STATE OF MONTANA AIR QUALITY CONTROL IMPLEMENTATION PLAN	Subject: Yellowstone County Air Pollution Control Program

56.9.4.3 EXHIBIT A - EMISSION LIMITATIONS AND OTHER CONDITIONS - EXXON COMPANY USA, BILLINGS, MONTANA

EXHIBIT A

EMISSION LIMITATIONS AND OTHER CONDITIONS

Exxon Company, USA
Billings, Montana

SECTION 1. AFFECTED FACILITIES

(A) Plant Location:

The Exxon Refinery is located about 3 miles northeast of Billings. The plant is located in Yellowstone County, Township 1 North, Range 26 East, Sections 24 and 25.

(B) Affected Equipment and Facilities:

(1) FCC CO Boiler
(2) F-2 Crude/Vacuum Heater (F-1 Crude Furnace/F-401 Vacuum Heater)
(3) Coker CO Boiler
(4) Minor Fuel Gas Sources: F-3 crude heater, F-3X hydrofiner heater, F-5 hydrofiner heater, F-700 unit, F-201 unit, F-202 unit, F-402 unit, F-551 unit, F-651 unit, and standby boiler house (B-8 boiler).

(C) Nonaffected Equipment and Facilities:

Any equipment or facilities which have no effect on the nature or quantity of emissions of sulfur-bearing gases including, but not limited to, combustion equipment which is fueled exclusively with natural gas or propane.

SECTION 2. DEFINITIONS

(A) The following definitions apply throughout this Stipulation and Exhibit A.

(1) "Annual Emissions" means the amount of SO_2 emitted in a calendar year, expressed in pounds per year rounded to the nearest pound.

Where:

[Annual Emissions] = Σ [Daily Emissions]

(2) "Attachment #1" means the "Performance Specifications for Stack Flow Rate Monitors", attached to this Exhibit and incorporated herein by reference.

(3) "Attachment #2"means the "Analytical Methods for Analyzing the Sour Water Stripper Overheads for Hydrogen Sulfide and Precision and Accuracy Methods for the Sour Water Stripper Flow Meter," attached to this Exhibit and incorporated herein by reference.

(4) "Calendar Day" means a 24-hour period starting at 12:00 midnight and ending at 12:00 midnight, 24 hours later.

(5) "Clock Hour" means one twenty-fourth (1/24) of a Calendar Day and refers to any of the standard 60-minute periods in a day which are generally identified and separated on a clock by the whole numbers one through twelve.

(6) "Continuous Emission Monitoring System (CEMS)" means all equipment necessary to obtain an Hourly SO_2 Emission Rate, provided each SO_2 concentration, stack gas volumetric flow rate, fuel gas flow rate, and sour water flow rate monitor is designed to achieve a temporal sampling resolution of at least one concentration or flow rate measurement per minute and each hydrogen sulfide concentration monitor is designed to achieve a temporal sampling resolution of at least one concentration measurement per three minutes. Such equipment includes:

(a) a continuous emission monitor (CEM) which determines sulfur dioxide concentration in a stack gas, a continuous stack gas volumetric flow rate monitor which determines stack gas flow rate, and associated data acquisition equipment;

(b) a continuous fuel gas monitor which determines hydrogen sulfide (H_2S) concentration in fuel gas, a fuel gas flow rate monitor which determines total refinery fuel gas flow rate, and associated data acquisition equipment; and

(c) a continuous sour water flow rate monitor which determines the sour water flow rate to the T-23 sour water stripper tower and associated data acquisition equipment.

(7) "Daily Average FCC Fresh Feed Rate" means the average of the continuous twenty four (24) Hourly Average FCC Fresh Feed Rates over the course of a Calendar Day.

(8) "Daily Emissions" means the amount of SO_2 emitted in a Calendar Day, expressed in pounds per day rounded to the nearest pound.

Where:

[Daily Emissions] = Σ [Three Hour Emissions]

Each Calendar Day is comprised of eight non-overlapping 3-hour periods. The Three Hour Emissions from all of the 3-hour periods in a Calendar Day shall be used to determine that day's emissions.

(9) "FCC Fresh Feed Rate" means the rate of material fed to the Fluid Catalytic Cracking (FCC) reactor expressed in thousands of barrels of material per day (kBD) and determined using the continuous flow rate meter required by Section 6(B)(6).

(10) "Hourly Average" means an arithmetic average of all Valid and complete 15-minute data blocks in a Clock Hour. Four (4) Valid and complete 15-minute data blocks are required to determine an Hourly Average for each monitor and source per Clock Hour.

Exclusive of the above definition, an Hourly Average may be determined with two (2) Valid and complete 15-minute data blocks, for two of the 24 hours in any Calendar Day.

A complete 15-minute data block for each sulfur dioxide continuous emission monitor, stack gas flow rate monitor, hydrogen sulfide concentration monitor, fuel gas flow rate monitor, and sour water flow rate monitor shall have a minimum of one (1) data point value; however, each monitor shall be operated such that all Valid data points acquired in any 15-minute block shall be used to determine that 15-minute block's reported concentration and flow rate.

(11) "Hourly SO_2 Emission Rate" means the pounds per Clock Hour of sulfur dioxide emissions from a source (stack, fuel gas, or sour water system) determined using Hourly Averages and rounded to the nearest one tenth of a pound.

(a) For stack systems, SO_2 concentrations shall be measured in parts per million (PPM) on either a wet or dry basis.

(i) If the SO_2 concentration is measured on a wet basis, Exxon shall calculate the Hourly SO_2 Emission Rate using the following equation:

$$E_H = K * C_H * Q_H$$

Where:

E_H = Hourly SO_2 Emission Rate in pounds per hour and rounded to the nearest tenth of a pound;

K = 1.663×10^{-7} in (pounds/SCF)/PPM;

C_H = Hourly Average SO_2 concentration in PPM; and

Q_H = stack gas Hourly Average volumetric flow rate, measured on an actual wet basis, converted to Standard Conditions, and reported in standard cubic feet per hour (SCFH).

(ii) If the SO_2 concentration is measured on a dry basis, Exxon shall either install, operate, and maintain a continuous moisture monitor for measuring and recording the moisture content of the stack gases or determine the moisture content of the stack gases continuously (or on an hourly basis) and correct the measured hourly volumetric stack gas flow rates for moisture. Exxon shall calculate the Hourly SO_2 Emission Rate using the following equation:

$$E_H = K * C_H * Q_H * \frac{(100 - \%H_2O)}{100}$$

Where:

E_H = Hourly SO_2 Emission Rate in pounds per hour and rounded to the nearest tenth of a pound;

K = 1.663×10^{-7} in (pounds/SCF)/PPM;

C_H = Hourly Average SO_2 concentration in PPM (dry basis);

Q_H = stack gas Hourly Average volumetric flow rate, measured on an actual wet basis, converted to Standard Conditions, and reported in standard cubic feet per hour (SCFH); and

$\%H_2O$ = Hourly Average stack gas moisture content, in percent by volume.

(b) For refinery fuel gas systems:

(i) H_2S concentrations are measured on an actual wet basis in PPM;

(ii) the fuel gas firing rate for the refinery fuel gas combustion units [listed in Section 1(B)(1), (2), (3) and (4)] shall be measured at the refinery fuel gas header and shall be reported on an actual wet basis in standard cubic feet per hour (SCFH); and:

(iii) the Hourly SO_2 Emission Rate shall be calculated using the following equation:

$$E_H = K * C_H * Q_H$$

Where:

E_H = Hourly SO_2 Emission Rate in pounds per hour and rounded to the nearest tenth of a pound;
K = 1.688×10^{-7} in (pounds/SCF)/PPM;
C_H = Hourly Average fuel gas H_2S concentration in PPM; and
Q_H = actual fuel gas firing rate in SCFH.

(c) For sour water stripper overheads (SWSOH) burning in the F-2 Crude/Vacuum Heater stack or the flare:

(i) the H_2S concentrations in the sour water shall be determined in accordance with Attachment #2 (or another method approved by the Department and EPA) and expressed in milligrams per liter;

(ii) sour water flow rate shall be expressed in gallons per hour; and

(iii) the Hourly SO_2 Emission Rate shall be calculated using the following equation:

$$E_H = K * C_H * Q_H$$

Where:
E_H = Hourly SO_2 Emission Rate from burning of the sour water stripper overheads in the F-1 Crude Furnace or the flare in pounds per hour rounded to the nearest tenth of a pound;
K = 1.57×10^{-5} in [(pounds-liters)/(gallons-milligrams)];

C_H = H_2S concentration of the sour water in milligrams per liter; and

Q_H = sour water flow rate to the T-23 sour water stripper tower in gallons per hour.

(d) For Coker CO Boiler:

Revisions adopted 3/17/00

(i) Coker fresh feed rate shall be expressed in barrels per day (barrels/day); and

(iii) the Hourly SO_2 Emission Rate shall be calculated using the following equation:

$$E_C = 0.0817 * Q_H + 213.02$$

Where:

E_C = Hourly SO_2 Emission Rate from firing Coker Unit flue gases in the Coker CO Boiler in pounds per hour and rounded to the nearest tenth of a pound; and

Q_H = Coker fresh feed rate in barrels/day.

(12) "Operating" means whenever an affected facility is starting up, shutting down, using fuel, or processing materials and SO_2 emissions are expected from the source or stack, except that:

(a) for the FCC CO Boiler stack, start-up and shutting down shall only include time periods when gas-oil feedstock is being delivered to the FCC and

(b) for the purpose of determining the Quarterly Data Recovery Rate for the sour water flow rate CEMS, Operating shall only include those periods when sour water stripper overheads are burned in the flare or in the F-1 Crude Furnace and exhausted up the F-2 Crude/Vacuum Heater stack.

