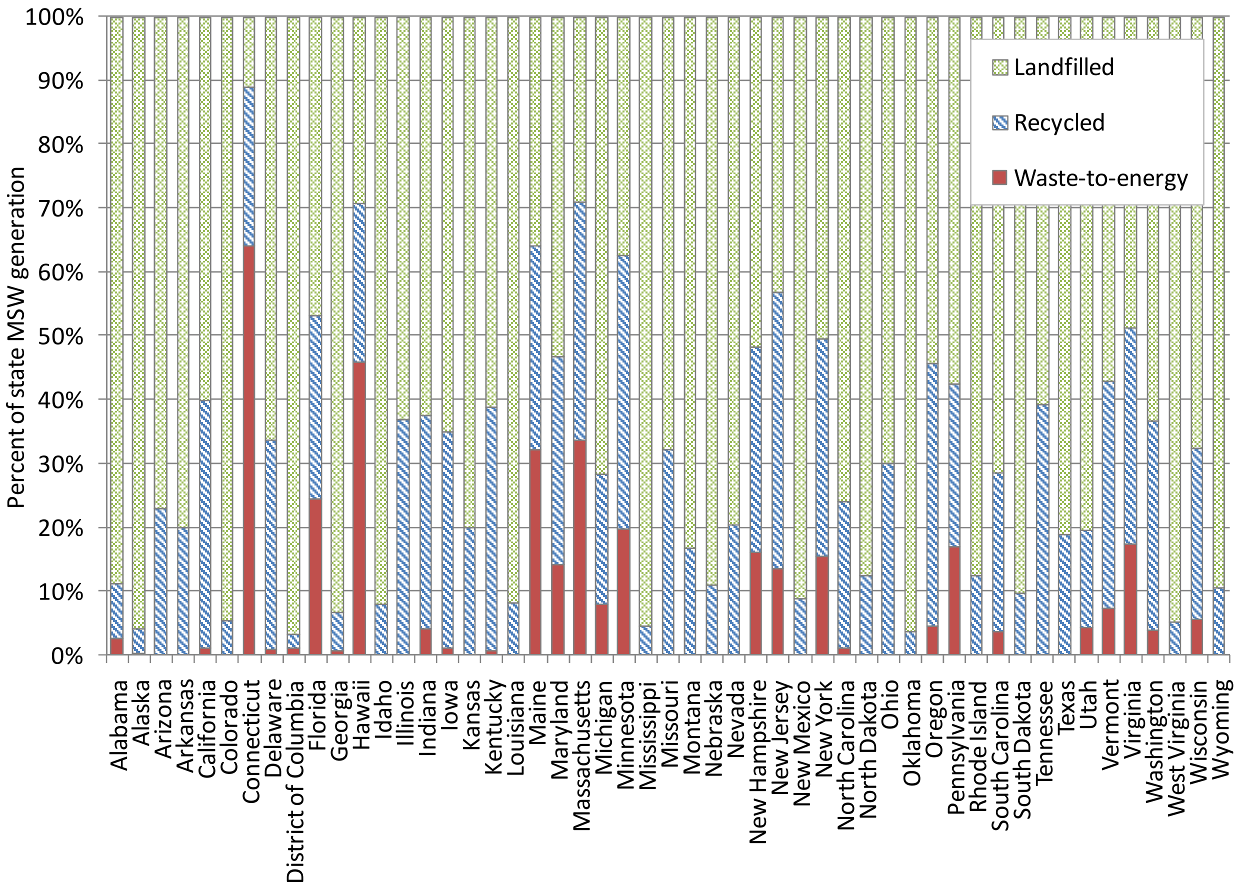


Figure 1: Share of waste management methods employed by U.S. states, as a percentage of total tonnage of MSW generation (Adapted from Arsova et al., 2008)

As shown in Figure 2, bans on scrap tires, used oil, and lead-acid batteries are common, but bans on other types of goods such as yard trimmings, white goods, and electronics are more variable. State-level regulations banning disposal of materials in MSW landfills can influence the composition of waste that is sent to MWCs. Often the regulations govern waste haulers. The boundaries of "wastesheds" can shift day by day as a function of relative tipping fees for landfilling versus combustion. Thus, as the haulers (and/or the municipalities they serve) try to divert materials from landfills, they also divert them from combustors.

State	Yard Trimmings	Whole Tires	Used Oil	Lead-Acid Batteries	White Goods	Electronics	Others
Alaska			x	x			
Arizona		x			x		
Arkansas	x	x		x		x[1]	
California		x	x		x	x	x[2]
Connecticut	x[3]			x			
Delaware	x[4]	x					
Florida		x	x	x	x		
Georgia	x[5]	x	x	x			
Idaho		x		x			
Illinois	x	x	x	x	x		x[6]
Indiana	x[7]	x		x			
Iowa	x	x	x	x	x		
Kansas		x					
Kentucky		x		x			
Louisiana		x	x	x	x		
Maine		x		x	x	x	x[8]
Maryland	x[9]	x	x		x		
Massachusetts	x	x		x	x	x	x[10]
Michigan	x	x	x	x			x[11]
Minnesota	x	x	x	x	x	x	
Mississippi		x		x			
Missouri	x	x	x	x	x		
Nebraska	x[12]	x	x	x	x		
New Hampshire	x	x		x		x	
New Jersey	x[13]						x[14]
New Mexico			x	x			
New York		x	x	x			
North Carolina	x	x	x	x	x		x[15]
North Dakota			x	x	x		
Ohio	x[9]	x					
Oregon		x	x	x	x		
Pennsylvania	x[16]	x		x			
Rhode Island[17]	x	x	x	x	x		x[18]
S. Carolina	x	x	x	x	x		
S. Dakota	x	x	x	x	x		
Tennessee		x	x	x			
Texas		x	x	x	x[19]		
Utah		x	x	x			
Vermont		x	x	x	x		x[20]
Virginia		x		x			
West Virginia[21]	x[22]	x	x	x			
Wisconsin	x	x	x	x	x	x[23]	x[18]
Wyoming				x			

[1]Regulations banning disposal of all computer and electronic equipment in landfills began January 1, 2008; [2]Fluorescent bulbs; [3]Grass clippings; [4]Yard waste ban at Cherry Island Landfill began in January 2008; [5]Yard trimmings are banned from MSW landfills designed and built to Subtitle D standards; Primary method of dealing with yard trimmings is disposal in inert and C&D landfills in state; [6]Potentially Infectious Medical Waste; [7]Leaves; also, woody vegetative matter greater than 3 feet in length is banned by statute; woody vegetative matter less than 3 ft in length is banned if it is not bagged, bundled, or otherwise contained; [8]Mercury containing products; [9]Separately collected yard waste is banned; [10]Glass, metal and plastic containers and recycled paper; Asphalt paving, brick, concrete, metal and wood were banned from disposal in July 2006; [11]Beverage containers; [12]Leaves and grass are banned April 1 through November 30; [13]Leaves only; [14]All other recyclable materials that any local government designates as a recyclable material; [15]Aluminum cans banned since 1994; beginning in 2009, wood pallets, plastic bottles and oil filters will be banned; Beginning in 2012, computers will no longer be accepted for disposal; [16]Truckloads comprised primarily of leaves; [17]All materials specified as mandatory recyclables are technically banned from landfill disposal; [18]Recyclable paper and containers; [19]With CFCs; [20]Oil based paint, mercury added products, ni-cad batteries; [21]Items checked are banned by state but individual landfills may have own rules; [22]West Virginia has a ban on yard waste; if no composting facility is available, landfills can usually get a waiver on the rule; [23]Generated by non-households.

Figure 2: MSW landfill disposal bans for selected materials (Arsova et al., 2008). Notes: (1) most of these bans pertain to landfilling, but they may influence composition of waste destined for combustors as well; (2) state regulations may have changed since the date of publication of this table.

