This proposed rule also does not have tribal implications because it will not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified by Executive Order 13175 (65 FR 67249, November 9, 2000). This action also does not have Federalism implications because it does not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999). This action merely proposes to approve a state rule implementing a Federal standard, and does not alter the relationship or the distribution of power and responsibilities established in the Clean Air Act. This proposed rule also is not subject to Executive Order 13045 ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), because it is not economically significant.

In reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the Clean Air Act. In this context, in the absence of a prior existing requirement for the State to use voluntary consensus standards (VCS), EPA has no authority to disapprove a SIP submission for failure to use VCS. It would thus be inconsistent with applicable law for EPA, when it reviews a SIP submission, to use VCS in place of a SIP submission that otherwise satisfies the provisions of the Clean Air Act. Thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) do not apply. This proposed rule does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Particulate matter, Reporting and recordkeeping requirements.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: June 30, 2006.

Alexis Strauss,

Acting Regional Administrator, Region IX.

[FR Doc. 06–6111 Filed 7–11–06; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–R08–OAR–2006–0098; FRL–8191–7]

40 CFR Part 52

RIN 2008–AA00

Federal Implementation Plan for the Billings/Laurel, Montana, Sulfur Dioxide Area

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) proposes to promulgate a Federal Implementation Plan (FIP) containing emission limits and compliance determining methods for several sources located in Billings and Laurel, Montana. EPA is proposing a FIP because of our previous partial and limited disapprovals of the Billings/Laurel Sulfur Dioxide (SO_2) SIP. The intended effect of this action is to assure attainment of the SO_2 national ambient air quality standard (NAAQS) in the Billings/Laurel, Montana area. EPA is taking this action under sections 110 and 307 of the Clean Air Act (Act).

DATES: *Comments:* Comments on the proposal must be received on or before September 11, 2006.

Public Hearing: If requested by July 26, 2006, EPA will hold a public hearing on August 10, 2006. If a public hearing is requested, EPA will hold the public hearing at the following time and location: 9 a.m. to 2 p.m. at the Lewis and Clark Room, MSU—Billings, 1500 University Drive, Billings, Montana. The purpose of such a hearing would be for EPA to receive comments and ask clarifying questions. The hearing would not be an opportunity for questioning of EPA officials or employees. Call the individual listed in the **FOR FURTHER INFORMATION CONTACT** if you would like to request a hearing, schedule time to speak at the hearing, or confirm whether a hearing will occur. If a hearing is held, speakers will be limited to 10 minutes. It would be helpful, but it is not required, if speakers bring a written copy of their comments to leave with us.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R08–OAR–2006–0098, by one of the following methods:

- *Http://www.regulations.gov*. Follow the on-line instructions for submitting comments.
- *E-mail: long.richard@epa.gov* and *ostrand.laurie@epa.gov*.
- *Fax:* (303) 312–6064 (please alert the individual listed in the **FOR FURTHER INFORMATION CONTACT** if you are faxing comments).
- *Mail:* Richard R. Long, Director, Air and Radiation Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 999 18th Street, Suite 200, Denver, Colorado 80202–2466.
- *Hand Delivery:* Richard R. Long, Director, Air and Radiation Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 999 18th Street, Suite 300, Denver, Colorado 80202–2466. Such deliveries are only accepted Monday through Friday, 8 a.m. to 4:55 p.m., excluding Federal holidays. Special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–R08–OAR–2006–0098. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an ''anonymous access'' systems, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA, without going through *http://www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm*. For additional instructions on submitting comments, go to Section I. General Information of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: All documents in the docket are listed in the *http://*

www.regulations.gov index. Although listed in the index, some information is not publicly available, *e.g.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air and Radiation Program, Environmental Protection Agency (EPA), Region 8, 999 18th Street, Suite 300, Denver, Colorado 80202–2466. EPA requests that if at all possible, you contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 8 a.m. to 4 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Laurie Ostrand, Air and Radiation Program, Mailcode 8P–AR, Environmental Protection Agency (EPA), Region 8, 999 18th Street, Suite 200, Denver, Colorado 80202–2466, (303) 312–6437, *ostrand.laurie@epa.gov*.

SUPPLEMENTARY INFORMATION:

Table of Contents

Definitions

For the purpose of this document, we are giving meaning to certain words or initials as follows:

(i) The words or initials *Act* or *CAA* mean or refer to the Clean Air Act, unless the context indicates otherwise.

(ii) The initials *CEMS* mean or refer to continuous emission monitoring system.

(iii) The initials *CO* mean or refer to carbon monoxide.

(iv) The words *EPA, we, us* or *our* mean or refer to the United States Environmental Protection Agency.

(v) The initials *FIP* mean or refer to Federal Implementation Plan.

(vi) The initials H_2S mean or refer to hydrogen sulfide.

(vii) The initials *MBER* mean or refer to the Montana Board of Environmental Review.

(viii) The initials *MDEQ* mean or refer to the Montana Department of Environmental Quality.

(ix) The initials *MSCC* mean or refer to the Montana Sulphur & Chemical Company.

(x) The initials *NAAQS* mean or refer to National Ambient Air Quality Standards.

(xi) The initials *SIP* mean or refer to State Implementation Plan.

(xii) The initials SO_2 mean or refer to sulfur dioxide.

(xiii) The words *state* or *Montana* mean the State of Montana, unless the context indicates otherwise.

(xiv) The initials *SRU* mean or refer to sulfur recovery unit.

(xv) The initials *SWS* mean or refer to sour water stripper.

I. General Information

A. What Should I Consider as I Prepare My Comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through *http://www.regulations.gov* or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for Preparing Your Comments.* When submitting comments, remember to:

a. Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).

b. Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

c. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

d. Describe any assumptions and provide any technical information and/or data that you used.

e. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

f. Provide specific examples to illustrate your concerns, and suggest alternatives.

g. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

h. Make sure to submit your comments by the comment period deadline identified.