(13) "Quarterly Data Recovery Rate (QDRR)" means the percentage of hours in a calendar quarter when CEMS derived Hourly SO_2 Emission Rate data are available for a source (stack, fuel gas, or sour water system) in comparison to the number of corresponding Operating hours for that source.

If Exxon demonstrates, through the CEMS manufacturer's specifications and stack measurements, that stack conditions during certain periods of startup or shutdown in the FCC CO boiler stack are beyond the design capabilities of the CEMS, then such periods shall not be considered Operating hours for determination of the QDRR.

The (QDRR) for a source shall be calculated in accordance with the following equation:

$$QDRR = \frac{VH}{OH} \times 100\%$$

Where:

VH = Number of hours of Hourly SO_2 Emission Rate data that are also source Operating hours in a calendar quarter;
OH = Total number of source Operating hours in a calendar quarter; and
QDRR = Quarterly Data Recovery Rate.

(14) "Standard Conditions":

(a) means 20.0°C (293.2°K, 527.7°R, or 68.0°F) and 1 atmosphere pressure (29.92" Hg) for stack gas emission calculations using the equation/method in Section 2(A)(11)(a); and

(b) means 15.6°C (288.7°K, 520.0°R, or 60.3°F) and 1 atmosphere pressure (29.92" Hg) for refinery fuel gas emission calculations using the equation/method in Section 2(A)(11)(b).

(15) "Three Hour Average FCC Fresh Feed Rate" means the average of three Hourly Average FCC Fresh Feed Rates in each of the eight non-overlapping three hour periods in a Calendar Day, expressed in thousands of barrels per day.

Where:

$$[\text{Three Hour Average FCC Fresh Feed Rate}] = \frac{\Sigma\,[\text{Hourly Average FCC Fresh Feed Rate}]}{3}$$

Whenever the Hourly Average FCC Fresh Feed Rates are unavailable due to the failure of both the primary and back-up continuous flow rate meters required by Section 6(B)(6), a substituted Hourly Average FCC Fresh Feed Rate shall be used. The substituted Hourly Average FCC Fresh Feed Rate shall be the Hourly Average FCC Fresh Feed Rate determined for the Three Hour Period immediately preceding the Three Hour Period in which the continuous flow rate meter data first became unavailable.

(16) "Three Hour Emissions" means the amount of SO_2 emitted in each of the eight non-overlapping three hour periods in a Calendar Day, expressed in pounds and rounded to the nearest pound.

Where:

[Three Hour Emissions] = Σ [Hourly SO_2 Emission Rates]

Whenever Hourly SO_2 Emission Rates are unavailable and the facility is not Operating, zero pounds per hour shall be substituted for the missing Hourly SO_2 Emission Rates.

(17) "Valid" means data that is obtained from a monitor or meter serving as a component of a CEMS which meets the applicable specifications, operating requirements, and quality assurance and control requirements of Section 6.

SECTION 3. EMISSION LIMITATIONS AND FACILITY MODIFICATIONS

Revisions adopted 3/17/00

Exxon may be subject to (hourly, daily, and annual) SO_2 emission limits in an air quality permit that are more restrictive than those presented here. In those instances where permit emission limits are more stringent, Exxon shall comply with those permit limitations

(A) The following emission limitations shall apply whenever the Yellowstone Energy Limited Partnership facility is receiving Exxon Coker unit flue gas or whenever the Exxon Coker unit is not operating:

(1) Refinery Fuel Gas Combustion from the following units: Coker CO Boiler, FCC CO Boiler, F-2 Crude/Vacuum Heater, F-3 unit, F-3X unit, F-5 unit, F-700 unit, F-201 unit, F-202 unit, F-402 unit, F-551 unit, F-651 unit, and standby boiler house (B-8 boiler);

(a) Combined Three Hour Emissions of SO_2 from the Refinery Fuel Gas Combustion Units shall not exceed 92.4 pounds per three hour period; and

(b) Combined Daily Emissions of SO_2 from the Refinery Fuel Gas Combustion Units shall not exceed 739.2 pounds per Calendar Day.

(2) F-2 Crude/Vacuum Heater Stack:

(a) Three Hour Emissions of SO_2 from the F-2 Crude/Vacuum Heater stack shall not exceed 271.4 pounds per three hour period; and

(b) Daily Emissions of SO_2 from the F-2 Crude/Vacuum Heater stack shall not exceed 2,171.2 pounds per Calendar Day.

(3) FCC CO Boiler Stack:

(a) Three Hour Emissions of SO_2 from the FCC CO Boiler stack shall not exceed those values set forth in the following Table 1a. The three hour SO_2 emission limitations from the FCC CO Boiler stack shall be determined by the Three Hour Average FCC Fresh Feed Rate, expressed in thousands of barrels per day (kBD), rounded up to the nearest whole barrel; and

Table 1a

Three Hour Average FCC Fresh Feed Rate (kBD)	Three Hour SO_2 Emission Limit (lbs of SO_2 per 3-hours)
less than 12.999	5886.8
13.000 to 13.999	6052.0
14.000 to 14.999	6103.7
15.000 to 15.999	6130.6
16.000 to 16.999	6221.8
greater than 17.000	6280.4

(b) Daily Emissions of SO_2 from the FCC CO Boiler stack shall not exceed those values set forth in the following Table 1b. The daily SO_2 emission limitations from the FCC CO Boiler stack shall be determined by the Daily Average FCC Fresh Feed Rate, expressed in thousands of barrels per day (kBD), rounded up to the nearest whole barrel.

Table 1b

Daily Average FCC Fresh Feed Rate (kBD)	Daily SO_2 Emission Limit (lbs of SO_2 per Calendar Day)
less than 12.999	47,094.3
13.000 to 13.999	48,416.3
14.000 to 14.999	48,829.7
15.000 to 15.999	49,044.9
16.000 to 16.999	49,774.5
greater than 17.000	50,243.1

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(B) The following emission limitations shall apply whenever the Yellowstone Energy Limited Partnership facility is not receiving Exxon Coker unit flue gas and the Exxon Coker unit is operating:

(1) Coker CO Boiler stack (includes process exhaust gases and F-202 heater fuel gas firing emissions);

a. Three Hour Emissions of SO_2 from the Coker CO Boiler stack shall not exceed 2,142.9 pounds per 3-hour period; and
b. Daily Emissions of SO_2 from the Coker CO Boiler stack shall not exceed 17,143.1 pounds per Calendar Day."

(2) Refinery Fuel Gas Combustion from the following units: FCC CO Boiler, F-2 Crude/Vacuum Heater, F-3 unit, F-3X unit, F-5 unit, F-700 unit, F-201 unit, F-402 unit, F-551 unit, F-651 unit, and standby boiler house (B-8 boiler);

(a) Combined Three Hour Emissions of SO_2 from the Refinery Fuel Gas Combustion Units shall not exceed 76.2 pounds per three hour period, and

(b) Combined Daily Emissions of SO_2 from the Refinery Fuel Gas Combustion Units shall not exceed 609.6 pounds per Calendar Day.

(3) F-2 Crude/Vacuum Heater Stack:

(a) Three Hour Emissions of SO_2 from the F-2 Crude/Vacuum Heater stack shall not exceed 271.4 pounds per three hour period; and

(b) Daily Emissions of SO_2 from the F-2 Crude/Vacuum Heater stack shall not exceed 2,171.2 pounds per Calendar Day.

(4) FCC CO Boiler Stack:

(a) Three Hour Emissions of SO_2 from the FCC CO Boiler stack shall not exceed those values set forth in the following Table 2a. The three hour SO_2 emission limitations from the FCC CO Boiler stack shall be determined by the Three Hour Average FCC Fresh Feed Rate expressed in thousands of barrels per day (kBD), rounded up to the nearest whole barrel, and

Table 2a

Three Hour Average FCC Fresh Feed Rate (kBD)	Three Hour SO_2 Emission Limit (lbs of SO_2 per 3-hours)
less than 12.999	5231.5
13.000 to 13.999	5485.3
14.000 to 14.999	5743.7
15.000 to 15.999	5966.6
16.000 to 16.999	6190.4
greater than 17.000	6416.4

(b) Daily Emissions of SO_2 from the FCC CO Boiler stack shall not exceed those values set forth in the following Table 2b. The daily SO_2 emission limitations from the FCC CO Boiler stack shall be determined by the Daily Average FCC Fresh Feed Rate expressed in thousands of barrels per day (kBD), rounded up to the nearest whole barrel.

Table 2b

Daily Average FCC Fresh Feed Rate (kBD)	Daily SO_2 Emission Limit (lbs of SO_2 per Calendar Day)
less than 12.999	41,852.1
13.000 to 13.999	43,882.7
14.000 to 14.999	45,949.5
15.000 to 15.999	47,732.5
16.000 to 16.999	49,523.1
greater than 17.000	51,330.8

(C) If continuous flow rate meter data (used to determine the FCC Fresh Feed Rate) is unavailable, the emission limitation shall be determined using a substitute Hourly Average Fresh Feed Rate determined in accordance with the requirements of Section 2(A)(15).

(D) Other Minor Sources;

(1) Exxon shall utilize appropriate maintenance, repair, and operating practices to control emissions of sulfur bearing gases from minor sources such as ducts, stacks, valves, vents, vessels, and flanges which are not otherwise subject to this Stipulation and Exhibit A.

(2) Exxon shall use good engineering judgement and appropriate engineering calculations to quantify emissions from activities that are not otherwise addressed by this Stipulation and Exhibit A but are known to contribute to emissions from sources listed in Section 1(B). In addition, Exxon shall account for such emissions in determining compliance with all applicable emission limits contained in Section 3.

(E) Facility Modifications

(1) By July 1, 1997, Exxon shall modify the FCC CO Boiler stack height to not less than 76.7 meters above ground level. For the purpose of the dispersion model in support of this Stipulation and Exhibit A, the good engineering practice stack height credit for the FCC CO Boiler stack is 76.7 meters.