The level of recovery through recycling programs can also influence the composition of MSW. Paper components such as newspaper, cardboard, office paper, and mixed paper types are collected through recycling programs, often at a high rate of recovery. The recovery rate (i.e., the quantity of materials recovered for recycling as a percentage of total waste generated, not including any losses or contamination of recyclables), of municipal recycling systems is variable on a municipal/county level as well as by state, as shown by Figure 3. The rates depend upon a number of technical and non-technical factors, including the type of recycling system (e.g., single-stream versus dual-stream curbside collection), the age of the program (i.e., how long it has been established), the level of public outreach, municipal policies such as variable-rate waste collection (also known as Pay As You Throw, or PAYT), frequency of collection, and demographics (e.g., recovery rates are correlated with median household income). Other practices, such as the level of backyard composting in a region, can also affect the recovery rate of materials in certain communities (EPA 2008, p. 21). Recovery of paper, yard trimmings, and other materials will influence the carbon content and ratio of fossil-to-biogenic components of MSW sent to MWCs for combustion, and, consequently, the resulting CO_2 emissions.

Figure 4 provides data on of the range of geographic variability in the MSW stream by summarizing state-level MSW-sort data (i.e., the composition of MSW after recovery from recycling programs). The figure illustrates that paper and organics (i.e., food waste and yard trimmings) components in particular exhibit a high level of variability, fluctuating by nearly 20 percent (as a fraction of total MSW wet weight) across different states. Plastics have been observed to constitute from 6 (in Kansas) to 18 percent (in Iowa) of the MSW stream. The data reveal that there is significant geographic variability in the composition of MSW, particularly the fractions that contribute to fossil and biogenic CO_2 emissions.

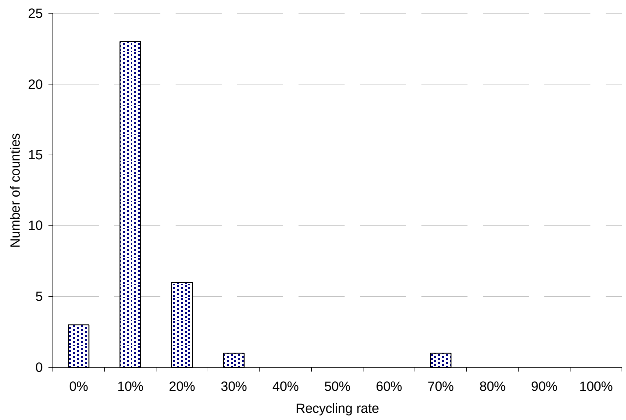
Seasonal variability

The composition of MSW varies seasonally, according to variations in climate as well as economic and demographic waste generation factors each year (EPA 2008, p. 21). Examples of factors that contribute to seasonal variability in the composition of MSW—yard trimmings in particular—include the following trends:

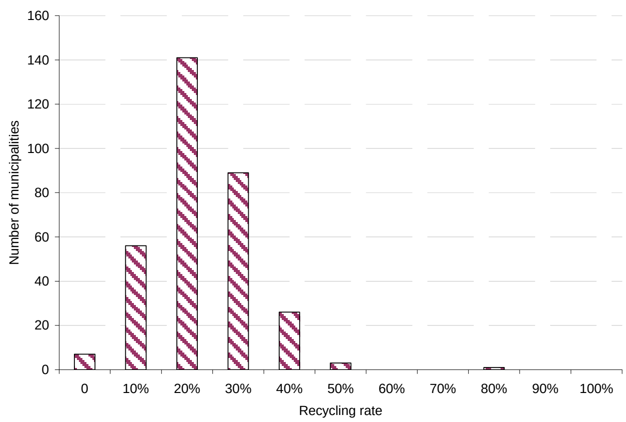
- Increased generation of grass clippings in spring, summer, and fall months (and in most climates, no generation in the winter),
- The occurrence of autumn leaves (September/October/November) in areas with deciduous forests and urban trees, and
- Generation of Christmas tree and wrapping paper waste in December/January.

Local and/or state policies may also have an impact on the level of seasonal variation in MSW composition. Since many states ban yard trimmings, autumn leaves, and Christmas trees from the MSW stream (see Figure 2), the level of seasonal variation in the generation of yard trimmings will be less in these jurisdictions.

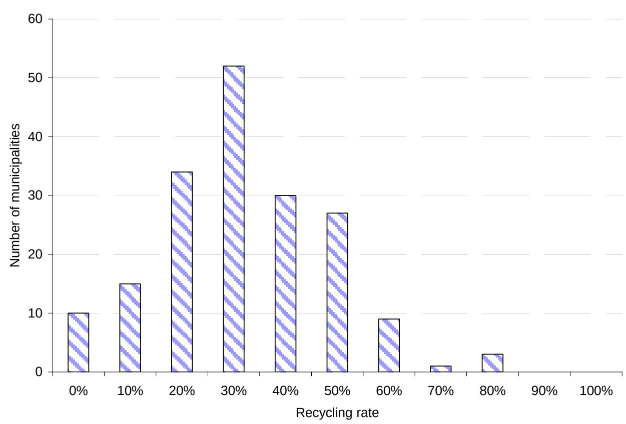
MWCs have limited ability to even out the seasonal variation since it is generally not feasible to store MSW for more than a few days prior to combustion (due to odor and hygiene concerns). Consequently, the underlying seasonal variation in MSW that fuels MWCs will translate to seasonal variation in CO_2 emissions as well.



(a) New Mexico



(b) Massachusetts



(c) New Hampshire

Figure 3: Distribution of recovery rates across counties and municipalities using different recycling programs in (a) New Mexico, (b) Massachusetts, and (c) New Hampshire. Note: The vertical axes differ in scale.

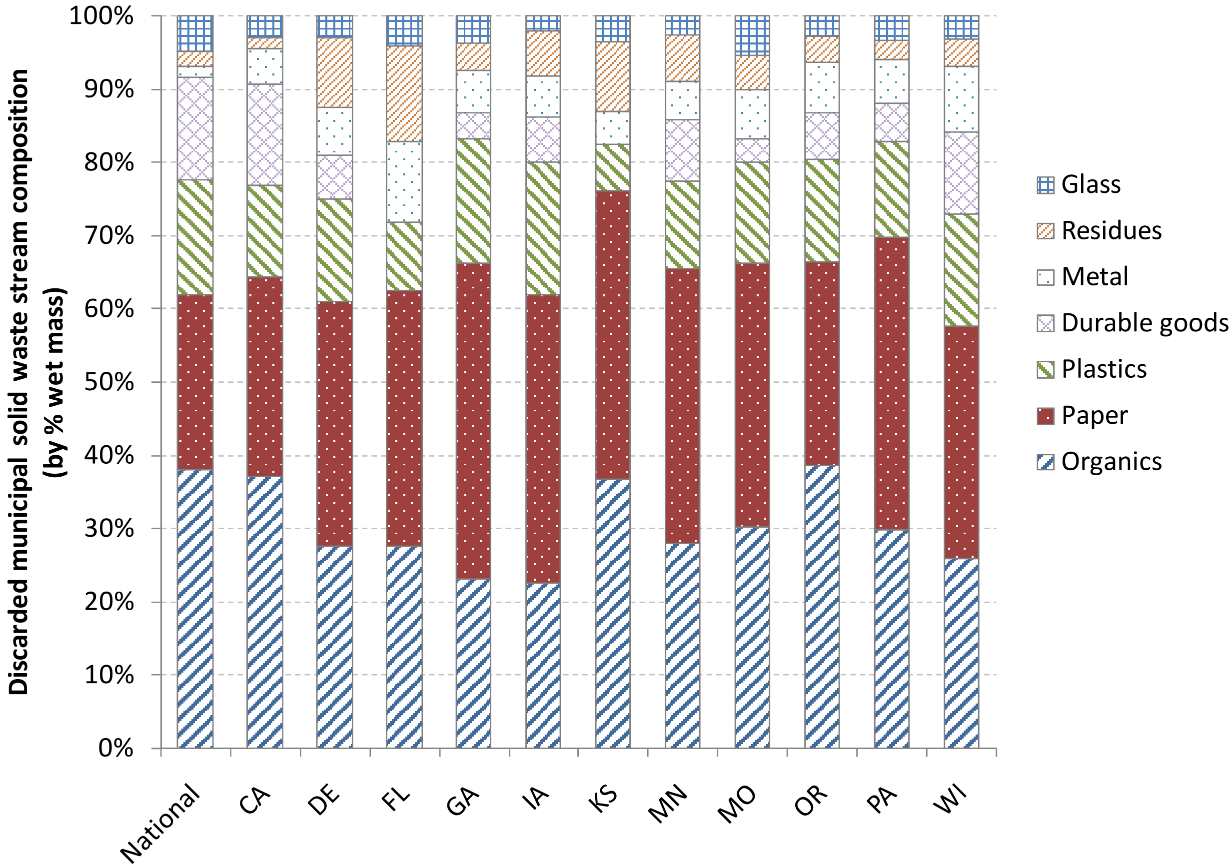


Figure 4: Variation in composition of discarded MSW streams by state (Staley & Barlaz, 2009). Paper and organics (composed of yard trimmings and food scraps) result in biogenic CO_2 emissions when combusted, while plastics result in fossil CO_2 emissions. Glass and metal fractions are not combustible and do not result in CO_2 emissions. Durables include appliances/electronics, carpets, and other miscellaneous/bulky items, and residues include other unspecified waste fractions; these categories may also contain materials that generate fossil or biogenic CO_2 emissions in MWCs.