II. Background

A. General Background

Billings and Laurel are situated in the Yellowstone River Valley in south-central Montana. The Yellowstone River Valley runs from southwest to northeast and is the dominant topographical feature influencing airflow over the area. Windroses [1] for the area reflect the valley orientation. Southwest winds are the most common, followed by northeast winds.

The terrain in the vicinity of Billings and Laurel is upland bench which is steeply cut by the Yellowstone River and its tributaries. The bench lies at an elevation of 4000 feet while the valley in Billings is approximately 3000 feet above sea level (asl) and in Laurel is approximately 3300 feet asl. A constriction in the Yellowstone Valley occurs between central Billings and the Lockwood area located to the east. The valley is generally 3 or 4 miles wide but narrows to a little over a mile wide at the constriction. Nearby terrain, such as the Sacrifice Cliff to the southeast of Billings and the Rimrocks to the north, rises abruptly and is often higher than the tallest smoke stack. Laurel is located within the Yellowstone Valley approximately 15 miles southwest of Billings. The valley near Laurel is 3 or 4 miles wide. Nearby terrain to the northwest and southeast of Laurel rises abruptly and is often higher than the tallest smoke stack.

The major sulfur dioxide (SO_2) emitting industries in the Billings area are the ConocoPhillips [2] and

[1] A windrose is a diagram showing the relative frequency or frequency and strength of winds from different directions (Websters 9th New Collegiate Dictionary).

[2] When the state originally adopted the Billings/Laurel SO_2 SIP, the ConocoPhillips Refinery was

ExxonMobil[3] Petroleum Refineries, Western Sugar Company, the PPL Montana, LLC J.E. Corette Power Plant,[4] Montana Sulphur & Chemical Company (MSCC) (gas processing plant, sulfur recovery and sulfur products), and Yellowstone Energy Limited Partnership (YELP) (cogeneration power plant). The major SO_2 emitting industry in the Laurel area is the CHS Inc. Petroleum Refinery.[5] Although Laurel and Billings are 15 miles apart, the industries in Billings have some impact on the air quality in Laurel and the industry in Laurel has some impact on the air quality in Billings.

On March 3, 1978 (43 FR 8962), the Laurel area was designated as nonattainment for the primary SO_2 national ambient air quality standard (NAAQS). *See* also 40 CFR 81.327. The nonattainment area consists of an area with a two-kilometer radius around CHS Inc. This designation was based on measured and modeled violations of the NAAQS. EPA reaffirmed this nonattainment designation on September 11, 1978 (43 FR 40412). The 1990 Clean Air Act Amendments, enacted November 15, 1990, again reaffirmed the nonattainment designation of Laurel with respect to the primary SO_2 NAAQS. Since the Laurel nonattainment area had a fully approved part D plan, the state was not required to submit a revised plan for the area under the 1990 Amendments (*see* sections 191 and 192 of the Act).

On March 3, 1978 (43 FR 8962), those areas in the state that had not been identified as not meeting the SO_2 NAAQS were designated as ''Better Than National Standards.'' The Billings area was in that portion of the state that was designated as ''Better Than National Standards.''

The Act requires EPA to establish NAAQS which protect public health and welfare. NAAQS have been established for SO_2. The Act also requires states to prepare and gain EPA approval of a plan, termed a State Implementation Plan (SIP), to assure that the NAAQS are attained and maintained. Dispersion modeling completed in 1991 and 1993 for the Billings/Laurel area of Montana predicted that the SO_2 NAAQS were not being attained.[6] As a result, EPA (pursuant to sections 110(a)(2)(H) and 110(k)(5) of the Act) requested the State of Montana to revise its previously approved SIP for the Billings/Laurel area. In response, the State submitted revisions to the SIP on September 6, 1995, August 27, 1996, April 2, 1997, July 29, 1998, and May 4, 2000.

B. SIP Background

1. SIP Call

We issued a request that the State of Montana revise the Billings/Laurel area SO_2 SIP by letter to the Governor of Montana, dated March 4, 1993 (*see* reference document Z). The request letter reflected our preliminary finding regarding the SIP's substantial inadequacy, and was published in the **Federal Register** on August 4, 1993 (58 FR 41430) (*see* reference document Y). We sometimes refer to such a request as a SIP Call. In the request letter, we declared that the SIP Call would become final agency action when we made a binding determination regarding the State of Montana's response to the SIP Call. We made such a binding determination regarding the SIP Call when we partially and limitedly approved and partially and limitedly disapproved the Billings/Laurel SO_2 SIP revisions submitted by the State of Montana in response to the request letter.[7] *See* 67 FR 22168, 22173 (May 2, 2002) (*see* reference document AA).

2. SIPs Submitted in Response to SIP Call

Our 1993 SIP Call called for the State of Montana to submit a SIP revision for the Billings/Laurel area by September 4, 1994. On September 6, 1995, the Governor of Montana submitted a SIP revision in response to the SIP Call. The SIP was later amended with revisions submitted on August 27, 1996, April 2, 1997, July 29, 1998, and May 4, 2000. Copies of the complete SIP revisions are contained in the docket for our action on the SIP. (*See* docket #R8–99–01.)

3. EPA's Actions on State's Billings/Laurel SO_2 SIP

(a) EPA's May 2, 2002, final action.