(2) Exxon shall not restore fuel oil guns to the F-201 unit, F-202 unit, F-402 unit, F-551 unit, F-651 unit, F-700 unit, F-401 unit, F-3X unit, and the Coker CO Boiler. This is consistent with Section 3(B)(2) of Exhibit A of the Stipulation between the Department and Exxon dated April 21, 1995 and adopted by the Board through a Board Order on May 19, 1995 and Section 3 (F)(3) of Exhibit A of the Stipulation

between the Department and Exxon dated July 16, 1996 and adopted by the Board through a Board Order on August 9, 1996.

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(3) Exxon shall not restore the fuel oil guns to the F-2 Crude/Vacuum Heater, F-3 and F-5 units. This is consistent with Section 3(F)(3) of Exhibit A of the Stipulation between the Department and Exxon dated January 28, 1997, and adopted by the Board through Board Order dated February 7, 1997

(4) Beginning January 1, 1998, Exxon shall burn the sour water stripper overheads in the FCC CO Boiler and exhaust those emissions through the FCC CO Boiler stack, except that the sour water stripper overheads may be burned in the F-1 Crude Furnace (and exhausted through the F-2 Crude/Vacuum Heater stack) ~~or in the flare~~ during periods when the FCC CO Boiler is unable to burn the sour water stripper overheads, provided that:

(a) such periods do not exceed 55 days per calendar year and 65 days for any two consecutive calendar years, and
(b) during such periods the sour water stripper system is operating in a two tower configuration.

(5) By January 1, 1998, Exxon shall install an electronic sensor on the valve which supplies sour water stripper overheads to the F-1 Crude Furnace or the flare. The electronic sensor shall be electronically integrated with the Data Acquisition System (DAS) to insure that each time the valve is opened (sour water stripper overheads to the F-1 Crude Furnace or the flare) the DAS automatically records the date and time that the valve is opened and the length of time the SWSOH are directed to the F-1 Crude Furnace or the flare. Whenever the valve is opened, Exxon shall log the date and time and the reasons for such action.

SECTION 4. COMPLIANCE DETERMINATIONS

(A) Compliance with the emission limitations contained in Section 3 (A)(3) and (B)(4) shall be determined using data from the CEMS required by Section 6(B)(1) and (2) and in accordance with the appropriate equation(s) in Section 2(A)(1), (8), (11), and (16) except when CEMS data is not available as provided in Section 2(A)(16). Although the CEMS data is the method of demonstrating compliance on a continuous basis, the data from the testing required by Section 5(A) or Section 6(C and D) shall also be used to demonstrate compliance. Notwithstanding the fact that fuel gas combustion emissions from the FCC CO Boiler are measured by the fuel gas system CEMS and counted against the emission limitations contained in Section 3 (A)(1) and (B)(2), such emissions are also measured by the FCC CO Boiler CEMS and shall be counted against the emission limitations contained in Section 3 (A)(3) and (B)(4).

(B) Compliance with the combined emission limitation for the fuel gas combustion units contained in Section 3(A)(1) and (B)(2) shall be determined by using Hourly Average H_2S concentrations and Hourly Average fuel gas firing rates from the CEMS required by Section 6(B)(3) and (8) and in accordance with the appropriate equation(s) in Section 2(A)(1), (8), (11), and (16) except when CEMS data is not available as provided in Section 2(A)(16).

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(C) Unless a CEMS, or CEMS-Equivalent Alternative Monitoring Plan approved by the Department and EPA, is required for compliance as specified in Section 6(B)(4), compliance with the emission limitations contained in Section 3(B)(1) shall be determined in accordance with the equation in Section 2(A)(11)(d). Whenever Coker Unit flue gases are being burned in the Coker CO Boiler, Exxon shall obtain hourly readings from the Coker unit fresh feed rate meter beginning with the first Clock Hour that Coker unit flue gas is burned in the Coker CO Boiler. Exxon shall record those readings in units of barrels per day (barrels/day) and maintain a log of the hourly readings.

In order to assure the continued reliability of the equation prescribed by Section 2(A)(11)(d) and used to calculate Hourly SO_2 Emission Rates from the Coker CO Boiler, Exxon shall sample the Coker unit reactor feed stream and analyze each of the required samples for sulfur content using ASTM Method 1552-83 or an equivalent method approved by the Department and EPA. The equation prescribed by Section 2(A)(11)(d) shall be considered reliable for predicting SO_2 emissions from the Coker CO Boiler when reactor feed sulfur content is determined to be less than or equal to 5.11 percent by weight. Exxon shall conduct the required sampling in accordance with the following schedule and procedure.

Exxon shall collect one sample of Coker unit reactor feed for each Calendar quarter during any part of which Coker unit flue gases are burned in the Coker CO Boiler. Exxon shall collect the required quarterly sample within four hours of the time the Coker unit flue gas stream is first routed to the Coker CO Boiler during each Calendar quarter. Exxon shall analyze that sample for sulfur content as soon as possible but no later than 5 business days from the time the sample was collected. Exxon is not required to collect a reactor feed sample for any Calendar quarter during which no Coker unit flue gas is burned in the Coker CO Boiler.

If the results of the required sampling and analysis indicate that the sulfur content of the reactor feed is in excess of 5.11 percent by weight, Exxon shall notify the Department of those results by the next business day following its receipt of the results. Exxon shall then work with the Department and, as appropriate, EPA to determine what additional actions, if any, may be necessary to provide assurance that the Coker CO boiler emissions remain within the limitations set forth in Section 3."

(D) If a CEMS or CEMS-Equivalent Alternative Monitoring Plan approved by the Department and EPA is required, compliance shall be determined using data from the:

(1) CEMS and in accordance with the appropriate equation(s) in Section 2(A)(1), (8), (11), and (16) except when CEMS data is not available as provided in Section 2(A)(16); or

(2) CEMS-Equivalent Alternative Monitoring Plan approved by the Department and EPA and in accordance with the equations in Section 2(A)(1), (8), and (16).

(E) Whenever sour water stripper overheads are being burned in the F-1 Crude Furnace (and exhausted through the F-2 Crude/Vacuum Heater stack) ~~or in the flare~~, compliance with the emission limitations contained in Section 3 (A)(2) and (B)(3) shall be determined using flow rate monitoring data from the CEMS required by Section 6(B)(9) and from sampling and analysis of the sour water feed to the T-23 sour water stripper tower. Except for the first two hours after sour water stripper overheads are directed to the F-1 Crude Furnace ~~or the flare~~, Exxon shall collect at least one sample from the sour water feed to the T-23 sour water stripper tower for each of the eight nonoverlapping three hour periods in a Calendar Day. In addition, the time elapsed before collection of the first sample shall not exceed four hours. Exxon shall analyze the sample for H_2S in accordance with the procedures contained in Attachment #2 (or another method approved by the Department and EPA) and Exxon shall use the results to calculate the Hourly SO_2 Emission Rate for each of the hours in the three hour period in accordance with the equations in Section 2 (A) (1), (8), (11), and (16). Notwithstanding the fact that fuel gas combustion emissions from the F-2 Crude/Vacuum Heater are measured by the fuel gas system CEMS and counted against the emission limitations contained in Section 3 (A)(1) and (B)(2), such emission are also counted against the emission limitations contained in Section 3 (A)(2) and (B)(3) if for any reason source testing is conducted on the F-2 Crude/Vacuum Heater stack.

(F) By January 1, 1998, Exxon shall certify for the Department that the facility modifications described in Section 3(E) have been completed and are permanent in nature.

(G) Compliance with the facility modifications contained in Section 3(E) shall be determined by inspection by the Department once a year or whenever as necessary.

(H) Compliance with the Quarterly Data Recovery Rate requirements.

(1) Compliance with the Quarterly Data Recovery Rate requirements contained in Section 6(A)(2) shall be determined in accordance with Section 2(A)(13), with no exceptions for out-of-specification data or monitor downtime, except as provided in Section 6(A)(2).

(2) For quarters in which Operating hours are reduced (short quarters), a determination of whether Exxon has violated the Quarterly Data Recovery Rate (QDRR) requirements in Section 6(A)(2)(b) shall include consideration of whether the reduced Operating hours made compliance with Section 6(A)(2)(b) unreasonable.

(3) Upon determination that the CEMS is not functioning properly, Exxon shall implement short term corrective measures, and if necessary, long term corrective measures to accomplish, as expeditiously as practicable, either:

(a) correction of the failure, or

(b) development, installation (if necessary), testing, maintenance, and operation of a new CEMS or appropriate replacement portions of the affected CEMS.

SECTION 5. EMISSION TESTING

(A) In order to accurately determine the sulfur dioxide emission rates in pounds per hour for the FCC CO boiler stack and the Coker CO boiler stack [if a CEMS or CEMS-Equivalent Alternative Monitoring Plan are required by Section 6(B)(4)], Exxon shall perform annual source testing using EPA-approved methods (40 CFR Part 60, Appendix A, Methods 1-4 and 6/6c as appropriate for this Stipulation and Exhibit A) or an equivalent method approved by the Department and EPA, and in accordance with the Montana Source Testing Protocol (ARM 17.8.106). The annual Relative Accuracy Test Audits (RATAs) required by Sections 6(C and D) may substitute for the annual source tests provided that the flow rate RATA and the concentration RATA are performed simultaneously and additional calculations are made to determine and report the data in pounds per hour of sulfur dioxide.

(B) In order to accurately determine the hydrogen sulfide concentration in parts per million for the fuel gas system, Exxon shall perform annual source testing using EPA-approved methods (40 CFR Part 60, Appendix A, Method 11) or an equivalent method approved by the Department and EPA, and in accordance with the Montana Source Testing Protocol (ARM 17.8.106).

(C) Exxon shall notify the Department in writing of each annual source test a minimum of 25 working days prior to the actual testing (unless otherwise specified by the Department).