Long-term compositional trends

Long-term changes in MSW composition also contribute to variability in the MSW stream. Over time, the types of materials entering the MSW stream are changing to reflect patterns of production, consumption, and waste generation in the United States.

For example, the U.S. Energy Information Administration (EIA) has studied energy generation from fossil and biogenic wastes in MSW. They found two trends in the composition of the MSW stream from 1989 to 2007: first, the heat content (BTUs per pound) of MSW has increased, and second, the fossil fraction of MSW has increased relative to the biogenic fraction (EIA 2007). Table 3 and Figure 5 shows how the fossil fraction of MSW has increased relative to the biogenic share on a heat-content basis from 1989 to 2005 within the United States. EIA attributes this trend to “more plastics being discarded at the same time that decreasing amounts of paper and paper products are entering the waste stream” (EIA 2007, p. 5).

The estimates developed by EIA highlight the effect that long-term compositional trends can have on CO_2 emissions from MSW combustion. Changes in the heat content and ratio of fossil to biogenic components of MSW will influence both the carbon content of MSW combusted as fuel as well as the fossil-to-biogenic ratio of CO_2 emissions.

Table 3: MSW heat content and biogenic/fossil shares from 1989 to 2005 (EIA 2007, p. 6)

Year	Heat Content (Million Btu/Ton)	Shares of Total MSW Energy	
		Biogenic	Non-Biogenic
1989	10.08	0.67	0.33
1990	10.21	0.66	0.34
1991	10.40	0.65	0.35
1992	10.61	0.64	0.36
1993	10.94	0.64	0.36
1994	11.15	0.63	0.37
1995	11.11	0.62	0.38
1996	10.94	0.61	0.39
1997	11.17	0.60	0.40
1998	11.06	0.60	0.40
1999	10.95	0.60	0.40
2000	11.33	0.58	0.42
2001	11.21	0.57	0.43
2002	11.19	0.56	0.44
2003	11.17	0.55	0.45
2004	11.45	0.55	0.45
2005	11.73	0.56	0.44

Note: Years in bold are EPA data collection years. Non-bolded years have been linearly interpolated at the materials group level between immediately surrounding bolded years.
Sources: Heat Content (Million Btu/ton) is derived from Environmental Protection Agency, *Municipal Solid Waste in the United States: 2005 Facts and Figures*, Table 4. http://www.epa.gov/msw/msw99.htm
Biogenic and non-biogenic percentages are EIA estimates.

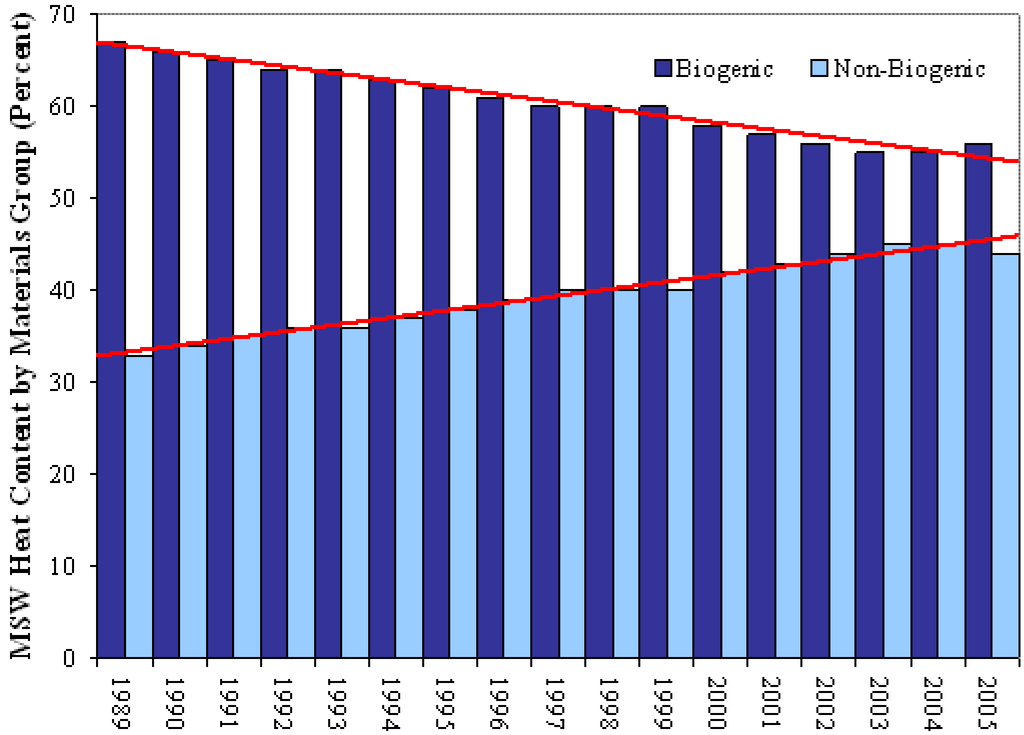


Figure 5: Trends in fossil and biogenic fractions of MSW on a heat-content basis (EIA 2007)

* * * * * * *

In sum, the composition of MSW is very heterogeneous – containing thousands of individual materials and over a dozen different categories of materials – and extremely variable on a geographic and temporal basis. This underlying variability in the composition of the fuel of MWCs implies that accurate monitoring requires frequent sampling, and an approach to either characterize the fossil and biogenic components of the fuel or, more directly, of the emissions themselves.

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Default Biomass Fraction for Municipal Solid Waste and Tires

EPA has amended 40 CFR 98.33(e)(3) to add an alternative calculation methodology for biogenic CO_2 emissions from the combustion of tires and/or MSW that may be used when the total contribution of these fuels to the unit's heat input is 10 percent or less. The methodology may also be used for small, batch incinerators that burn no more than 1,000 tons of MSW per year. Units that qualify for and elect to use the methodology use Tier 1 to calculate the total annual CO_2 emissions from the combustion of the MSW or tires, and multiply the result by an appropriate default factor that represents the biomass fraction of the fuel, to obtain an estimate of the annual biogenic CO_2 emissions. This memo provides the underlying data used to generate the default factors of 0.20 for tires and 0.60 for MSW that is found in the rule.

MSW

See Table 3 in the previous section: **"***Heterogeneity and Variability of Municipal Solid Waste in Relation to Municipal Waste Combustor Emissions"***.** The default factor of 0.60 is the average biogenic fraction of MSW during the time series from 1989 through 2005.

2. Tires

The default value for tires was based on data available from the Rubber Manufacturers Association (RMA). According to RMA the typical composition of tires is different depending on if it is a passenger tire or a truck tire. The characteristics are presented below. The default factor of 0.20 is the average biogenic fraction of passenger and truck tires.

Passenger Tire			**Truck Tire**	
Natural rubber	14 %		Natural rubber	27 %
Synthetic rubber	27%		Synthetic rubber	14%
Carbon black	28%		Carbon black	28%
Steel	14 - 15%		Steel	14 - 15%
Fabric, fillers, accelerators, antiozonants, etc.	16 - 17%		Fabric, fillers, accelerators, antiozonants, etc.	16 - 17%
Average weight:	New 25 lbs, Scrap 22.5 lbs.		Average weight:	New 120 lbs., Scrap 110 lbs.