On May 2, 2002 (67 FR 22168)[8] (see reference document AA), we partially approved, partially disapproved, limitedly approved and limitedly disapproved provisions of the Billings/Laurel SO_2 SIP.[9] Specifically:

(i) We disapproved the following provisions of the Billings/Laurel SO_2 SIP:[10]

- The escape clause (paragraph 22 in the ExxonMobil and MSCC 1998 stipulations, and paragraph 20 in the CHS Inc., ConocoPhillips, Corette Power Plant, Western Sugar, and YELP 1998 stipulations.)
- The MSCC stack height credit and emission limits on the sulfur recovery unit (SRU) 100-meter stack (paragraph 1 of the ExxonMobil 1998 stipulation, paragraphs 1 and 2 of the MSCC 1998 stipulation, and sections 3(A)(1)(a) and

known as the Conoco Refinery. Throughout this document we will refer to the refinery as ConocoPhillips.

[3] When the state originally adopted the Billings/Laurel SO_2 SIP, the ExxonMobil Refinery was known as the Exxon Refinery. Throughout this document we will refer to the refinery as ExxonMobil.

[4] When the state originally adopted the Billings/Laurel SO_2 SIP, the PPL Montana, LLC J.E. Corette Power Plant was known as the Montana Power Company, J.E. Corrette Plant. Throughout this document we will refer to the power plant as the Corette Power Plant.

[5] When the state originally adopted the Billings/Laurel SO_2 SIP, CHS Inc. Petroleum Refinery was known as the Cenex Petroleum Refinery. Throughout this document we will refer to the refinery as CHS Inc.

[6] See the study for the Billings Gasification, Inc. (BGI) (now YELP) permit in 1991 and the GeoResearch, Inc. (GRI) study commissioned by the Billings City Council in 1993 (document #'s II.G–13 and II.G–12, respectively, in Docket #R8–99–01).

[7] In some cases, a SIP rule may contain certain provisions that meet the applicable requirements of the Act, but that are *inseparable* from other provisions that do not meet all the requirements. Although the submittal may not meet all of the applicable requirements, we may consider whether the rule, as a whole, has a strengthening effect on the SIP. If this is the case, limited approval may be used to approve a rule that strengthens the existing SIP as representing an improvement over what is currently in the SIP and as meeting some of the applicable requirements of the Act. At the same time we would disapprove the rule for not meeting all of the applicable requirements of the Act. Under a limited approval/disapproval action, we simultaneously approve and disapprove the entire rule even though parts of the rule satisfy, and parts do not satisfy, requirements under the Act. The disapproval only concerns the failure of the rule to meet a specific requirement of the Act and does not affect incorporation of the rule as part of the approved, federally enforceable SIP. We use this mechanism when the rule, despite its flaws, will strengthen the federally enforceable SIP.

In other cases, a SIP rule may contain certain provisions that meet applicable requirements of the Act, but that are *separable* from other provisions that do not meet applicable requirements. Where a separable portion of the submittal meets applicable requirements, partial approval may be used to approve that part of the submittal and partial disapproval to disapprove the provisions that do not meet applicable requirements of the Act.

EPA's interpretation of the Act regarding approving and disapproving SIPs is discussed further in a July 9, 1992, memorandum title ''Processing of State Implementation Plan (SIP) Submittals,'' from John Calcagni to Regional Air Division Directors. (See reference document A.)

[8] See also June 7, 2002 corrections notice (67 FR 39473) (reference document KKK).

[9] See footnote #7.

[10] The SIP was submitted in the form of orders, stipulations, exhibits and attachments for each source covered by the plan. The majority of the requirements are contained in the exhibits. Throughout this document when we refer to an exhibit, we mean exhibit A to the stipulation for the specified source. For purposes of our May 2, 2002, SIP action the stipulations and exhibits to which we refer were adopted by the Montana Board of Environmental Review (MBER) on June 12, 1998. MBER adopted revised stipulations and exhibits for some sources on March 17, 2000. To distinguish between the two sets of stipulations and exhibits, we refer to either the 1998 stipulation or exhibit for a particular source, or the 2000 stipulation or exhibit.

(b) and 3(A)(3) of the MSCC 1998 exhibit).

- The emission limit on MSCC's auxiliary vent stacks, section 3(A)(4) of MSCC's 1998 exhibit.
- The attainment demonstration, because of improper stack height credit and emission limits at MSCC.
- The attainment demonstration for lack of flare emission limits at CHS Inc., ConocoPhillips, ExxonMobil, and MSCC.
- The attainment demonstration, because of the disapproval of the emission limit for MSCC's auxiliary vent stacks.
- The Reasonably Available Control Measures (RACM) (including Reasonably Available Control Technology (RACT)) and Reasonable Further Progress (RFP) requirements for CHS Inc.
- The provisions that allow sour water stripper overheads to be burned in the flare at CHS Inc. and ExxonMobil (*i.e.*, the following phrase from section 3(B)(2) of CHS Inc.'s 1998 exhibit and section 3(E)(4) of ExxonMobil's 1998 exhibit: ''or in the flare''; the following phrases in section 4(D) of CHS Inc.'s 1998 exhibit and section 4(E) of ExxonMobil's 1998 exhibit: ''or in the flare'' and ''or the flare''.)

(ii) We limitedly approved and limitedly disapproved the following provision:

- The emission limit for the 30-meter stack at MSCC (section 3(A)(2) of MSCC's 1998 exhibit) because it lacked a reliable compliance monitoring method.