SECTION 6. CONTINUOUS MONITORING

(A) CEM Quarterly Data Recovery Rates

(1) "Unusual Circumstances" means circumstances which are unforeseeable, beyond Exxon's control, and which could not reasonably have been prevented or mitigated by Exxon. Such circumstances may include but are not limited to earthquakes, power outages, or fire, but do not include failures of any monitoring or metering equipment or associated data acquisition equipment unless such failures meet the following conditions:

(a) prior to the failure, the equipment was installed, operated, and maintained in accordance with the requirements of Section 6;

(b) upon failure, Exxon initiates the short term corrective measures and the long term corrective measures required by Section 4(H)(3);

(c) within two working days of occurrence, Exxon notifies the Department's Permitting and Compliance Division by telephone of the occurrence of Unusual Circumstances, as defined herein; and

(d) Exxon demonstrates, by utilizing properly signed contemporaneous CEMS operating logs and other relevant evidence, in the first quarterly report following the failure that the failure meets the above conditions.

(2) Quarterly Data Recovery Rates

(a) Notwithstanding the QDRR requirements specified in Section 6(A)(2)(b), whenever a source or stack is Operating, Exxon shall use best efforts to operate the associated CEMS in a manner to achieve the highest Quarterly Data Recovery Rate (QDRR) that is technically feasible,

(b) At a minimum, Exxon shall achieve the following QDRR requirements, unless prevented by Unusual Circumstances or by reduced Operating hours as provided in Section 4(H)(2):

(i) for the FCC CO Boiler stack CEMS, refinery fuel gas system CEMS, and Coker CO Boiler stack CEMS [if required by Section 6(B)(4)(a)], Exxon shall achieve a QDRR for each CEMS of equal to or greater than 90%; and

(ii) for the sour water system CEMS (measures sour water flow rate to the T-23 sour water stripper tower), Exxon shall achieve a QDRR of equal to or greater than 90%.

(c) In its evaluation of whether Exxon used best efforts to achieve the highest QDRR technically feasible, the Department will consider:

(i) the design capabilities of the CEMS, including a demonstration made by Exxon (using manufacturer's specifications and stack measurements) that stack conditions during certain periods of startup or shutdown in the FCC CO Boiler stack are beyond the design capabilities of the CEMS; and whether:

(ii) Exxon has properly operated and maintained the CEMS, including the maintenance of an adequate spare parts inventory;

(iii) Exxon has complied with the quality assurance requirements described in Section 6;

(iv) Exxon has taken timely and appropriate action to correct a failure in the CEMS; and

(v) Unusual Circumstances have occurred, as defined in Section 6(A)(1).

(d) Any time that a CEMS, including the associated data acquisition system, is not functioning properly, Exxon shall implement the short term corrective measures, and if necessary, the long term corrective measures required by Section 4(H)(3).

(B) Affected Sources

(1) By December 1, 1997, Exxon shall install, operate and maintain a continuous emission monitor to measure sulfur dioxide concentrations from the FCC CO Boiler stack.

(2) By December 1, 1997, Exxon shall install, operate and maintain a continuous stack flow rate monitor to measure the stack gas flow rates from the FCC CO Boiler stack.

(3) By December 1, 1997, Exxon shall install, operate and maintain hydrogen sulfide (H_2S) concentration monitoring at the refinery fuel gas header. By August 1, 1998, Exxon shall insure that the hydrogen sulfide (H_2S) concentration monitoring at the refinery fuel gas header is capable of measuring H_2S concentrations in fuel gas in the range of 0-1200 ppmv.

(4) After January 1, 1998, if Exxon exhausts Coker unit flue gas through the Coker CO Boiler stack more than 336 hours in a calendar quarter, Exxon shall within 180 days after the end of the calendar quarter:

(a) install and certify in accordance with 40 CFR Part 60, Appendix B and Method A-1 of Attachment #1 a portable continuous sulfur dioxide concentration monitor and a portable continuous stack flow rate monitor on the Coker CO Boiler stack; or

(b) implement a CEMS-Equivalent Alternative Monitoring Plan which has been approved by the Department and EPA.

(5) After installation and certification of the portable monitors (unless Exxon chooses to implement a CEMS-Equivalent Alternative Monitoring Plan) required by Section 6(B)(4)(a), Exxon may remove the monitors from the Coker CO Boiler stack whenever Coker unit flue gas is not being exhausted through the stack. However, at any time after initial installation and certification of the monitors Exxon exhausts Coker unit flue gas through the Coker CO Boiler stack, Exxon shall within 48 hours:

(a) reinstall the portable monitors at the same location on the Coker CO Boiler stack (including probe position in the stack);

(b) perform a Cylinder Gas Audit (CGA) or Relative Accuracy Audit (RAA) which meets the requirements and specifications of 40 CFR Part 60, Appendix F; and

(c) operate the monitors in accordance with the quality assurance requirements of Section 6 as long as Coker unit flue gas continues to be exhausted through the Coker CO Boiler stack.

(6) Exxon shall operate and maintain a continuous flow rate meter to determine the Fresh Feed Rate to the FCC reactor. In addition, Exxon shall maintain a spare parts inventory (at a minimum, a spare

transducer) that together with the FCC-specific Process Logic Control (PCL) module is capable of functioning as a back-up continuous flow rate meter to measure the Fresh Feed Rate to the FCC reactor. The back-up continuous flow rate meter shall be a completely redundant system capable of obtaining flow rate data in the event of the failure of the primary continuous flow rate meter required by this section. However, the back-up system may rely upon the in-pipe orifice plate and associated mechanical connections that are components of the primary continuous flow rate meter up to, but not including, the transducer.

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(7) Exxon shall operate and maintain a continuous flow rate meter to determine the fresh feed rate to the Coker Unit.

(8) Exxon shall operate and maintain a continuous flow rate monitor on the refinery fuel gas header.

(9) Exxon shall operate and maintain a continuous flow rate monitor to determine the sour water flow rate to the T-23 sour water stripper tower.

(C) CEM Performance Specifications

(1) All continuous SO_2 concentration monitors and hydrogen sulfide concentration monitors required by this control plan shall:

(a) be installed, certified (on a concentration basis), and operated in accordance with the performance specifications in 40 CFR Part 60, Appendix B, Performance Specifications 2 and 7; and

(b) be subject to and meet the quality assurance and quality control requirements (on a concentration basis) of 40 CFR Part 60 Appendix F including but not limited to:

(i) daily calibration drift checks (zero/span or Z/S) using either electro- optical methods or certified calibration gas (however, in addition to the requirements of Appendix F at least one Z/S per calendar week must be conducted using a certified calibration gas),

(ii) quarterly Cylinder Gas Audits (CGA) or Relative Accuracy Audits (RAA), and

(iii) the annual Relative Accuracy Test Audit (RATA).

(2) Exxon shall notify the Department in writing of each annual Relative Accuracy Test Audit a minimum of twenty-five (25) working days prior to the actual testing (unless otherwise specified by the Department).

(D) Stack Gas Flow Rate Monitor Performance Specifications

(1) All continuous stack gas flow rate monitors required by this control plan shall:

(a) be installed, certified (on a flow rate basis), and operated in accordance with Department Method A-1 of Attachment #1; and

(b) be subject to and meet (on a flow rate basis) the quality assurance and quality control requirements of Department Method B-1 of Attachment #1.

(2) Exxon shall notify the Department in writing of each annual Relative Accuracy Test Audit a minimum of twenty-five (25) working days prior to the actual testing (unless otherwise specified by the Department).

(E) Accuracy determinations for refinery fuel gas flow rate monitor and the FCC Fresh Feed Rate Meter shall be required at least once every 48 months or more frequently as routine refinery turn-arounds allow. Accuracy determinations for the sour water flow rate monitor shall be required at least once every 48 months and within three month prior to any scheduled shutdown of the FCC CO Boiler and shall be conducted in accordance with Attachment #2 (or another method approved by the Department and EPA).

SECTION 7. DATA REPORTING REQUIREMENTS

(A) Exxon shall submit quarterly reports on a calendar year basis, beginning with the first calendar quarter of 1998. The quarterly reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to the Department's Permitting and Compliance office in Helena and the Billings Regional Office. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report.

(B) The electronic report format and records structure shall require hourly CEMS data, stack temperature and calibration data to be submitted to the Department as required in Section 7(A). The data shall be submitted to the Department on magnetic or optical media, and such submittal shall follow the reporting format specified by the Department in 1996, as may be subsequently amended. The Department shall reserve the right to call for any necessary future revisions to the reporting format delineated in this Section.

(1) The electronic report shall contain the following:

(a) Hourly Average SO_2 concentrations in PPM from the FCC CO Boiler stack, and Coker CO Boiler stack (if a CEMS is required by Section 6(B)(4) and YELP is not receiving Coker unit flue gas);

(b) Hourly Average stack volumetric flow rates in SCFH from the FCC CO Boiler stack and Coker CO Boiler stack (if a CEMS is required by Section 6(B)(4) and YELP is not receiving Coker unit flue gas);

(c) Hourly Average stack gas temperature in °F from the FCC CO Boiler stack and Coker CO Boiler stack (if a CEMS is required by Section 6(B)(4) and YELP is not receiving Coker unit flue gas);

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(d) Hourly SO_2 Emission Rates in pounds per Clock Hour from the F-2 Crude/Vacuum Heater stack (when sour water stripper overheads are being burned in the F-1 Crude Furnace), FCC CO Boiler stack, refinery fuel gas system, and Coker CO Boiler stack (when YELP is not receiving Coker unit flue gas and the Coker Unit is operating);

(e) Hourly Average H_2S concentrations in PPM from the refinery fuel gas system;

(f) Hourly Average refinery fuel gas combustion units actual fuel gas firing rate (Q_H) as defined in Section 2(A)(11)(b) in SCFH;

(g) daily calibration data from the CEMS required by Section 6(B)(1, 2, 3, and 4);

(h) the Hourly Average FCC Fresh Feed Rate; and

(i) the Hourly Average sour water flow rate to the T-23 sour water stripper tower whenever sour water stripper overheads are being burned in the F-1 Crude Furnace or the flare.