Source: Rubber Manufacturers Association.
http://www.rma.org/scrap_tires/scrap_tire_markets/scrap_tire_characteristics/

Comparison of 250 Tons of MSW Per Day And 250 MMBtu/hr Heat Input Capacity

Background and Summary[6]

MSW is a fuel for MWCs, which are a category of stationary combustion sources covered under Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule. Subpart C requires stationary combustion sources to report their carbon dioxide emissions and establishes four tiers of methods for stationary combustion sources to calculate or physically measure their carbon dioxide emissions.

According to sections 40 CFR § 98.33(b)(4)(ii)(A), stationary combustion units with a "maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste […] a maximum rated input capacity greater than 250 [short] tons per day of MSW" that meet the other five conditions in paragraphs (b)(4)(ii)(B) through (b)(4)(ii)(F) must use the Tier 4 Calculation Methodology to calculate their carbon dioxide emissions. Some owners and operators of MWCs contended that the threshold of 250 short tons per day of MSW is more stringent than the 250 mmBtu/hr heat input threshold for other stationary combustion units, and therefore places a disproportionate burden on MWCs.

This memorandum evaluates approximate equivalencies between the 250 short tons of MSW per day threshold for units combusting MSW and the 250 mmBtu/hour heat input capacity threshold for other stationary combustion units. The calculation and relevant data are provided below.

Calculation and Data Sources

The formula for converting the maximum rated heat input capacity of a MWC unit in short tons per day into an equivalent maximum rated heat input capacity can be expressed as follows:

*MSW input rate [short tons/day] * MSW heating value [mmBtu/short ton] ÷ N [hours/day]= Heat input rate [mmBtu/hour]*

Where,

MSW input rate = the maximum rated input capacity of the unit, in short tons per day
MSW heating value = the heat rate of MSW, in mmBtu per short ton
N = the time period over which MWC operation is evaluated in a day to determine maximum rated input capacity, in hours per day
Heat input rate = the maximum rated heat input capacity of the unit, in mmBtu per hour

To evaluate the equivalent heat input capacity at rates of 250 short tons/day and 250 short tons/day, two parameters are required: (i) the heating value of MSW combusted in MWCs, and (ii) the number of hours per day over which MWC operation is evaluated to determine maximum rated input capacity.

Heating value of MSW Combusted in MWCs

[6] Developed with support from Christopher Evans and Randy Freed, ICF International.

Estimates of the heating value of MSW are given in Table 4. Due to the considerable heterogeneity of MSW, heating value estimates range from 4,500 to 5,865 Btu/pound, or 9.0 to 11.7 mmBtu/short ton. This range reflects the variability in MSW composition resulting from geographic variability, seasonal patterns in MSW disposal, and long-term trends in MSW generation.

Table 4: Heating value for estimates for MSW

Heating value of MSW		**Notes**	**Source**
Btu/pound	mmBtu/short ton		
4,500	9.00	MSW that is not refuse-derived fuel	EPA (1996), p. 2.1-29
5,500	11.00	MSW refuse-derived fuel	EPA (1996), p. 2.1-29
5,040	10.08	Heating value of MSW in 1989; based on estimates of material-specific heating values and U.S. MSW composition taken from EPA (2006) Facts and Figures: 2005.	EIA (2007), Table 1, p. 6
5,865	11.73	Heating value of MSW in 2005; based on estimates of material-specific heating values and U.S. MSW composition taken from EPA (2006) Facts and Figures: 2005.	EIA (2007), Table 1, p. 6

Number of Hours Per Day Over Which MWC Operation is Evaluated to Determine Maximum Rated Input Capacity

Second, according to 40 CFR § 60.58b(j), the maximum rated input capacity of MWCs is evaluated over a 24-hour period (i.e., N = 24), regardless of whether the MWC operates continuously or as a batch-feed operation. The procedures for calculating MWC unit capacity are defined as follows:

- For MWC units that are capable of combusting MSW continuously for a 24-hour period, “the unit capacity shall be calculated based on 24 hours of operation at the maximum charging rate”, where the maximum charging rate is either:
    - The maximum design heat input capacity of the unit multiplied by a heating value for the MSW fuel combusted, for combustors designed based on heat capacity, or
    - The maximum design charging rate, for combustors not designed based on heat capacity.

- For batch-feed MWC units, unit capacity is calculated “as the maximum design amount of municipal solid waste that can be charged per batch multiplied by the maximum number of batches that could be processed in a 24-hour period.”

40 CFR § 60.58b(j) also specifies that the MSW heating values to convert the design heat input capacity of a MWC into the unit’s input capacity shall be “12,800 kilojoules per kilogram for combustors firing refuse-derived fuel and […] 10,500 kilojoules per kilogram for combustors

firing municipal solid waste that is not refuse-derived fuel". These values correspond to MSW heat rates of 9.0 and 11.0 mmBtu/short ton respectively, consistent with the EPA (1996) values from AP-42, identified in Table 4.

Results

Table 5 provides the equivalent maximum rated heat input capacities for two different MWC unit rated input capacities using the equation and parameters provided above. Due to the variability in MSW heating values, we selected three MSW heat input values: a low value of 9 mmBtu/short ton; a medium value of 10 mmBtu/short ton, and a high value of 12 mmBtu/short ton. This range is representative of the values provided by Table 4 above, and in 40 CFR § 60.58b(j).

Table 5: Equivalent maximum rated heat input capacity at various MSW heat input rates for two different MWC rated input capacities

Max. rated input capacity (short tons/day)	**Equivalent maximum rated heat input capacity (mmBtu/hour)**		
	Low MSW heat input (9 mmBtu/short ton)	Medium MSW heat input (10 mmBtu/short ton)	High MSW heat input (12 mmBtu/short ton)
250	94	104	122
600	225	250	**300**

Notes: Calculated over a 24-hour operating period (i.e., N = 24 hours/day)
Gray = below 250 mmBtu/hr threshold for other stationary combustion units
Black = equal to 250 mmBtu/hr threshold for other stationary combustion units
Bold = above 250 mmBtu/hr threshold for other stationary combustion units

The 250 short tons/day input capacity threshold is more stringent than the 250 mmBtu/short ton heat input capacity threshold, regardless of the MSW heating value. Using the medium MSW heat input value of 10 mmBtu/short ton, a threshold of 600 short tons of MSW per day is equivalent to the 250 mmBtu/hour threshold that applies to other stationary sources. MWCs that combust MSW with heating values higher than 10 mmBtu/short ton will have a higher equivalent maximum rated heat input capacity; MWCs that combust MSW with heating values lower than 10 mmBtu/short ton will have a lower equivalent maximum rated heat input capacity.

Conclusion

Acknowledging the variability in MSW composition and heat content, a threshold of 600 short tons of MSW per day is consistent with the 250 mmBtu/hour threshold that applies to other stationary combustion units for Tier 4 reporting in 40 CFR § 98.33(b)(4)(ii).

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Subpart C and D

Part 75 Units that Combust Biomass (Results of Database Query)

On August 24, 2010, a query of the CAMD database was performed, to identify units in Part 75 monitoring and reporting programs (i.e., Acid Rain, CAIR, RGGI, NOx SIP Call) that combust biomass and/or partially biogenic fuels such as municipal solid waste (MSW) and tire-derived fuel (TDF), either as the primary fuel or as a secondary fuel. For each unit, the query also provided the unit's reporting frequency (i.e., year-round or ozone season-only), its Part 75 heat input methodology, and (if applicable) its CO2 mass emissions methodology.

The objective of the query was to find out how many Part 75 units that burn biomass or partly biogenic fuels would qualify to use a recently-proposed Greenhouse gas (GHG) emissions reporting option under 40 CFR Part 98[7]. That option would allow Part 75 units to report only the total annual CO2 mass emissions in their Part 98 GHG emissions reports, instead of separately reporting biogenic CO2 and non-biogenic CO2 emissions.

To qualify for the optional biogenic CO2 reporting, a unit that combusts biomass or partly biogenic fuel(s) would either have to be: (1) an Acid Rain Program (ARP) unit; (2) a RGGI Program unit; or (3) a CAIR unit (or NOx SIP Call unit) that is not in ARP or RGGI, and that reports heat input data (but not CO2 mass emissions data) to EPA year-round using Part 75 methods. Units in Categories (1) and (2) are subject to Subpart D of Part 98. Units in Category (3) fall under §98.33(a)(5) of Subpart C. Many units are in more than one Part 75 program.