(iii) We did not act on the following provisions:

- The provisions in section 6(B)(3) of MSCC's 1998 exhibit that require certain monitoring equipment to support the variable emission limit.[11]
- YELP's emission limits (in sections 3(A)(1) through (3) of YELP's 1998 exhibit).
- ExxonMobil's coker CO-boiler emission limitation (in section 3(B)(1) of ExxonMobil's 1998 exhibit).
- ExxonMobil's F–2 crude/vacuum heater stack emission limits and attendant compliance monitoring methods (sections 3(A)(2), 3(B)(3), 4(E) and method #6A of attachment #2 of ExxonMobil's 1998 exhibit; and the following phrase from section 3(E)(4) of ExxonMobil's 1998 exhibit ''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.'')
- ExxonMobil's fuel gas combustion emission limits and attendant compliance monitoring methods (in sections 3(A)(1), 3(B)(2), 4(B), and 6(B)(3) of ExxonMobil's 1998 exhibit).
- CHS Inc.'s combustion sources emission limitations and attendant compliance monitoring methods (sections 3(A)(1)(d), 4(B), 4(D) and method #6A of attachment #2 of CHS Inc.'s 1998 exhibit; and the following phrase from section 3(B)(2) of CHS Inc.'s 1998 exhibit ''except that those sour water stripper overheads may be burned in the main crude heater (and exhausted through the main crude heater stack) or in the flare during periods when the FCC CO boiler is unable to burn the sour water stripper overheads from the ''old'' SWS, provided that such periods do not exceed 55 days per calendar year and 65 days for any two consecutive calendar years.'')

(iv) In a separate action published on May 2, 2002 (67 FR 22242)[12] *(see reference document BB), we proposed action on some provisions of the Billings/Laurel SO_2 SIP submitted on July 29, 1998, and May 4, 2000.*[13] We later finalized action on these provisions on May 22, 2003 (68 FR 27908) (*see* discussion below and reference document CC).

(v) We approved the following provisions:

- All provisions of the SIP that were not partially disapproved, limitedly disapproved, omitted from our action, or addressed in our May 2, 2002, proposal.

(b) EPA's May 22, 2003, final action.

On May 22, 2003 (68 FR 27908)[14] (see reference document CC), we partially approved, limitedly approved, and limitedly disapproved provisions of the Billings/Laurel SO_2 SIP. Specifically:

(i) We approved the following provisions:

- YELP's emission limits in sections 3(A)(1) through (3) and reporting requirements in section 7(C)(1)(b) of YELP's 2000 exhibit.
- Provisions related to the burning of SWS overheads in the F–1 Crude Furnace (and exhausted through the F–2 Crude/Vacuum Heater stack) at ExxonMobil in sections 3(E)(4) and 4(E) (excluding ''or in the flare'' and ''or the flare'' in both sections), 3(A)(2), and 3(B)(3) of ExxonMobil's 1998 exhibit, and method #6A–1 of attachment #2 of ExxonMobil's 2000 exhibit.
- Minor changes in sections 3, 3(A), and 3(B) (only the introductory paragraphs); and sections 3(E)(3), 6(B)(7), 7(B)(1)(d), 7(B)(1)(j), 7(C)(1)(b), 7(C)(1)(d), 7(C)(1)(f), and 7(C)(1)(l) of ExxonMobil's 2000 exhibit.

(ii) We limitedly approved and limitedly disapproved the following provisions:

- Provisions related to the fuel gas combustion emission limits at ExxonMobil in sections 3(B)(2), 4(B), and 6(B)(3) of ExxonMobil's 1998 exhibit, and section 3(A)(1) of ExxonMobil's 2000 exhibit.
- Provisions related to ExxonMobil's coker CO-boiler emission limit in sections 2(A)(11)(d), 3(B)(1), and 4(C) of ExxonMobil's 2000 exhibit.
- Provisions related to the burning of SWS overheads at CHS Inc. in sections 3(B)(2) and 4(D) (excluding ''or in the flare'' and ''or the flare'' in both sections), 3(A)(1)(d), and 4(B) of CHS Inc.'s 1998 exhibit, and method #6A–1 of attachment #2 of CHS Inc.'s 2000 exhibit.

4. Appeal of EPA's Action on Billings/Laurel SO_2 SIP

On June 10, 2002, MSCC petitioned the United States Court of Appeals for the Ninth Circuit for review of EPA's May 2, 2002, final SIP action. Subsequently, MSCC and EPA agreed to a stay of the litigation pending EPA's final action on this FIP. The case is captioned *Montana Sulphur & Chemical Company* v. *United States Environmental Protection Agency,* No. 02–71657. No petitions for judicial review were filed regarding EPA's May 22, 2003, SIP action.

[11] Since we disapproved MSCC's variable emission limit, we did not believe it made sense to approve section 6(B)(3) of MSCC's 1998 exhibit, which requires MSCC to install certain monitoring equipment to support the use of the variable limit. Section 6(B)(3) would be needed only if we approved MSCC's variable emission limit.

[12] See also June 14, 2002 correction notice (67 FR 40897) (reference document LLL).

[13] On July 28, 1999 (64 FR 40791), we proposed to conditionally approve certain provisions of the SIP based on the Governor's commitment to address concerns we had raised. The Governor submitted a SIP revision on May 4, 2000, which was intended to fulfill the commitments. Since the Governor submitted a SIP revision to fulfill the commentments, we did not finalize our proposed conditional approval and instead proposed separate action on parts of the July 29, 1998, submittal (*i.e.,* those parts we proposed to conditionally approve on July 28, 1999) and all of the May 4, 2000, submission (which in some cases modified the provisions of the July 29, 1998, submittal).

[14] See also June 2, 2003 correction notice (68 FR 32799) (reference document MMM).

C. FIP Background

Under section 110(c) of the Act, whenever we disapprove a SIP in whole or in part we are required to promulgate a FIP. Specifically, section 110(c) provides:

''(1) The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—

(A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under [section 110(k)(1)(A)] [15], or

(B) disapproves a State implementation plan submission in whole or in part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.''

Thus, because we disapproved portions of the Billings/Laurel SO_2 SIP, and the attainment demonstration, we are required to promulgate a FIP.