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(j) the Hourly Average fresh feed rate to the Coker Unit.

(2) In addition to submitting the electronic-magnetic quarterly reports to the Department, Exxon shall also record, organize and archive for at least five years the same data, and upon request by the Department, Exxon shall provide the Department with any data archived in accordance with this Section.

(C) The quarterly written report shall consist of summarized CEMS or CEMS-Equivalent Alternative Monitoring Plan data for Daily Emissions, Three Hour Emissions, Quarterly Data Recovery Rates, and text regarding excess emissions. The quarterly written report shall identify each time period when the sour water stripper overheads were burned in the F-1 Crude Furnace (and exhausted through the F-2 Crude/Vacuum Heater stack) or in the refinery flare and the number of sour water stripper towers in service at the time.

(1) The following data shall be recorded, organized, reported, and archived for a minimum of five years:

(a) Three Hour Emission Limitations for SO_2 from the FCC CO boiler stack;

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(b) Three Hour Emissions of SO_2 in pounds per three hour period from the F-2 Crude/Vacuum Heater stack (when sour water stripper overheads are being burned in the F-1 Crude Furnace), FCC CO Boiler stack, Coker CO Boiler stack (when YELP is not receiving Coker unit flue gas and the Coker Unit is operating), and combined Three Hour Emissions from the fuel gas combustion units (listed in Section 3 (A)(1) and

(B)(2), as appropriate);

(c) Daily Emission Limitations for SO_2 from the FCC CO Boiler stack;

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(d) Daily Emissions of SO_2 in pounds per Calendar Day from the F-2 Crude/Vacuum Heater stack (when sour water stripper overheads are being incinerated in the F-1 Crude Furnace), FCC CO Boiler stack, Coker CO Boiler stack (when YELP is not receiving Coker unit flue gas and the Coker Unit is operating), and combined Daily Emissions from the fuel gas combustion units [listed in Section 3 (A)(1) and (B)(2), as appropriate];

(e) the Quarterly Data Recovery Rate for each CEMS required by Section 6(B)(1), (2), (3), (4), (8) and (9) expressed in percent;

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(f) the Operating hours during the calendar quarter for the sources or units associated with the F-2 Crude/Vacuum stack or the flare (when sour water stripper overheads are being burned in the F-1 Crude Furnace or the flare), FCC CO Boiler stack, Coker CO Boiler stack (when YELP is not receiving Coker unit flue gas and the Coker Unit is operating), and refinery fuel gas system;

(g) the dates and times identifying each period of continuous monitoring system downtime during the reporting period, including quality control and quality assurance checks, and the nature of system repairs or adjustments;

(h) the results of the quarterly CGA's or RAA's and flow rate checks, the annual RATAs required in Section 6(C and D), and the annual source tests required by Section 5(A and B);

(i) the results of any quarterly or annual quality assurance tests or checks associated with and required by a CEMS-Equivalent Alternative Monitoring Plan;

(j) any documentation which demonstrates that a CEMS failure meets the conditions of Unusual Circumstances; and

(k) the dates and times that sour water stripper overheads are diverted from the FCC CO Boiler to the F-1 Crude Furnace or the flare, the reasons for the diversions, and corrective actions taken, as appropriate, to avoid future recurrence.

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(l) the results of the sampling of Coker reactor feed and analyses for sulfur content required by Section 4(C).

(2) For each Calendar Day on which any emission limitations are exceeded, the written report shall identify the source or unit with excess emissions and include the following information in a report submittal as specified in Section 7(A):

(a) total hours of operation with excess emissions, the Hourly SO_2 Emission Rates, and Three Hour

Emissions;

(b) all information regarding reasons for operating with excess emissions; and

(c) corrective actions taken to mitigate excess emissions.

(D) Upon request from a representative of the Department, EPA or Yellowstone County Air Pollution Control, Exxon shall provide Hourly SO_2 Emissions Rate data for any prior day not covered by the latest quarterly report for the sources or units covered by this control plan and listed in Section 1(B).

(E) By January 1, 2000, the Department shall reevaluate the reporting requirements of this Section and determine if revisions are necessary or desirable. The purpose of the reevaluation is to determine if the reporting requirements should be modified to more closely meet the informational needs of the Department and the public, and to reduce or simplify the requirements for Exxon while still providing the necessary information. Any revisions shall be made only after consultation with Exxon, consideration of the number and type of data requests made by the public, and the Department's emission inventory and compliance needs.

SECTION 8. ADDITIONAL REQUIREMENTS AND CONDITIONS

Except as otherwise provided herein, nothing in this Stipulation, Exhibit A, or Attachments shall be construed to alter Exxon's obligations under any other applicable state, federal and local laws and regulations, orders, and permit conditions. In any enforcement proceeding pertaining to such other requirements, Exxon reserves the right to raise any and all available equitable or legal defenses.

SECTION 9. GENERAL CONDITIONS

(A) Inspection - For purposes of ensuring compliance with this Exhibit A and Attachments, Exxon shall, pursuant to 75-2-403, MCA, allow the Department representative(s) access to all SO_2 emitting sources at the Exxon facility such that, the Department representative(s) may, pursuant to 75-2-403, MCA, enter and inspect, at any reasonable time, any property, premises, or place, except a private residence, on or at which an SO_2 emitting source is located or is being constructed or installed. The Department representatives shall be allowed to conduct surveys, collect samples, obtain emissions data, audit any monitoring equipment (CEMS), or observe any monitoring or testing, and conduct all other necessary functions related to this control plan.

As provided in Section 75-2-105, MCA, Exxon may seek a court order declaring certain trade secret information as confidential and not a matter of public record. If Exxon claims that certain information is entitled to trade secret protection, the Department shall maintain such information as confidential pending issuance of a court order under Section 75-2-105, MCA, provided that Exxon initiate such court action within

14 days of delivering the information to the Department.

(B) Enforcement - Any violation of a limitation, condition or other requirement contained herein ("Stipulation Requirement") constitutes grounds for judicial or administrative enforcement action. If the incident causing the violation would also form the basis of a violation of ARM Title 17, Chapter 8, or of Title 75, Chapter 2, MCA, the Department shall not count the violation of the Stipulation Requirement as an additional or separate violation incident for penalty calculation and assessment purposes.

ATTACHMENT 1
PERFORMANCE SPECIFICATIONS FOR STACK FLOW RATE MONITORS
(Includes Methods A-1 and B-1)

METHOD A-1
INSTALLATION AND INITIAL CERTIFICATION
IN-STACK OR IN-DUCT FLOW MONITORS

1.0 FLOW MONITOR INSTALLATION AND MEASUREMENT LOCATION

Install the flow monitor in a location that provides representative volumetric flow for all operating conditions. Such a location provides an average velocity of the flue gas flow over the stack or duct cross section, provides a representative SO_2 emission rate (in lb/hr), and is representative of the pollutant concentration monitor location. Where the moisture content of the flue gas affects volumetric flow measurements, use the procedures in both Reference Methods 1 and 4 of 40 CFR Part 60, Appendix A to establish a proper location for the flow monitor.

The Department recommends (but does not require) performing a flow profile study following the procedures in 40 CFR Part 60, Appendix A, Test Method 1, Section 2.5 to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points required to obtain a representative flow value. The procedure in 40 CFR part 60, Appendix A, Test Method 1, Section 2.5 may be used even if the flow measurement location is greater than or equal to 2 equivalent stack or duct diameters downstream or greater than or equal to 1/2 duct diameter upstream from a flow disturbance. If a flow profile study shows that cyclonic (or swirling) or stratified flow conditions exist at the potential flow monitor location that are likely to prevent the monitor from meeting the performance specifications of this Method, then the Department recommends either (1) selecting another location where there is no cyclonic (or swirling) or stratified flow condition, or (2) eliminating the cyclonic (or swirling) or stratified flow condition by straightening the flow, e.g., by installing straightening vanes. The Department also recommends selecting flow monitor locations to minimize the effects of condensation, coating, erosion, or other conditions that could adversely affect flow monitor performance.

1.1 Acceptability of Flow Monitor Location

The installation of a flow monitor is acceptable if (1) the location satisfies the minimum siting criteria of Method 1 in Appendix A to 40 CFR Part 60 (i.e., the location is greater than or equal to eight stack or duct diameters downstream and two diameters upstream from a flow disturbance; or, if necessary, two stack or duct diameters downstream and one-half stack or duct diameter upstream from, a flow disturbance), (2) the results of a flow profile study, if performed, are acceptable (i.e., there are no cyclonic (or swirling) or stratified flow conditions), and (3) the flow monitor satisfies the performance specifications of this Method. If the flow monitor is installed in a location that does not satisfy these physical criteria, but the monitor achieves the performance specifications of this Method, then the Department and EPA may certify the location as acceptable.

1.2 Alternative Flow Monitoring Location

Whenever the flow monitor is installed in a location that is greater than or equal to two stack or duct diameters downstream and greater or equal to one-half diameter upstream from a flow disturbance, and/or in a location that is acceptable based on a flow profile study, but nevertheless the monitor does not achieve the performance specifications of this Method, perform another flow profile study (the procedures described in 40 CFR Part 60, Appendix A, Method 1, Section 2.5 may be used) to select an alternative flow monitoring installation site.

Whenever the owner or operator successfully demonstrates that modifications to the exhaust duct or stack (such as installation of straightening vanes, modifications of ductwork, and the like) are necessary for the flow monitor to meet the performance specifications, the Department and EPA may approve an interim alternative flow monitoring methodology and an extension to the required certification date for the flow monitor.