The results of the query showed that there are **53** units in Part 75 programs that combust biomass or partly biogenic fuel. **Ten** of these units would not qualify for optional biogenic CO2 reporting at the present time, because they are subject only to the CAIR Ozone Season Program, and report heat input data to EPA on an ozone season-only basis, rather than year-round---however, these 10 units could qualify in subsequent years if they were to switch to year-round reporting. The status of **three** other units that combust refuse (MSW) as a secondary fuel is questionable, because units that combust MSW are required by Part 98 to quantify biogenic CO2 emissions (see §98.33(e)(3))[8]. By means of a phone call to one of the facilities on the list[9], we have learned that there is a fourth Part 75 unit that burns MSW as a backup fuel. Finally, one unit identified by the query was eliminated from further consideration because it combusts coal refuse, not municipal solid waste (the monitoring plan was incorrectly coded).

[7] See the proposed revisions to §§98.3(c), 98.33, and 98.36(d) in the August 11, 2010 Federal Register notice (75 FR 48744-48814).

[8] These three units are included as candidates for the optional biogenic CO2 reporting only because they are subject to Part 75. Note, however, that if the proposal to make biogenic CO2 emissions reporting optional is finalized, the rule would become internally inconsistent, because §98.33(e)(3) would require Part 75 units that combust MSW to quantify biogenic CO2, but the new rule provision would not require the facility to report biogenic CO2 emissions separately.

[9] August 25, 2010 telephone call from Robert Vollaro of CAMD to Donald Kom of the City of Ames, IA

This means that to the best of our knowledge, there are an estimated **43** Part 75 units that could presently qualify for the proposed optional biogenic CO2 reporting under Part 98. The adjusted results of the query are presented in Table 1, below. The 10 units that could not currently qualify for the optional reporting, but may be able to qualify in future years, are shown in Table 2, below. Biomass fuels and partly biogenic fuels are highlighted in yellow in Tables 1 and 2.

Table 1: Part 75 Units that Would Presently Qualify for Optional Biogenic CO2 Reporting

Primary fuel	Secondary fuel	Number of Units	Unit Type	
			EGU	Non-EGU
Coal	TDF	17	17	-
Coal	Wood	8	6	2
Wood	Natural Gas	7	7	-
Coal	Municipal Solid Waste	4	3	1
Wood	-------	2	2	-
TDF	-------	1	1	-
Coal	Process Sludge	1	-	1
Wood	Other Solid Fuel	1	1	-
Wood	Coal	1	1	-
Residual Oil	Wood	1	-	1

Table 2: Part 75 Units that May Qualify for Optional Biogenic CO2 Reporting in Future Years

Primary fuel	Secondary fuel	Number of Units	Unit Type	
			EGU	Non-EGU
Coal	Wood	5	1	4
Wood	Coal	2	2	-
TDF	LPG	2	2	-
Coal	Process Sludge	1	-	1

Table 1 shows that twelve (12) of the qualifying units combust biomass or partly biogenic fuel as the primary fuel. For 11 of these 12 units, wood is the primary fuel, and for the other unit, TDF is the primary fuel. Nine of the 12 units combust secondary fuels (seven of them burn natural gas, one burns coal, and one burns "other" solid fuel). Three of the units (two wood-fired units and one TDF-fired unit) list no secondary fuels.

For the remaining 31 units in Table 1, 30 of them combust coal as the primary fuel and one unit combusts residual oil. All 31 of the units burn biomass or partly biogenic fuel as a secondary fuel---17 of them burn TDF, 9 of them burn wood, 4 of them burn MSW, and one paper mill unit combusts process sludge.

Thirty eight (38) of the 43 units in Table 1 are electricity generating units (EGUs) and the other 5 are non-EGUs. Four (4) of the 5 non-EGUs are located at pulp and paper manufacturing facilities.

For all the results from the database query, please see the data entry to docket EPA-HQ-OAR-2008-0508 titled List_of_Part_75_units_that_combust_biomass.

Results

The results of the CAMD database query show that a relatively significant number of Part 75 units (43) would qualify for optional biogenic CO2 emissions reporting under the August 11, 2010 proposed revisions to Part 98. Twelve (12) of these units combust wood or TDF as the primary fuel, and the other 31 units combust a variety of biogenic or partly biogenic fuels (i.e., wood, TDF, MSW, process sludge) as secondary fuels. Ten other Part 75 units that report emissions data to EPA on an ozone season-only basis could not qualify for the optional biogenic CO2 reporting at the present time, but could qualify in future years by switching to year-round reporting.

Subpart X and Y

Evaluation of Process Heaters Less than 30 MMBtu/hr Rated Heat Capacity

I. Purpose[10]

The purpose of this memorandum is to document the evaluation of process heaters that have a rated heat capacity of less than 30 million British thermal units per hour (MMBtu/hr).

II. Summary of Findings

Small process heaters (those with rated heat capacity less than 30 MMBtu/hr) are generally not subject to Federal or consent decree emission limits and therefore are not typically required to monitor fuel gas usage at the individual process heater or boiler. These small process heaters are expected to contribute less than 5 percent of the stationary combustion source emissions.

III. Background

The U. S. Environmental Protection Agency (EPA) finalized mandatory greenhouse gas (GHG) reporting requirements on October 30, 2009 (74 FR 56260), which requires petroleum refineries to use Tier 3 calculation and monitoring methods for stationary combustion sources that combust fuel gas. EPA received feedback from stakeholders seeking relief from the Tier 3 monitoring requirements for small combustion sources.

IV. Approach and Discussion of Results

Available information regarding existing monitoring requirements for small stationary combustion sources at petroleum refineries was reviewed. Attachment 1 presents a summary of consent decree requirements. As shown in the Attachment 1, requirements for nitrogen oxide (NO_X) from process heaters generally apply to process heaters greater than 40 MMBtu/hr. Similarly, review of NO_X emission limits in 40 CFR 60 subpart Ja and in South Coast Air Quality Management District (AQMD) Rule 1109 indicate that these rules apply to process heaters greater than 40 MMBtu/hr. 40 CFR 60 subpart Dc specifically addresses sulfur dioxide (SO2) and particulate matter (PM) emissions from steam generating units from 10 to 100 MMBtu/hr rated heat capacity. The PM emission standards, however, apply only to units that combust coal (alone or in combination with other fuels) in units with rated heat capacities of 30 MMBtu/hr or greater. While the SO_2 standards apply to smaller units, compliance with the SO_2 standards is expected to be assessed from hydrogen sulfide (H_2S) or total sulfur monitoring in the fuel gas mix drum rather than at the individual combustion unit. Thus, it appears likely that most process heaters less than 30 MMBtu rated input heat capacity are not typically required to monitor fuel gas usage at the individual process heater or boiler.

The distribution of process heaters were estimated based on facility-specific processing unit capacities (EIA, 2006) and fuel use factors used previously to project GHG emissions by

[10] Developed with support from Jeff Coburn, RTI International.

petroleum refinery (Coburn, 2007). Based on these factors, the cumulative process heater capacity for all U.S. refineries is estimated to be 257,831 MMBtu/hr. The cumulative sum of the process heater capacities projected to be 30 MM Btu/hr or greater based on the EIA reported process capacities is 253,796 MMBtu/hr or over 98 percent of the nationwide capacity. We note that the EIA processing capacities are reported for the refinery. In some cases, there may be two or more processing units of the same type at the refinery, so that the individual process heater sizes projected from the EIA processing capacities will be overstated if there are multiple units at the refinery. Assuming every unit has two process heaters (or that each facility has two units for each type of processing unit listed in EIA), the cumulative sum of the process heater capacities projected to be 30 MM Btu/hr or greater is 245,996 MMBtu/hr or approximately 95 percent of the nationwide capacity. As it is anticipated that the larger facilities are more likely to have either multiple equipment trains or multiple process heaters for a given process unit, the actual fuel use for process heaters with rated heat capacities of 30 MMBtu/hr or more is expected to be somewhere between these two estimates; however, in both scenarios, process heaters with rated heat capacities less than 30 MMBtu/hr are projected to contribute less than 5 percent of the nationwide fuel use.

V. References

Coburn J. 2007. *Greenhouse Gas Industry Profile for the Petroleum Refining Industry*. Prepared for U.S. Environmental Protection Agency, Washington, DC. Contract No. GS-10F-0283K. June 11.