Section 302(y) defines the term ''Federal implementation plan'' in pertinent part, as:

''[A] plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions or emissions allowances) * * *''

More simply, a FIP is ''a set of enforceable federal regulations that stand in the place of deficient portions of a SIP.'' *McCarthy* v. *Thomas,* 27 F.3d 1363, 1365 (9th Cir. 1994). As the Court of Appeals for the D.C. Circuit noted in a 1995 case, FIPs are powerful tools to remedy deficient state action:

''The FIP provides an additional incentive for state compliance because it rescinds state authority to make the many sensitive technical and political choices that a pollution control regime demands. The FIP provision also ensures that progress toward NAAQS attainment will proceed notwithstanding inadequate action at the state level.''

Natural Resources Defense Council, Inc. v. *Browner,* 57 F.3d 1122, 1124 (D.C. Cir. 1995).

When EPA promulgates a FIP, courts have not required EPA to demonstrate explicit authority for specific measures: ''We are inclined to construe Congress' broad grant of power to the EPA as including all enforcement devices reasonably necessary to the achievement and maintenance of the goals established by the legislation.'' *South Terminal Corp.* v. *EPA, 504* F.2d 646, 669 (1st Cir. 1974). As the Ninth Circuit stated in a case involving a FIP with far-reaching consequences in Los Angeles: ''The authority to regulate pollution carries with it the power to do so in a manner reasonably calculated to reach that end.'' *City of Santa Rosa* v. *EPA,* 534 F.2d 150, 155 (9th Cir. 1976), *vacated and remanded on other grounds sub nom. Pacific Legal Foundation* v. *EPA, 429 U.S. 990 (1976).*

In addition to giving EPA remedial authority, section 110(c) enables EPA to assume the powers that the state would have to protect air quality, when the state fails to adequately discharge its planning responsibility. As the Ninth Circuit held, when EPA acts to fill in the gaps in an inadequate state plan under section 110(c), EPA '' 'stands in the shoes of the defaulting State, and all of the rights and duties that would otherwise fall to the State accrue instead to EPA.' '' *Central Arizona Water Conservation District* v. *EPA*, 990 F.2d 1531, 1541 (9th Cir. 1993). As the First Circuit held in an early case:

''[T]he Administrator must promulgate promptly regulations setting forth 'an implementation plan for a State' should the state itself fail to propose a satisfactory one * * *. The statutory scheme would be unworkable were it read as giving to EPA, when promulgating an implementation plan for a state, less than those necessary measures allowed by Congress to a state to accomplish federal clean air goals. We do not adopt any such crippling interpretation.''

South Terminal Corp. v. *EPA, supra,* at 668 (citing previous version of section 110(c)).

III. FIP Proposal

As discussed above, in this proposed rulemaking, EPA is fulfilling its mandatory duty under section 110(c) of the Act to propose FIP provisions for the Billings/Laurel, Montana area because of our limited and partial disapproval of portions of the Billings/Laurel SO_2 SIP submitted by Montana. Our proposed FIP would not replace the SIP entirely, but instead would only replace elements of the SIP or fill gaps in the SIP as necessary to ensure attainment and maintenance of the SO_2 NAAQS. In cases where the provisions of the FIP would address emissions activities differently or establish different requirements than provisions of the SIP, the provisions of the FIP would take precedence.

Our proposed FIP only impacts four stationary sources: CHS Inc., ConocoPhillips, ExxonMobil and Montana Sulphur & Chemical Company (MSCC). We caution that if any of these sources are subject to more stringent requirements under other provisions of the Act (*e.g.*, section 111 or 112, part C, or SIP-approved permit programs under Part A), our proposal of any FIP requirement would not excuse any of these sources from meeting other more stringent requirements. Also, our proposed FIP is not meant to imply any sort of applicability determination under other provisions of the Act (*e.g.*, section 111 or 112, part C, or SIP-approved permit programs under Part A).

A. Flare Requirements Applicable to All Sources

We disapproved the Billings/Laurel SO_2 SIP as it applied to the attainment demonstration because the SIP lacked enforceable emission limits for flares, while the SIP submission took credit for such emission limits. *See* our May 2, 2002, final rulemaking action at 67 FR 22168. Because of this disapproval we are proposing emission limits and compliance determining methods for flares at CHS Inc., ConocoPhillips (including Jupiter Sulfur),[16] ExxonMobil, and MSCC. The flare emission limits and compliance determining methods are being proposed for the purpose of assuring attainment and maintenance of the SO_2 NAAQS.

Since the state's attainment demonstration assumed that the main flares at each source were limited to 150 pounds of SO_2 per three hour period, and that the Jupiter Sulfur SRU flare would share an emission limit of 75 pounds of SO_2 per three hour period with the Jupiter Sulfur SRU/ATS stack, we are proposing to promulgate flare emission limits that reflect the state's assumption that emissions from these points would not exceed these levels. More specific detail regarding each of the sources' emission limits is provided below in sections III. B, C, D, and E.

While we are proposing that 150 pounds of SO_2 per three hour period be the limit for the main flares, we are soliciting input on whether we should instead limit the main flares to 500 pounds of SO_2 per calendar day. This value is consistent with a trigger point for certain analyses contained in settlements between the United States and CHS Inc., ConocoPhillips, and ExxonMobil. For purposes of our attainment demonstration, we have assumed that the 500 pounds would be emitted from the four main flares over a three-hour period rather than a

[15] Section 110(k)(1)(A) requires the Administrator to promulgate minimum criteria that any plan submission must meet before EPA is required to act on the submission. These completeness criteria are set forth at 40 CFR 51, Appendix V.

[16] The ConocoPhillips Billings Refinery also includes the Jupiter Sulfur Recovery Facility (*see* reference document S).

calendar day. Our evaluation shows that even under these conditions, the 3-hour SO_2 NAAQS would be attained.