Where no location exists that satisfies the physical siting criteria in section 1.1, where the results of flow profile studies performed at two or more alternative flow monitor locations are unacceptable, or where installation of a flow monitor in either the stack or the ducts is demonstrated to be technically infeasible, the owner or operator may petition the Department and EPA for an alternative method for monitoring flow.

2.0 FLOW MONITOR EQUIPMENT SPECIFICATIONS

2.1 Instrument Span - General Requirements

In implementing Section 2.1.1 of this Method, to the extent practicable, measure at a range such that the majority of readings obtained during normal operation are between 25 and 75 percent of full-scale range of the instrument.

2.1.1 Instrument Span for Flow Monitors

Select the full-scale range of the flow monitor so that it is consistent with Section 2.1 of this Method, and can accurately measure all potential volumetric flow rates at the flow monitor installation site. Establish the span value of the flow monitor at a level which is approximately 80% of the full-scale range and 125% of the maximum expected flow rate. Based upon the span value, establish reference values for the calibration error test in accordance with Section 2.2.1.

If the volumetric flow rate exceeds the flow monitor's ability to accurately measure and record values, adjust the full-scale range, span value, and reference values as described above and in Section 2.2.1. Record the new span value and report the new span value and reference values as parts of the results of the calibration error test required by Method B-1. Whenever the span value is adjusted, use reference values for the calibration error test based on the new span value.

2.2 Flow Monitor Design for Quality Control Testing

Design all flow monitors to meet the applicable performance specifications of this Method.

2.2.1 Flow Monitor Calibration Error Test

Design and equip each flow monitor to allow for a daily calibration error test consisting of at least two reference values: (1) Zero to 20 percent of span or an equivalent reference value (e.g., pressure pulse or electronic signal) and (2) 50 to 70 percent of span. Flow monitor response, both before and after any adjustment, must be capable of being recorded by the data acquisition and handling system. Design each flow monitor to allow a daily calibration error test of (1) the entire flow monitoring system, from and including the probe tip (or equivalent) through and including the data acquisition and handling system, or (2) the flow monitoring system from and including the transducer through and including the data acquisition and handling system.

2.2.2 Flow Monitor Interference Check

Design and equip each flow monitor in a manner to minimize interference due to moisture. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on a least a daily basis to prevent velocity sensing interference, and (2) a means for detecting leaks in the system on a least a quarterly basis (manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (e.g., backpurging system) to prevent velocity sensing interference.

3.0 FLOW MONITOR PERFORMANCE SPECIFICATIONS

3.1 Flow Monitor Calibration Error

The calibration error of flow monitors shall not exceed 3.0 percent based upon the span of the instrument as calculated using Equation A-1 of this Method.

3.2 Flow Monitor Relative Accuracy

Except as provided in this Section, the relative accuracy for flow monitors, where volumetric gas flow is measured in scfh, shall not exceed 20.0 percent. For affected units where the average of the flow monitor measurements of gas velocity during the relative accuracy test audit is less than or equal to 10.0 fps, the mean value of the flow monitor velocity measurements shall not exceed ±2.0 fps of the reference method mean value in fps wherever the relative accuracy specification above is not achieved.

4.0 DATA ACQUISITION AND HANDLING SYSTEMS

Automated data acquisition and handling systems shall: (1) read and record the full range of pollutant concentrations and volumetric flow from zero through span; and (2) provide a continuous record of all measurements and required information in an electronic format specified by the Department and capable of transmission via an IBM-compatible personal computer diskette or other electronic media. These systems also shall have the capability of interpreting and converting the individual output signals from a pollutant concentration monitor and a flow monitor to produce a continuous readout of pollutant mass emission rates in pounds per hour.

Data acquisition and handling systems shall also compute and record monitor calibration error .

5.0 INITIAL FLOW MONITOR CERTIFICATION TESTS AND PROCEDURES

5.1 Flow Monitor Pretest Preparation

Install the components of the continuous flow monitor as specified in Sections 1.0, 2.0, and 3.0 of this Method, and prepare each system component and the combined system for operation in accordance with the manufacturer's written instruction. Operate the unit(s) during each period when measurements are made.

5.2 7-Day Calibration Error Test for Flow Monitors

Measure the calibration error of each flow monitor according to the following procedures.

Introduce the reference signal corresponding to the values specified in Section 2.2.1 of this Method to the probe tip (or equivalent), or to the transducer. During the 7-day certification test period, conduct the calibration error test once each day while the unit is operating (as close to 24-hour intervals as practicable). Record the flow monitor responses by means of the data acquisition and handling system. Calculate the calibration error using Equation A-1 of this Method.

Do not perform any corrective maintenance, repair, replacement or manual adjustment to the flow monitor during the 7-day certification test period other than that required in the monitor operation and maintenance manual. If the flow monitor operates within the calibration error performance specification, (i.e., less than or equal to 3 percent error each day and requiring no corrective maintenance, repair, replacement or manual adjustment during the 7-day test period) the flow monitor passes the calibration error test portion of the certification test. Whenever automatic adjustments are made, record the magnitude of the adjustments. Record all maintenance and required adjustments. Record output readings from the data acquisition and handling system before and after all adjustments.

5.3 Flow Monitor Relative Accuracy

Within 90 days of installation concurrent relative accuracy test audits may be performed by conducting simultaneous SO_2 concentration and volumetric flow relative accuracy test audit runs, or by alternating an SO_2 relative accuracy test audit run with a flow relative accuracy test audit run until all relative accuracy test audit runs are completed. Where two or more probes are in the same proximity, care should be taken to prevent probes from interfering with each other's sampling. For each SO_2 pollutant concentration monitor and each flow monitor, calculate the relative accuracy with data from the relative accuracy test audits.

Perform relative accuracy test audits for each flow monitor at normal operating load expressed in terms of percent of flow monitor span. If a flow monitor fails the relative accuracy test, the relative accuracy test audit must be repeated.

Complete each relative accuracy test audit within a 7-day period while the unit is operating in a normal condition. Do not perform corrective maintenance, repairs, replacements or adjustments during the relative accuracy test audit other than as required in the operation and maintenance manual.

5.3.1 Calculations

Using the data from the relative accuracy test audits, calculate relative accuracy in accordance with the procedure and equations specified in Section 6 of this Method.

5.3.2 Reference Method Measurement Location

Select a location for reference method measurements that is (1) accessible; (2) in the same proximity as the monitor or monitoring system location; and (3) meets the requirements of Method 1 (or 1A) of 40 CFR Part

60, Appendix A for volumetric flow, except as otherwise indicated in this Section.

5.3.3 Reference Method Traverse Point Selection

Select traverse points that (1) ensure acquisition of representative samples of pollutant concentration, moisture content, temperature, and flue gas flow rate over the flue cross section; and (2) meet the requirements of Method 1 (or 1A) (for volumetric flow), and Method 4 (for moisture determination) in 40 CFR part 60, Appendix A.

5.3.4 Sampling Strategy

Conduct the reference method tests so they will yield results representative of the moisture content, temperature, and flue gas flow rate from the unit and can be correlated with the flow monitor measurements. Conduct any moisture measurements that may be needed simultaneously with the flue gas flow rate measurements. To properly correlate volumetric flow rate data with the reference method data, mark the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s).

5.3.5 Correlation of Reference Method and Continuous Emission Monitoring System

Confirm that the monitor or monitoring system and reference method test results are on consistent moisture, pressure, and temperature basis (e.g., since the flow monitor measures flow rate on a wet basis, Method 2 test results must also be on a wet basis). Compare flow-monitor and reference method results on a scfh basis. Also consider the response time of the flow monitoring system to ensure comparison of simultaneous measurements. For each relative accuracy test audit run, compare the measurements obtained from the flow monitor against the corresponding reference method values. Tabulate the paired data in a table similar to the one shown in Figure 1.

5.3.6 Number of Reference Method Tests

Perform a minimum of nine sets of paired monitor (or monitoring system) and reference method test data for every required relative accuracy test audit. Conduct each set within a period of 30 to 60 minutes.

The tester may choose to perform more than nine sets of reference method tests. If this option is chosen, the tester may reject a maximum of three sets of the test results as long as the total number of test results used to determine the relative accuracy is greater than or equal to nine. Report all data, including the rejected data, and reference method test results.

5.3.7 Reference Methods

The following methods from 40 CFR Part 60, Appendix A or their approved alternatives are the reference methods for performing relative accuracy test audits: Method 1 or 1A for siting; Method 2 (or 2A, 2C, or 2D as appropriate) for velocity; and Method 4 for moisture.

6.0 CALCULATIONS

6.1 Flow Monitor Calibration Error (Drift)

For each reference value, calculate the percentage calibration error based upon span using the following equation:

$$CE = \frac{(R-A)}{S} x\ 100 \qquad \text{(EQ.A-1)}$$

Where:

CE = Calibration error;

R = Low or high level reference value specified in Section 2.2.1 of this Method;
A = Actual flow monitor response to the reference value; and
S = Flow monitor span.

Whenever the flow rate exceeds the monitor's ability to measure and record values accurately, adjust the span to prevent future exceedances. If process parameters change or other changes are made such that the expected flue gas velocity may change significantly, adjust the span to assure the continued accuracy of the monitoring system.

6.2 Relative Accuracy for Flow Monitors

Analyze the relative accuracy test audit data from the reference method tests for flow monitors using the following procedures. Summarize the results on a data sheet. An example is shown in Figure 1. Calculate the mean of the monitor or monitoring system measurement values. Calculate the mean of the reference method values. Using data from the automated data acquisition and handling system, calculate the arithmetic differences between the reference method and monitor measurement data sets. Then calculate the arithmetic mean of the difference, the standard deviation, the confidence coefficient, and the monitor or monitoring system relative accuracy using the following procedures and equations.