EIA (Energy Information Administration). 2006. *Refinery Capacity Report 2006.* Prepared by the Energy Information Administration, Washington, DC. June 15.

Lion Oil Co. – El Dorado, AR				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install low-NOx burners or alternate technology	0.045 lb/MMBtu for atmospheric heater	(8-year program – see Appendix C)
Heaters and boilers	CO	BACT analysis, install controls and comply with EPA-established limits		Analysis - 4/30/03 Controls – 12/31/04
Heaters and boilers	SO2	Comply with subpart J; limit H2S in refinery fuel gas		CEMS by 12/31/06

BP (formerly Atlantic Richfield Co. (ARCO)) – Carson, CA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		1/18/05
Heaters and boilers		Subject to subparts A & J as those subparts apply to fuel gas combustion devices		Date of entry

Chevron USA Products Co. – El Segundo, CA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Controlled H/B (SCR, low-NOx burners, shut down, etc.) must represent 30% of the total heat input capacity of H/B greater than 40 MMBtu/hr	0.040 lbs/MMBtu	6/30/11
Heaters and boilers	SO2	Affected facility under subpart J; eliminate fuel oil burning		Date of entry

Chevron USA Products Co. – Richmond, CA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Controlled H/B (SCR, low-NOx burners, shut down, etc.) must represent 30% of the total heat input capacity of H/B greater than 40 MMBtu/hr	0.040 lbs/MMBtu	6/30/11

Chevron USA Products Co. – Richmond, CA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Affected facility under subpart J; eliminate fuel oil burning		Date of entry

ConocoPhillips (formerly Tosco, formerly Unocal Corp.) – Carson (LAR), CA				
Heaters and boilers	SO2	Affected facilities under subpart J		3/31/05
Heaters and boilers	SO2	Comply with 40 C.F.R. §60.104(a)(1)		Date of lodging

ConocoPhillips (formerly Tosco, formerly Unocal Corp.) – Wilmington (LA), CA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Affected facilities under subpart J		3/31/05
Heaters and boilers	SO2	Comply with 40 C.F.R. §60.104(a)(1)		Date of lodging

ConocoPhillips (formerly Tosco, formerly Unocal Corp.) – Rodeo (SF), CA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Affected facilities under subpart J		Date of lodging

ConocoPhillips (formerly Tosco, formerly Unocal Corp.) – Santa Maria (SF), CA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Affected facilities under subpart J		Date of lodging
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/06

Valero (formerly Ultramar Diamond Shamrock) – Wilmington, CA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05

Valero (formerly Ultramar Diamond Shamrock) – Wilmington, CA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/07

Valero (formerly Exxon Co. USA) – Benicia, CA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/07

Suncor Energy (formerly Conoco Inc.) – Commerce City (Denver), CO				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install NOx controls on at least 30% of the heater capacity greater than 40 MMBtu/hr		7/31/09
Heater H-27		Affected facility under subpart J		12/31/06
Heaters and boilers	SO2, PM, CO	Affected facilities under subpart J		Date of lodging
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.005 lb/MMBtu (365-day avg.); 0.010 lb/MMBtu (24-hr avg.)	Date refinery applies for PAL
Heaters and boilers	CO	Comply with emission limit when NOx controls are added or if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb/MMBtu (365-day avg.); 0.060 lb/MMBtu (24-hr avg.)	Date of NOx control installation or Date refinery applies for PAL
Heaters and boilers	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu (365-day avg.) OR 125 ppmvd H2S in fuel gas (365-day avg.)	Date refinery applies for PAL

Valero Energy (formerly Ultramar Diamond Shamrock, formerly Total Petroleum) – Denver (Commerce City), CO				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/07

Citgo Petroleum – Savannah, GA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers combusting refinery fuel gas	SO2	Affected facility under subpart J		Date of entry
FCCU heater	NOx	Install controls (SCR, low-NOx burners, etc.) or shut down	0.040 lbs/MMBtu	12/31/08
Heaters and boilers	SO2	Affected facility under subpart J		Date of entry

Tesoro Hawaii Petrol. (formerly BHP) – Kapolei, HI				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		6/30/11
Heaters and boilers that combust refinery fuel gas	SO2	Affected facility under subpart J		Date of entry

Marathon Ashland Petrol. – Robinson, IL				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2, PM	Affected facilities under subpart J		Date of entry (8/30/01)
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.010 lb/MMBtu (24-hr avg.), 0.005 lb/MMBtu (365-day avg.)	Date of application for the PAL
Heaters and boilers that burn fuel gas only	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu or 125 ppmvd H2S in fuel gas (365-day avg.)	Date of application for the PAL

Premcor Refining Group (formerly Clark Oil and Refining Corp.) – Hartford, IL				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Combination of current and new generation ultra low-NOx burners and low NOx burners	Design to achieve between 0.012 and 0.06 lb/MMBtu	10/1/05
Heaters and boilers	SOx and NOx	Discontinue burning of fuel oil		30 days after Date of entry
Heaters and boilers		Affected sources under subpart J		Date of entry

ConocoPhillips (formerly Tosco Refining, Equilon, Wood River, & Shell Oil) – Wood River (Roxana), IL				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers (Distilling West)	SO2	Affected facilities under subpart J		Date of lodging
Heaters and boilers (except Distilling West)	SO2	Affected facilities under subpart J		6/30/08

BP (formerly Amoco Oil Co.) – Whiting, IN				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		1/18/05
Heaters and boilers	SO2	Eliminate fuel oil burning		6/01/03
Heaters and boilers		Subject to subparts A & J as those subparts apply to fuel gas combustion devices		12/31/01

National Cooperative Refinery Association – McPherson, KS				
Unit	Pollutant	Requirement	Emission limit	Deadline
Boilers SB-016 and SB-018	NOx	Comply with emission limit	101.9 tons/yr (12-month avg.) (both boilers combined)	Date of lodging
Distillate hydrotreater feeder & platformer heater	H2S	Comply with H2S concentration limit in fuel gas	5 gr/100 scf (365-day avg.)	30 days after Date of entry

Marathon Ashland Petroleum LLC (formerly Ashland, Inc.) – Catlettsburg, KY				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2, PM	Affected facilities under subpart J		Date of entry (8/30/01)
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.010 lb/MMBtu (24-hr avg.), 0.005 lb/MMBtu (365-day avg.)	Date of application for the PAL
Heaters and boilers that burn fuel gas only	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu or 125 ppmvd H2S in fuel gas (365-day avg.)	Date of application for the PAL

Citgo Petroleum Corp. – Lake Charles, LA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		6/30/11
Heaters and boilers that combust refinery fuel gas	SO2	Affected facility under subpart J		Date of entry

ConocoPhillips (formerly Conoco Inc.) – Westlake (Lake Charles), LA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install NOx controls on at least 30% of the heater capacity greater than 40 MMBtu/hr		7/31/09
Heaters and boilers	SO2, PM, CO	Affected facilities under subpart J		Date of lodging
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.005 lb/MMBtu (365-day avg.); 0.010 lb/MMBtu (24-hr avg.)	Date refinery applies for PAL
Heaters and boilers	CO	Comply with emission limit when NOx controls are added or if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb/MMBtu (365-day avg.); 0.060 lb/MMBtu (24-hr avg.)	Date of NOx control installation or Date refinery applies for PAL
Heaters and boilers	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu (365-day avg.) OR 125 ppmvd H2S in fuel gas (365-day avg.)	Date refinery applies for PAL

Marathon Ashland Petroleum LLC – Garyville, LA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		12/31/08
Heaters and boilers	CO	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.060 lb/MMBtu (24-hr avg.), 0.040 lb/MMBtu (365-day avg.)	Date of application for the PAL
Heaters and boilers	SO2, PM	Affected facilities under subpart J		Date of entry (8/30/01)
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.010 lb/MMBtu (24-hr avg.), 0.005 lb/MMBtu (365-day avg.)	Date of application for the PAL

Marathon Ashland Petroleum LLC – Garyville, LA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers that burn fuel gas only	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu or 125 ppmvd H2S in fuel gas (365-day avg.)	Date of application for the PAL

Valero (formerly Orion Refining Corp, formerly TransAmerican Refining Corp) – Norco (St. Charles Parish), LA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/07