Note that if we adopted the 500 pound value for this FIP, we would impose it as an enforceable emission limit, not just a trigger point for further analyses.

We are proposing that the flare limits will apply at all times without exception. We recognize that flares are sometimes used as emergency devices at refineries and that it may be difficult to comply with these flare limits during malfunctions. However, under our interpretations of the Clean Air Act, it is not appropriate to create automatic exemptions from SIP limits needed to demonstrate attainment. (See reference document RRR, September 20, 1999 memorandum titled ''State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown,'' from Steven A. Herman and Robert Perciasepe, to Regional Administrators (referred to hereafter as ''1999 policy statement'').) We do interpret the CAA to allow owners and operators of sources to assert an affirmative defense to penalties in appropriate circumstances, but normally we would not view such an affirmative defense as appropriate in areas where a single source or small group of sources has the potential to cause an exceedance of the NAAQS. See 1999 policy statement. We solicit comment on whether it would be appropriate to include in our final FIP the ability to assert an affirmative defense to penalties only (not injunctive relief) for violations of the flare limits. If we were to establish such a provision, we anticipate it would closely follow the guidance contained in our 1999 policy statement.

We are also proposing that compliance with the emission limits be determined by measurement of the total sulfur concentration and volumetric flow rate of the gas stream to the flare(s), followed by calculation, using appropriate equations, of SO_2 emitted per 3-hour period. The assumption is that when the gas stream is combusted in a flare, all of the sulfur in the gas stream converts to SO_2 and is emitted to the atmosphere. Also, by knowing the volumetric flow rate of the gas stream to the flare(s) we can determine the SO_2 emitted to the atmosphere over a specified timeframe.

With respect to the volumetric flow rate monitoring systems, we developed our proposed approach considering volumetric flow rate monitoring requirements established at refinery flares in California and Texas, vendor literature, technical articles, and information gathered from discussions with vendors. (*See* reference documents *KK* (Bay Area Air Quality Management District (BAAQMD)—documents related to consideration of proposed new regulation 12, Rule 11 Flare Monitoring at Petroleum Refineries); *LL* (final version of BAAQMD Regulation 12, Miscellaneous Standards of Performance, Rule 11, Flare Monitoring at Petroleum Refineries); *BBB* (South Coast Area Air Quality Management District (SCAQMD)—documents related to consideration of revisions to rule 1118, Control of Emissions From Refinery Flares); *CCC* (final version of SCAQMD Rule 1118, Control of Emissions From Refinery Flares); *MM* (Texas Natural Resource Conservation Commission, Chapter 115—Control of Air Pollution from Volatile Organic Compounds, Subchapter H: Highly-Reactive Volatile Organic Compounds, Division 1: Vent Gas Control); *NN* (Fluid Components International LLC (FCI), vendor literature from *www.fluidcomponents.com*); *OO* (GE Sensing, vendor literature); *PP* (''Why and How to measure flare gas'' from Flowmeter Directory (*www.flowmeterdirectory.com*)); *QQ* (''Transit-time Ultrasonic Flowmeters for Gases'' Presented at and Published in Part in the *Proc. 41st Annual CGA (Canadian Gas Association) Gas Measurement School*, Grand Okanagan, Kelowna BC, Canada, June 4–6, 2002); *RR* (''Flare Measurement 'Best Practices' To Comply With National & Provincial Regulations''); *SS* (''Ultrasonic Flowmeter Market is Expected to Grow Strongly''); *TT* (Note to Billings/Laurel SO_2 FIP File, April 7, 2004 Discussion with Peter Klorer, GE Infrastructure, Regarding Panametrics Mass Flowmeter); *HHH* (Note to Billings/ Laurel SO_2 FIP File, April 20, 2006 Discussion with Paul Calef, GE Sensing, Regarding Flare Flowmeter).) Based on what is required elsewhere and what we have learned from vendors and literature, we have determined that there is reliable technology available to continuously monitor and record the volumetric flow rate of the gas stream to a flare. Therefore, we are proposing that sources install, calibrate, maintain and operate a continuous flow monitoring system capable of measuring the total volumetric flow of the gas stream that is combusted in a flare in accordance with the specifications described below. The flow monitoring system may require one or more flow monitoring devices or flow measurements at one or more header locations if one monitor cannot measure all of the volumetric flow to a flare.

We are proposing the following volumetric flow monitoring specifications:

(1) The minimum detectible velocity of the flow monitoring device(s) shall be 0.1 feet per second (fps);

(2) The device(s) shall continuously measure the range of flow rates corresponding to velocities from 0.5 to 275 fps and have a manufacturer's specified accuracy of ±5% over the range of 1 to 275 fps;

(3) For correcting flow rate to standard conditions (defined as 68°F and 760 millimeters of mercury (mmHg)), temperature and pressure shall be monitored continuously;

(4) The temperature and pressure shall be monitored in the same location as the flow monitoring device(s) and shall be calibrated to meet accuracy specifications as follows: temperature shall be calibrated annually to within ±2.0% at absolute temperature and the pressure monitor shall be calibrated annually to within ±5.0 mmHg;

(5) Flow monitoring device(s) shall be initially calibrated, prior to installation, to demonstrate accuracy to within 5.0% at flow rates equivalent to 30%, 60% and 90% of monitor full scale; and

(6) After installation, the flow monitoring devices shall be calibrated annually according to manufacturer's specifications.[17]

With respect to measuring the total sulfur concentration, we developed our proposed approach considering concentration monitoring requirements established at refinery flares in California, vendor iterature, and information gathered from discussions with vendors. (*See* reference documents *UU* (Note to Billings/Laurel SO_2 FIP File, May 11, 2004 Discussion with Robert Hornberger, Galvanic Applied Sciences); *VV* (Galvanic Applied Sciences Inc., H_2S & Total Sulfur Analyzers, vendor literature printed from *www.galvanic.ab.ac*); *KK* (Bay Area Air Quality Management District (BAAQMD)—documents related to consideration of proposed new regulation 12, Rule 11, Flare Monitoring