6.2.1 Arithmetic Mean

Calculate the arithmetic mean of the differences, $\bar{d}$, of a data set as follows.

(Eq. A-2) $$\bar{d} = \frac{1}{n} \sum_{i=1}^{n} d_i$$

Where:

n=Number of data points

$\sum_{i=1}^{n} d_i$ = Algebraic sum of the individual differences d_i

d_i = The difference between a reference method value and the corresponding continuous flowrate monitoring system value (RM_i-FR_i) at a given point in time i.

When calculating the arithmetic mean of the difference of a flow monitor data set, be sure to correct the monitor measurements for moisture if applicable.

6.2.2 Standard Deviation

Calculate the standard deviation, S_d of a data set as follows:

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - [\frac{(\sum_{i=1}^{n} d_i)^2}{n}]}{n-1}} \qquad \text{(Eq. A-3)}$$

6.2.3 Confidence Coefficient

Calculate the confidence coefficient (one-tailed), cc, of a data set as follows.

$$CC = t_{0.025} \frac{S_d}{\sqrt{n}} \quad \text{(Eq. A-4)}$$

where:

$t_{0.025}$ = *t value (see Table* 2)

TABLE 2 T-VALUES

n-1	$t_{0.025}$	n-1	$t_{0.025}$	n-1	$t_{0.025}$
1.......	12.706	12	2.179	23	2.069
2.......	4.303	13	2.160	24	2.064
3.......	3.182	14	2.145	25	2.060
4.......	2.776	15	2.131	26	2.056
5.......	2.571	16	2.120	27	2.052
6.......	2.447	17	2.110	28	2.048
7.......	2.365	18	2.101	29	2.045
8.......	2.306	19	2.093	30	2.042
9.......	2.262	20	2.086	40	2.021
10......	2.228	21	2.080	60	2.000
11......	2.201	22	2.074	>60	1.960

6.2.4 Relative Accuracy

Calculate the relative accuracy of a data set using the following equation.

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} x\ 100 \qquad \text{(Eq. A-5)}$$

where:

RM = Arithmetic means of the reference method values.

$|\bar{d}|$ = The absolute value of the mean difference between the reference method values and the corresponding continuous flow monitor values.

$|cc|$ = The absolute value of the confidence coefficient.

FIGURE 1.-RELATIVE ACCURACY DETERMINATION (FLOW MONITORS)

Run No.	Date & Time	Flow rate (Normal) (scf/hr)*		
		RM	M	Diff
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
Mean or mean of differences				
Confidence coefficient				
Relative accuracy				

* Make sure RM and M are on a consistent moisture basis.

METHOD B-1
ON-GOING QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES
FOR IN-STACK AND IN-DUCT FLOW MONITORS

1.0 FREQUENCY OF FLOW MONITOR TESTING

A summary chart showing each quality assurance test and the frequency at which each test is required is located at the end of this Method in Table 1.

1.1 **Daily** Flow Monitor Assessments

For each flow monitor perform the following assessments during each day in which the unit is operating. These requirements are effective as of the date when the monitor or continuous emission monitoring system completes certification testing.

1.1.1 Calibration Error Test for Flow Monitors

Test, compute, and record the calibration error of each flow monitor at least once on each operating day. Introduce the reference values (specified in section 2.2.1 of Method A-1) to the probe tip (or equivalent) or to the transducer. Record flow monitor output from the data acquisition and handling system before and after any adjustments to the flow monitor. Keep a record of all maintenance and adjustments. Calculate the calibration error using Equation A-1 in Method A-1.

1.1.2 Flow Monitor Interference Check

Perform the daily flow monitor interference checks specified in section 2.2.2 of Method A-1 at least once per operating day (when the unit(s) operate for any part of the day).

1.1.3 Flow Monitor Recalibration

Adjusts the calibration, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification for the flow monitor in Method A-1. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective.

1.1.4 Flow Monitor Out-of-Control Period

An out-of-control period occurs when either the low or high level reference value calibration error exceeds 6.0 percent based upon the span value for five consecutive daily periods or 12.0 percent for any daily period. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out of control if two or more complete and valid readings are obtained during that hour. An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of completion of the failed interference check and ends with the hour of completion of an interference check that is passed. During any period that the flow monitor is out-of-control, the data may not be used in calculating emission compliance nor be counted towards meeting minimum data recovery requirements.

1.1.5 Flow Monitor Data Recording

Record and tabulate all calibration error test data according to month, day, clockhour, and magnitude in scfh. Program monitors that automatically adjust data to the corrected calibration values (e.g., microprocessor control) to record either: (1) The unadjusted flow rate measured in the calibration error test prior to resetting the calibration or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

1.2 **Quarterly** Flow Monitor Assessments

For each flow monitor, conduct a quarterly stack velocity and flow rate check by performing a velocity traverse and visual inspection of the pitot tubes. Perform the following assessments during each calendar quarter in which the unit operates. This requirement is effective as of the calendar quarter following the calendar quarter in which the flow monitor is provisional certified.

1.2.1 Flow Monitor Leak Check

For differential pressure flow monitors, perform a leak check of all sample lines (a manual check is acceptable) at least once during each unit operating quarter. Conduct the leak checks no less than two months apart.

1.2.2 Flow Monitor Flow Rate Check

Once during each operating quarter and for each flow monitor, perform a flow rate check by completing a single velocity traverse, calculating the associated average flow rate, and comparing the average flow with the concurrent flow measured by the continuous flow monitor. The flow rate check shall be performed at normal operating rates or load level. The flow rate check shall be performed in accordance with Section 5.3 of Method A-1 as appropriate for a single traverse. The difference (PD) between the average flow rate determined by the single velocity traverse and the continuous flow monitor shall not exceed 20 percent as determined by equation B-1. If the single velocity traverse fails to meet the 20% difference specification, the owner/operator may conduct an additional single velocity traverse or a complete Relative Accuracy Test Audit (RATA) in accordance with Section 5.3 of Method A-1 in order to demonstrate compliance with the 20% difference or 20% relative accuracy requirements.

$$PD = \frac{TF - FR}{TF} \times 100 \qquad \text{(Eq. B-1)}$$

Where:

PD = Percent Difference;

TF = Traverse Flow (scfh);
FR = Continuous Flow Monitor Flow (scfh); and
TF and FR are on a consistent moisture basis.

If the Relative Accuracy of the latest annual Relative Accuracy Test Audit (RATA) conducted pursuant to Section 1.3.1 is less than 10%, the single velocity traverse flow rate check may be discontinued. However, if future RATAs indicate a Relative Accuracy of 10% or greater, performance of the single velocity traverse flow rate check shall resume.

1.2.3 Flow Monitor Out-of-Control Period

An out-of-control period occurs when a flow monitor fails the quarterly flow rate check (the difference between the average flow rate determined by the velocity traverse and the continuous flow monitor exceeds 20%), the visual inspection of the pitot tube indicates pluggage or wear, or if a sample line leak is detected. The out-of-control period begins with the hour of the failed flow rate check, visual inspection, or leak check and ends with the hour of a satisfactory flow rate check, RATA, leak check, or cleaning or replacement of the pitot tube. During any period that the flow monitor is out-of-control, the data may not be used in calculating emission compliance nor be counted towards meeting minimum data recovery requirements.

1.3 **Annual** Flow Monitor Assessments

For each flow monitor, perform the following assessments once annually. This requirement is effective as of the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified.

1.3.1 Flow Monitor Relative Accuracy Test Audit

For flow monitors, relative accuracy test audits shall be performed annually. The relative accuracy audit shall be performed at the normal operating rate or load level (with a minimum of 9 paired velocity traverses).

The relative accuracy test audit shall be conducted according to the procedures and specifications of Method A-1.

1.3.2 Flow Monitor Out-of-Control Period

An out-of-control period occurs under any of the following conditions: (1) the relative accuracy of a flow monitor exceeds 20.0 percent or (2) for low flow situations (≤10.0 fps), the flow monitor mean value (if applicable) exceeds ±2.0 fps of the reference method mean whenever the relative accuracy is greater than 20.0 percent. For flow relative accuracy test audits, the out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit. During any period that the flow monitor is out-of-control, the data may not be used in calculating emission compliance nor be counted towards meeting minimum data recovery requirements.

TABLE 1.-FLOW MONITOR QUALITY ASSURANCE TEST REQUIREMENTS

Test	QA test frequency requirements		
	Daily	Quarterly	Annual
Calibration Error (2 pt.)	x		
Interference (flow)	x		
Visual probe check		x	
Flow rate check (single traverse)		x[1]	
Leak (flow)		x[2]	
RATA (flow)			x

[1] The owner/operator has an option to perform a RATA if the quarterly

flow rate check (single traverse) fails specifications. In addition, if the Relative Accuracy determined by the latest RATA is less than 10%, the quarterly single velocity traverse flow rate check may be discontinued. However, if future RATAs indicate a Relative Accuracy of 10% or greater, performance of the quarterly single velocity traverse flow rate check shall resume.

[2] The leak check requirement only applies to differential pressure flow rate monitors and does not apply to thermal or ultrasonic flow rate monitors.

ATTACHMENT # 2

ANALYTICAL METHODS FOR ANALYZING THE SOUR WATER STRIPPER OVERHEADS FOR HYDROGEN SULFIDE AND PRECISION AND ACCURACY METHODS FOR THE SOUR WATER STRIPPER FLOW METER

METHOD #6A-1

ANALYTICAL METHOD FOR ANALYZING THE SOUR WATER STRIPPER FEED FOR HYDROGEN SULFIDE (H_2S)

(October 1999)

1.0 SCOPE AND APPLICATION

This method is applicable to the measurement of total and dissolved sulfides in sour water produced by the refinery. Acid insoluble sulfides are not measured by the use of this test. (Copper sulfide is the only common sulfide in this class).