ConocoPhillips (formerly, Tosco Refining Co., formerly BP Oil Co.) – Belle Chasse (Alliance), LA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers (except 191-H-1)	SO2	Affected facilities under subpart J		Date of lodging
Heater 191-H-1	SO2	Affected facilities under subpart J		12/31/06

Valero (formerly Basis Petroleum, Inc.) – Krotz Springs, LA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/07

Marathon Ashland Petrol. LLC – Detroit, MI				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		12/31/08

Marathon Ashland Petrol. LLC – Detroit, MI				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	CO	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.060 lb/MMBtu (24-hr avg.), 0.040 lb/MMBtu (365-day avg.)	Date of application for the PAL
Heaters and boilers	SO2, PM	Affected facilities under subpart J		Date of entry (8/30/01)
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.010 lb/MMBtu (24-hr avg.), 0.005 lb/MMBtu (365-day avg.)	Date of application for the PAL
Heaters and boilers that burn fuel gas only	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu or 125 ppmvd H2S in fuel gas (365-day avg.)	Date of application for the PAL

Flint Hills Resources (formerly Koch Refining Co.) – Rosemount (Pine Bend), MN				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install ultra low-NOx burners on heaters and boilers with HHV 40 MMBtu/hr or higher	Design to achieve 0.012 – 0.04 lb/MMBtu	12/31/06
Heaters and boilers		Affected facilities under subpart J (few exceptions)		1/01/01

Marathon Ashland Petroleum LLC (formerly Ashland, Inc.) – St. Paul Park, MN				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		12/31/08
Heaters and boilers	CO	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.060 lb/MMBtu (24-hr avg.), 0.040 lb/MMBtu (365-day avg.)	Date of application for the PAL
Heaters and boilers	SO2, PM	Affected facilities under subpart J		Date of entry (8/30/01)
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.010 lb/MMBtu (24-hr avg.), 0.005 lb/MMBtu (365-day avg.)	Date of application for the PAL
Heaters and boilers that burn fuel gas only	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu or 125 ppmvd H2S in fuel gas (365-day avg.)	Date of application for the PAL

Chevron USA Inc. – Pascagoula, MS				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Controlled H/B (SCR, low-NOx burners, shut down, etc.) must represent 30% of the total heat input capacity of H/B greater than 40 MMBtu/hr	0.040 lbs/MMBtu	6/30/11
Heaters and boilers	SO2	Affected facility under subpart J; eliminate fuel oil burning		Date of entry

Ergon Refining Inc. – Vicksburg, MS				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Affected facilities under subpart J		Date of lodging
Heaters and boilers	SO2	Eliminate fuel oil burning except during natural gas curtailment		Date of lodging

Cenex Harvest States – Laurel, MT				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Shut down or install NOx controls on at least 30% of the heater capacity greater than 40 MMBtu/hr		12/31/11
Heaters and boilers	SO2	Minimize burning of fuel oil		

Conoco Inc. – Billings, MT				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install NOx controls on at least 30% of the heater capacity greater than 40 MMBtu/hr		7/31/09
Heater H-16		Affected facility under subpart J		6/30/03
Heaters and boilers	SO2, PM, CO	Affected facilities under subpart J		Date of lodging
Heaters and boilers	SO2	Comply with emission limit when fuel oil is burned	300 tons/year (365-day avg.)	Date of lodging

Conoco Inc. – Billings, MT				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.005 lb/MMBtu (365-day avg.); 0.010 lb/MMBtu (24-hr avg.)	Date refinery applies for PAL
Heaters and boilers	CO	Comply with emission limit when NOx controls are added or if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb/MMBtu (365-day avg.); 0.060 lb/MMBtu (24-hr avg.)	Date of NOx control installation or Date refinery applies for PAL
Heaters and boilers	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu (365-day avg.) OR 125 ppmvd H2S in fuel gas (365-day avg.)	Date refinery applies for PAL

Montana Refining Co. – Great Falls, MT				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install next generation ultra low NOx burners for any heater or boiler that begins to operate with a heat input capacity of 40 MMBtu/hr or greater		Any time during life of consent decree
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/06
Heaters and boilers	SO2	Eliminate burning of fuel oil (with a few exceptions)		Date of lodging

Citgo Asphalt Refining Co. – Paulsboro, NJ				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers combusting refinery fuel gas	SO2	Affected facility under subpart J		Date of entry

Sunoco (formerly Coastal Eagle Point Oil Co.) – Westville, NJ				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls and accept federally-enforceable emission limits	0.040 lb/MMBtu	3 years

Sunoco (formerly Coastal Eagle Point Oil Co.) – Westville, NJ				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2, PM	Affected facilities under subpart J		Date of lodging
Heaters and boilers	SO2	Eliminate fuel oil burning except during natural gas curtailment		Date of lodging
Boilers 5, 6, 7, and 8	PM-10	Comply with emission limit	0.000427 lbs/MMBtu (1-hr avg.)	Date of entry

ConocoPhillips (formerly Tosco Refining Co., formerly Bayway) – Linden (Bayway), NJ				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers (except selected)	SO2	Affected facilities under subpart J		Date of lodging
Selected heaters and boilers	SO2	Affected facilities under subpart J		6/30/11

Valero Energy Corp. (formerly Mobil Oil) – Paulsboro, NJ				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/08

Navajo Refining Co. – Artesia, NM				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install next generation ultra low NOx burners for all controlled heaters and boilers except Boilers B-7 and B-8		12/31/05 and 12/31/09
Heaters and boilers	SO2	Affected facilities under subpart J		Date of lodging
Heaters and boilers	SO2	Eliminate burning of fuel oil (with a few exceptions)		Date of lodging

Tesoro (formerly BP, formerly Amoco Oil Co.) – Mandan, ND				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		1/18/05
Heaters and boilers	SO2	Eliminate fuel oil burning		3/31/01
Heaters and boilers		Subject to subparts A & J as those subparts apply to fuel gas combustion devices		9/30/03
Heaters and boilers	H2S	Volume-weighted, rolling 3-hour average concentration of H2S in refinery fuel gas	0.10 gr/dscf	12/31/01 until 9/30/03

BP Oil Co. – Toledo, OH				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		1/18/05
Heaters and boilers		Subject to subparts A & J as those subparts apply to fuel gas combustion devices		9/30/03
Heaters and boilers	H2S	Volume-weighted, rolling 3-hour average concentration of H2S in refinery fuel gas	0.10 gr/dscf	12/31/01 until 9/30/03

Marathon Ashland Petroleum LLC (formerly Ashland, Inc.) – Canton, OH				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		12/31/08
Heaters and boilers	CO	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.060 lb/MMBtu (24-hr avg.), 0.040 lb/MMBtu (365-day avg.)	Date of application for the PAL
Heaters and boilers	SO2, PM	Affected facilities under subpart J		Date of entry (8/30/01)
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.010 lb/MMBtu (24-hr avg.), 0.005 lb/MMBtu (365-day avg.)	Date of application for the PAL

Marathon Ashland Petroleum LLC (formerly Ashland, Inc.) – Canton, OH				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers that burn fuel gas only	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu or 125 ppmvd H2S in fuel gas (365-day avg.)	Date of application for the PAL

Sunoco, Inc. – Toledo, OH				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install NOx controls on at least 30% of the heater capacity (all of the capacity greater than 40 MMBtu/hr if less than 30% of total)		8 years after Date of entry
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/09
Heaters and boilers	SO2	Eliminate fuel oil burning (a few exceptions provided)		Date of entry

Conoco Inc. – Ponca City, OK				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install NOx controls on at least 30% of the heater capacity greater than 40 MMBtu/hr		7/31/09
Heaters and boilers	SO2, PM, CO	Affected facilities under subpart J		Date of lodging
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.005 lb/MMBtu (365-day avg.); 0.010 lb/MMBtu (24-hr avg.)	Date refinery applies for PAL
Heaters and boilers	CO	Comply with emission limit when NOx controls are added or if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb/MMBtu (365-day avg.); 0.060 lb/MMBtu (24-hr avg.)	Date of NOx control installation or Date refinery applies for PAL
Heaters and boilers	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu (365-day avg.) OR 125 ppmvd H2S in fuel gas (365-day avg.)	Date refinery applies for PAL