[17] Volumetric flow monitors meeting the proposed volumetric flow monitoring specifications above should be able to measure the majority of volumetric flow in the gas streams to the flare. However, in rare events (e.g., such as upset conditions) the flow to the flare may exceed the range of the monitor. EPA is not suggesting that multiple monitors be installed to measure extreme flow rates that rarely occur. Rather, in the rare event that the range of the monitor is exceeded, reliable flow estimation parameters may be used to determine the volumetric flow rate to the flare. Flow determined through reliable estimation parameters will be used to calculate SO_2 emissions. In quarterly reports, sources shall indicate when reliable estimation parameters are used and how such parameters were derived.

at Petroleum Refineries); *BBB* (South Coast Area Air Quality Management District (SCAQMD)—documents related to consideration of revisions to rule 1118, Control of Emissions From Refinery Flares); *CCC* (final version of SCAQMD Rule 1118, Control of Emissions From Refinery Flares); *XX* (Note to Billings/Laurel SO_2 FIP File, May 10 and May 31, 2006 Discussions with Tom Kimbel, Analytical Systems International, Regarding Total Sulfur Analyzers); *YY* (Analytical Systems International, Continuous Sulfur Analyzer, vendor literature printed from *www.ASIWebPage.com*); *III* (Note to Billings/Laurel SO2 FIP File, April 19, 2006 Discussion with Bob Kinsella, ThermoElectron, Regarding Total Sulfur Analyzer); *JJJ* (Note to Billings/Laurel SO_2 FIP File, May 12, 2006, and June 7, 2006 Discussions with Eugene Teszler, South Coast Air Quality Management District, regarding Total Sulfur Analyzer).) Based on what is required elsewhere and what we have learned from vendors, we have determined that there is reliable technology available to continuously monitor and record the total sulfur concentration of the gas stream to a flare. Also, we are proposing that the total sulfur concentrations, rather than just H_2S concentrations, be monitored continuously. This is because we believe there are other sulfur compounds in the gas stream to a flare. The total sulfur analyzer system may require one or more total sulfur analyzers or total sulfur concentration measurements at one or more header locations if one analyzer cannot measure all of the total sulfur concentration to a flare.

Therefore, we are proposing that sources install, calibrate, maintain and operate an on-line analyzer system capable of continuously determining the total sulfur concentration of the gas stream sent to a flare. We are proposing that the continuous monitoring occur at a location(s) that is (are) representative of the gas combusted in the flare and be capable of measuring the expected range of total sulfur expected in the gas stream to the flare. Vendor literature and discussions with vendors indicates this is feasible. The total sulfur analyzer shall be installed, certified (on a concentration basis), and operated in accordance with 40 CFR part 60, Appendix B, Performance Specification 5, and be subject to and meet the quality assurance and quality control requirements (on a concentration basis) of 40 CFR part 60, Appendix F. The source shall notify EPA in writing of each Relative Accuracy Test Audit a minimum of twenty-five (25) working days prior to the actual testing.

We are proposing that the volumetric flow and total sulfur concentrations determined by the above procedures be used in calculations to determine the hourly and three hour SO_2 emissions from the flare(s).

We are proposing that each source submit for EPA review and approval a flare monitoring plan prior to establishing continuous monitors on the flare(s). Also, we are proposing that each source submit for EPA review a quality assurance/quality control (QA/QC) plan for each of the continuous monitors.

Finally, we are proposing certain quarterly reporting requirements. The quarterly reporting requirements are similar to the reporting requirements contained in the Billings/Laurel SO_2 SIP and those contained in 40 CFR 60.7(c).

B. CHS Inc.

1. Flare Requirements

The state's attainment demonstration and our subsequent attainment modeling for the FIP assume that CHS Inc.'s flare is limited to 150 pounds of SO_2 per three hour period.[18, 19] This is the limit we are proposing for CHS Inc.'s flare. Compliance with the flare emission limit will be determined as discussed in Section III.A, above.

2. Combustion Sources Emission Limits.

Three of the emission limits contained in CHS Inc.'s portion of the Billings/Laurel SO_2 SIP are combined emission limits for combustion sources. The emission limits, contained in CHS Inc.'s 1998 exhibit, are in pounds of SO_2 per 3-hour, 24-hour and one-year averaging periods.[20] Compliance with the emission limits is determined by measuring the sulfur and H_2S content of the fuels combusted (oil and fuel gas) and the flow of the fuels to the combustion sources. The state's assumption is that when the sulfur/H_2S in the fuel is combusted, all the sulfur/H_2S converts to SO_2 and is emitted to the atmosphere. By measuring sulfur/H_2S content of the fuel and the flow of the fuel to the combustion sources, the amount of SO_2 emitted per 3-hour, 24-hour and one-year averaging periods can be calculated. CHS Inc.'s 1998 exhibit also allows sour water stripper (SWS) overheads (ammonia (NH_3) and H_2S gases removed from the sour water in the sour water stripper), to be combusted in the main crude heater. When the SWS overheads are combusted in the main crude heater, compliance with the combustion source emission limits is determined by summing the SO_2 emissions calculated from the combustion of the fuels and SWS overheads. The SO_2 emissions from the SWS overheads are determined by measuring the sulfur compounds in, and the flow of, the sour water.