2.0 SUMMARY OF METHOD

Excess iodine is added to a sample which has been treated with zinc acetate to produce zinc sulfide. The iodine oxidizes the sulfide to sulfur under acidic conditions. The excess iodine is back titrated with sodium thiosulfate.

3.0 COMMENTS

Reduced sulfur compounds, such as sulfite, thiosulfate and hydrosulfite, which decompose in acid may yield erratic results. Also, volatile iodine-consuming substances such as mercaptans will give high results.

The sample source is hot and under pressure.

The volumes of preservative and the normality of the reagents have been modified from the referenced methods. The modifications are to make the method appropriate for the expected high concentrations of sulfide in the samples. The method calculations are also modified to correct for the sample dilution from the preservative.

4.0 APPARATUS

4.1 Ordinary laboratory glassware.

4.2 130 ml HDPE bottles. These bottles are pre-charged with preservative. For the sour water stripper feed inlet the bottle contains 5 ml of zinc acetate and 10 ml of sodium hydroxide.

5.0 REAGENTS

5.1 Hydrochloric acid, HCl, 6 N

5.2 Standard iodine solution, 0.1000 N: Dissolved 20 to 25 g KI in a little water in a liter volumetric and add 12.8 g iodine. Allow to dissolve. Dilute to 1 liter and standardize against 0.1000 N sodium thiosulfate using a starch indicator.

5.3 Sodium thiosulfate 0.1000N: Dissolve 24.82 g $Na_2S_2O_3 \bullet 5H_2O$ in water. Add 1 ml of chloroform and dilute to 1000 ml.

5.4 Starch indicator: Dissolved 10 g soluble starch and 10 mg Hg_2I in hot water and dilute to 4 liters.

5.5 Standardize the sodium thiosulfate against KIO_3. Adjust the concentration to 0.1000 N. Use this sodium thiosulfate to standardize the iodine solution.

5.6 Zinc acetate solution, 2N: Dissolve 220 g $Zn(C_2H_3O_2)_2 \bullet 2H_2O$ in water and dilute to one liter.

5.7 Sodium hydroxide, 6N: Dissolve 240 grams of sodium hydroxide in 800 ml of water, Dilute to one liter. Caution: much heat will be liberated.

6.0 SAMPLING

6.1 The sample bottles (4.2) are pre-charged with zinc acetate and sodium hydroxide preservative and labeled. The sample bottle sample contains 5 ml of preservative and 10 of sodium hydroxide.

6.2 The sample is obtained by carefully filling the appropriate bottle. Fill the bottle slowly to prevent the sample from splashing the preservative out or overflowing the bottle. The bottle should be completely filled with no headspace air. If necessary, the sides of the bottle can be squeezed while screwing on the lid to exclude the remaining air.

6.3 Experience shows that the pH of these samples, taken and preserved as described, are above 9. No further pH adjustment is required.

7.0 PROCEDURE

7.1 Shake the container to suspend all solids and remove the sample. Measure the volume of sample. This is used to correct the results for the dilution due to the preservative. Check the pH of the sample using pH test paper to confirm that it is 9 or higher.

7.2 Place 20 ml of standard iodine solution (5.2) into a 500 ml iodine titration flask.

7.3 Add 15 ml of 6N HCl (5.1).

7.4 Thoroughly mix the sample and quickly take a 25 ml aliquot and place it in the flask.

7.5 If the iodine color disappears, add more iodine until the color remains. Record the total number of milliliters of standard iodine used steps 7.2 and 7.5.

7.6 Titrate with the reducing solution (0.1 N sodium thiosulfate) to a pale straw color. Add the starch indicator and titrate until the blue color disappears. Record the volume used.

8.0 CALCULATIONS

8.1 Sulfide as H_2S, mg/l = $\frac{(A - B) \times 17.01 \times 1000}{\text{sample aliquot, ml} \times K}$

Where: A = Volume of Iodine, ml * Normality of Iodine

B = Volume of Thiosulfate, ml * Normality of Thiosulfate

K = $\frac{\text{ml of sample - ml of preservative}}{\text{ml of sample}}$

This is a correction for the preservative volume. The volume of sample is the total volume in the sample container including the preservative. The volume of preservative is the volume added to the container before the sample was obtained.

9.0 REFERENCES

9.1 Standard Methods for the Examination of Water and Wastewater, 19^{th} Edition, p 4-127, Method 4500-S_2 F, (1995)

EPA Method 376.1

METHOD #6B
PRECISION AND ACCURACY METHOD FOR THE SOUR WATER STRIPPER FLOW METER TO T-23

1.0 SCOPE AND APPLICATION

This method is applicable to any typical orifice type flow meter that is installed consistent with ASME code procedures found under ASME MFC-3M-1989 (Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi). Such a designed and installed flow meter will, if maintained consistent with these procedures, have an accuracy of 2 percent of the upper range.

2.0 SUMMARY OF METHOD

The calibration is to ensure installation parameters are maintained and the flow measurement components maintain their integrity during the period of operation so that the output can be relied upon as representative of a 2 percent accurate flow.

3.0 PROCEDURE FOR ANNUAL CALIBRATION

3.1 Meter Information

Obtain the sour water feed meter installation information for the meter to the second tower of the Sour Water Strippers. This information should be verified as consistent with the designed system and as installed in the field.

3.2 Field Verification

Verify the field orifice meter actually installed is that which was installed originally by checking the orifice plate tab at the meter between the orifice flanges. Verify the transmitter differential pressure range is the same as required in the design and originally set.

3.3 Transmitter Span Check and Zero Check

3.3.1 Span Check

Block transmitter at the three valve manifold. As a precaution during this procedure, the technicians should position themselves upwind due to the potential of elevated H_2S concentrations in this stream. Connect the multimeter to the transmitter and observe and note the transmitter output. Unblock the high pressure side manifold valve, vent the low pressure side of the transmitter making sure the vent is pointing away from the technician. The transmitter output should go up scale to 20 + milliamps direct current (madc).

3.3.2 Tap/Lead Line Plugging Check

Close low pressure vent. Open low pressure manifold valve and block in high pressure manifold valve making sure the vent is pointed away from the technician. The transmitter output should go down scale to less than 4.0 madc. Open equalizer valves on manifold. This will allow blowing of the low side lead line to check for any plugging or plugged tap. If it blows satisfactorily, close the low pressure side transmitter vent and manifold equalizing valve. Next open the transmitter high pressure side vent and then the high pressure manifold valve to allow blowing the high pressure lead line to check for any plugging or plugged tap.

3.3.3 Zero Check

Close transmitter high pressure side vent, leave high pressure manifold valve open and open manifold equalizer valve. The transmitter output should go to zero. If no adjustment is required, proceed to place the instrument back into service. If outside a 2% accuracy, follow the steps in Section 4.0 of these procedures for additional accuracy checks.

4.0 FORTY-EIGHT MONTH ACCURACY CHECK

4.1 Scope and Application

This part of the procedure will be conducted at least three months prior to a FCC/CO Boiler turnaround but not more than a 48 months interval, to ensure the accuracy of this meter prior to a know period when the sour water stripper overheads will be incinerated in the Crude Furnace for an extended period of up to 40 days.

4.2 Meter Information and Field Verification

Follow steps 3.1 and 3.2 to ensure the meter installation has the designed components in place.

4.3 Transmitter Zero and Span Check

Block the transmitter at the root valves and at the three valve manifold. As a precaution during this procedure, the technicians should position themselves upwind due to the potential of elevated H_2S concentrations in this stream. Bleed pressure with the bleeder pointed away from the technician. Remove wiring and tubing, inspect flex and tubing and replace as needed. Remove mounting and equalizer bolts and remove transmitter. Take transmitter to the Refinery Instrument Shop for Bench Check calibration.

Remove body flanges and clean all parts and check for corrosion and other problems that could affect transmitter performance. Repair or replace as needed to ensure an accurate flow measurement. Apply proper pressure to define and calibrate at zero and full scale for the span. Adjust as necessary and check repeatability.

4.4 Field Inspection of Meter Installation

After the meter transmitter is removed, remove the orifice plate and measure its diameter to confirm no change has occurred. Establish if a new plate is required due to corrosion or erosion and obtain for installation. In either case, a new meter factor must be developed consistent with ASME MFC-3M-1989 or equivalent (Exxon has incorporated these requirements into a rigorous computer design tool used for this purpose).

Once the orifice plate is removed, visually inspect the process piping. Clean as needed and measure the inside pipe diameter of the up stream and downstream piping to confirm no deterioration has occurred. If more than a 2% increase in orifice or pipe diameter has occurred, a new meter factor must be developed consistent with ASME MFC-3M-1989 or equivalent (Exxon has incorporated these requirements into a rigorous computer design tool used for this purpose).

4.5 Field Zero and Span Check to Confirm Proper Installation

Reinstall all parts using new bolts and gaskets. Open root valves, bypass on the equalizer and the low side tap of the equalizer. Close the bleeder. This will give a zero reading. Verify zero reading on the transmitter. When zero checking is complete, check the range utilizing a handheld digital pneumatic meter by pumping up pressure to match the design and installed maximum pressure reading. Verify the maximum span on the transmitter. If there is more than a 2% difference, make necessary adjustments. If within the 2% accuracy, proceed to put the instrument back in service. If transmitter will not operate properly while conducting the zero and span checks, remove from service and take to the Refinery Instrument Shop to conduct another full Bench Check on the transmitter. If unable to achieve a 2% accuracy, repair or replace and follow the above steps on the repaired or replaced instrument until a 2% accuracy is obtained on the field installed instrument. Proceed to recommission as appropriate and in a timely manner check to be sure operations is satisfactory.

5.0 TRACK CHANGES

If any changes to the original equipment, i.e. orifice plate, piping changes, differential pressure or meter factor, place new data into the refinery meter tracking information system and use for future meter calibrations and accuracy checks.