Sunoco, Inc. – Tulsa, OK				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install NOx controls on at least 30% of the heater capacity (all of the capacity greater than 40 MMBtu/hr if less than 30% of total)		8 years after Date of entry
Heaters and boilers	SO2	Affected facilities under subpart J		Date of entry
Heaters and boilers	SO2	Eliminate fuel oil burning (a few exceptions provided)		Date of entry

Valero (formerly Ultramar/Diamond Shamrock, formerly Total Petroleum Inc.) – Ardmore, OK				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/10

Sunoco, Inc. – Marcus Hook, PA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install NOx controls on at least 30% of the heater capacity (all of the capacity greater than 40 MMBtu/hr if less than 30% of total)		6/15/10
Heaters and boilers	SO2	Affected facilities under subpart J		Date of entry
Heaters and boilers	SO2	Eliminate fuel oil burning (a few exceptions provided)		Date of entry (12/31/05 for a few)

Sunoco (combined Sun & Chevron) – Philadelphia (Girard Pt & Pt Breeze), PA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install NOx controls on at least 30% of the heater capacity (all of the capacity greater than 40 MMBtu/hr if less than 30% of total)		6/15/10
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/10
Heaters and boilers	SO2	Eliminate fuel oil burning (a few exceptions provided)		Date of entry (later dates for a few)

ConocoPhillips (formerly Tosco Refining Co., formerly BP) – Trainer (Marcus Hook), PA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Affected facilities under subpart J		6/30/08

BP (formerly Amoco Oil Co.) – Texas City, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		1/18/05
Heaters and boilers		Subject to subparts A & J as those subparts apply to fuel gas combustion devices		Date of entry

Citgo – Corpus Christi, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers (East and West)	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		6/30/11
Heaters and boilers that combust refinery fuel gas	SO2	Affected facility under subpart J		Date of entry

Flint Hills Resources (formerly Koch Petroleum Group, includes SWest Refining) – Corpus Christi, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install ultra low-NOx burners on heaters and boilers with HHV 40 MMBtu/hr or higher	Design to achieve 0.012 – 0.04 lb/MMBtu	12/31/06

Marathon Ashland Petrol. LLC – Texas City, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		12/31/08
Heaters and boilers	CO	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.060 lb/MMBtu (24-hr avg.), 0.040 lb/MMBtu (365-day avg.)	Date of application for the PAL

Marathon Ashland Petrol. LLC – Texas City, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2, PM	Affected facilities under subpart J		Date of entry (8/30/01)
Heaters and boilers	PM	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.010 lb/MMBtu (24-hr avg.), 0.005 lb/MMBtu (365-day avg.)	Date of application for the PAL
Heaters and boilers that burn fuel gas only	SO2	Comply with emission limit if a Plantwide Applicability Limit (PAL) is adopted	0.040 lb SO2/MMBtu or 125 ppmvd H2S in fuel gas (365-day avg.)	Date of application for the PAL

ConocoPhillips (formerly Phillips Petroleum Co.) – Borger, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Affected facilities under subpart J		Date of lodging

ConocoPhillips (formerly Phillips Petroleum Co.) – Sweeny, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Affected facilities under subpart J		6/30/08

Valero (formerly Ultramar/Diamond Shamrock Corp.) – Three Rivers, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/10

Valero (formerly Ultramar/Diamond Shamrock Corp.) – Sunray (McKee), TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/10

Valero Refining Co. – Corpus Christi, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers (East)	SO2	Affected facilities under subpart J		12/31/10
Heaters and boilers (West)	SO2	Affected facilities under subpart J		12/31/07

Valero (formerly Basis Petroleum, Inc.) – Houston, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/07

Valero (formerly Basis Petroleum, Inc.) – Texas City, TX				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Discontinue burning or combustion of fuel oil (during NG curtailment, may burn low sulfur fuel oil)		12/31/05
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/07

Tesoro (formerly BP, formerly Amoco Oil Co.) – Salt Lake City, UT				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		1/18/05
Heaters and boilers	SO2	Eliminate fuel oil burning		6/01/02
Heaters and boilers		Subject to subparts A & J as those subparts apply to fuel gas combustion devices		Date of entry

Chevron USA – Salt Lake City, UT				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Controlled H/B (SCR, low-NOx burners, shut down, etc.) must represent 30% of the total heat input capacity of H/B greater than 40 MMBtu/hr	0.040 lbs/MMBtu	6/30/11
Heaters and boilers	SO2	Affected facility under subpart J; eliminate fuel oil burning except during natural gas curtailment, test runs, or training		Date of entry

Giant Refining (formerly BP, formerly Amoco Oil Co.) – Yorktown, VA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		1/18/05
Heaters and boilers	SO2	Eliminate fuel oil burning		6/01/01
Heaters and boilers		Subject to subparts A & J as those subparts apply to fuel gas combustion devices		Date of entry

BP (formerly Atlantic Richfield Co. (ARCO)) – Ferndale (Cherry Point), WA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install controls on 30% of total heat input capacity of heaters and boilers with capacities greater than 40 MMBtu/hr		1/18/05
Heaters and boilers		Subject to subparts A & J as those subparts apply to fuel gas combustion devices		9/30/05
Heaters and boilers	H2S	Volume-weighted, rolling 3-hour average concentration of H2S in refinery fuel gas	0.10 gr/dscf	12/31/01 until 9/30/05

ConocoPhillips (formerly Tosco Refining Co.) – Ferndale, WA				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Affected facilities under subpart J		Date of lodging

Ergon-West Virginia inc. (formerly Quaker State Oil Refining Corp.) – Newell, WV				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Boiler A	NOx	Install next generation ultra low-NOx burner	EPA to determine emission limit	Install – 12/31/05
Boiler B	NOx	Install next generation ultra low-NOx burner	EPA to determine emission limit	Install – 12/31/08
Boiler C	NOx	Comply with emission limit	0.050 lb/MMBtu (3-hr avg.)	12/31/03
H-101	NOx	Comply with emission limit	0.065 lb/MMBtu (3-hr avg.)	12/31/03
Heaters and boilers	SO2	Affected facilities under subpart J		12/31/06
Heaters and boilers	SO2	Eliminate fuel oil burning except during natural gas curtailment		Date of lodging

Murphy Oil USA Inc. – Superior, WI				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	SO2	Reduce burning of fuel oil	33.3 tons/month (12-month avg.)	5/01/02

Navajo Refining Co. – Lovington, NM				
Unit	Pollutant	Requirement	Emission Limit	Deadline
Heaters and boilers	NOx	Install next generation ultra low NOx burners for all controlled heaters and boilers except Boilers B-7 and B-8		12/31/05 and 12/31/09
Heaters and boilers	SO2	Affected facilities under subpart J		Date of lodging
Heaters and boilers	SO2	Eliminate burning of fuel oil (with a few exceptions)		Date of lodging

Impact of Minor Constituents on the GW of the Mixture as a Function of Concentration

Impact of Minor Constituents on the GWP of the Mixture as a Function of Concentration

GWP Relationship	Concentration of Minor Constituent	GWP of Major Constituent	GWP of Minor Constituent	CO2e of Major Constituent	CO2e of Minor Constituent	Weighted GWP of Combination	Percent by Which GWP of Mixture is Higher than That of Major Constituent
10x (hypothetical)	0.1%	100	1000	99.9	1	100.9	**0.9%**
	0.5%	100	1000	99.5	5	104.5	**4.5%**
	1.0%	100	1000	99	10	109	**9.0%**

Subpart PP

CO_2 Density Value

EPA proposed that standard temperature and pressure for subpart PP be 60 degrees F and 1.000 atm. For the proposal, EPA identified a table in the online database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST) (available at http://webbook.nist.gov/chemistry/fluid/) with density values of CO_2 listed by temperature in degrees F and by pressure in psi. EPA decided to use the density values of CO_2 at 60 degrees F and at 14.713 psi, which is equivalent to 1.00116 atm pressure, as the density value of CO2 in the proposal. That value is 0.0018704 metric tons per standard cubic meter.

Between the proposal and this final rule, EPA identified a second NIST table on the online database with density values of CO2 listed by temperature in degrees F and by pressure in atm. By using this NIST table, we can select a more precise value for the density of CO2 at the exact standard conditions specified for subpart PP. Therefore, in this final action, we are using 0.0018682 metric tons per standard cubic meter as the density of CO_2 because it is the density value of CO2 at 60 degrees F and 1.000 atm.