We were concerned that the method the state established to measure the amount of sulfur compounds in the sour water at CHS Inc. would not measure all the sulfur compounds in the sour water.[21] Specifically, we concluded that the analytical method submitted in the SIP would not measure all of the sulfur compounds in the sour water because of the potentially high concentrations of sulfur compounds; there would not be enough preservative in the sample container to prevent the loss of the sulfur compounds during sampling and analysis. (*See* reference document X.) Therefore, the emissions of SO_2 from the combustion of SWS overheads in the main crude heater could be underestimated. We concluded that the combustion source emission limits were not enforceable under all scenarios and, therefore, did not meet the requirements of section 110(a)(2)(A) of the Act. On May 22, 2003 (68 FR 27908), we limitedly approved and limitedly disapproved the combustion source emission limits and method used to measure the sulfur compounds in the sour water.

After the state adopted CHS Inc.'s 1998 and 2000 exhibits as part of the SIP, the state modified CHS Inc.'s air quality permit to prohibit the burning of ''old'' sour water stripper overheads in the FCC CO boiler and the main crude heater. *See* Air Quality Permit #1821–11, provision II.C.1. (*See* reference document B.) The state has not modified the SIP to correspond to the changes in CHS Inc.'s air quality permit.[22]

[18] See Modeling discussion in Section III.E.5, below.

[19] Our FIP assumes that CHS Inc. has only one operational flare. *See* reference documents PPP and QQQ.

[20] Section 3(A)(1)(d) of CHS Inc.'s 1998 exhibit. (*See* reference document DD for a copy of the exhibit.)

[21] For measuring the sulfur compounds in the sour water, the state established Method #6A–1 contained in attachment #2 of CHS Inc.'s 2000 exhibit. (*See* reference document EE for a copy of the exhibit.)

[22] Page 11 of the State's CHS Inc. Permit Analysis, attached to Permit #1821–11 (see reference document B) discusses the SWS and indicates that a new SWS stripper was constructed, which replaced the operation of the older existing SWS. The old SWS cannot be removed, however, and functions only as the back-up unit. The Permit Analysis further indicates that the stripper overhead gas containing H_2S and NH_3, is sent to the new SRU for sulfur recovery and incineration of NH_3. This was confirmed in a conversation with the DEQ (see reference document DDD).

To address our limited disapproval of the combustion source emission limits in the SIP, we are proposing a prohibition in the FIP on the burning of SWS overheads in the main crude heater. Prohibiting the burning of SWS overheads in the main crude heater will eliminate our concern regarding the method used to measure the amount of sulfur compounds in the sour water. We believe it is reasonable to make this proposal because the state and CHS Inc. have already agreed to such restrictions in CHS Inc.'s air quality permit.

Compliance with the prohibition to not burn SWS overheads in the main crude heater will be based on methods similar to those contained in CHS Inc.'s 1998 exhibit. Specifically, section 3(B)(3) of the 1998 exhibit requires CHS Inc. to install a chain and lock on the valve that supplies sour water stripper overheads from the ''old'' SWS to the main crude heater to insure that the valve cannot be opened unless the chain and lock are removed. Under our proposed FIP, CHS Inc. would be required to maintain the chain and lock in place and keep the valve closed at all times. CHS Inc. would be required to log and report any noncompliance with this provision.

C. ConocoPhillips

1. Flare Requirements

The state's attainment demonstration and our subsequent attainment modeling for the FIP assume that ConocoPhillips' main refinery flare is limited to 150 pounds of SO_2 per three hour period.[23] We understand that ConocoPhillips actually has two main flares—a north main flare and a south main flare—but only operates one at a time and that Jupiter Sulfur, ConocoPhillips' sulfur recovery unit (SRU), also has one flare. Correspondence from ConocoPhillips, dated February 4, 2004, indicates that the north flare is currently in use but the south flare has been used in alternating 4-year cycles, with switches at full plant turnarounds. (*See* reference document C.) Conversations with the MDEQ on September 1, 2004, confirm that only one flare is used at a time and that a section of the pipe going to the unused flare is removed during the turnaround. (*See* reference document W.) Therefore, with respect to ConocoPhillips, in lieu of establishing a separate emission limit for each main flare, we are proposing one emission limit for the main flare. At any one time, ConocoPhillips may only use either the north or south main flare.

We are proposing that compliance with the main flare emission limit at ConocoPhillips be determined by measuring the total sulfur concentration and volumetric flow rate of the gas stream to the flare. To the extent that a single monitoring location cannot be used for both the north and south main flare, ConocoPhillips will need to monitor flow and measure total sulfur concentration at more than one location to determine compliance with the main flare emission limit.

Regarding the flare at the Jupiter Sulfur Recovery facility located at ConocoPhillips, the SRU flare and SRU/ATS[24] stack, which are roughly the same height, share an emission limit in Montana's air quality permit for ConocoPhillips; the Jupiter SRU/ATS stack and the SRU flare each have an SO_2 emission limit of 25.00 lb/hr and 0.300 tons/day. Emissions from the SRU flare are only permitted during times that the ATS plant is not operating. *See* Air Quality Permit #2619–19, dated May 27, 2004, section II.B.1.a and b. (*See* reference document S.)

However, the Billings/Laurel SO_2 SIP is not clear with respect to the relationship between the SRU flare and SRU/ATS stack. The SIP contains emission limits on the Jupiter Sulfur SRU stack but does not indicate that the limits are shared between the SRU flare and SRU/ATS stack.[25] Since the SIP is not clear, we are proposing to clarify in the FIP that emissions can only be vented from the SRU flare when emissions are not being vented from the SRU/ATS stack. We believe that our proposal is consistent with what the state and ConocoPhillips intended in the SIP. First, the SRU flare and SRU/ATS stack were modeled as one point in the state's attainment demonstration. Second, Air Quality Permit #2619–19, dated May 27, 2004, indicates that emissions from the SRU flare can only occur during times that the ATS plant is not operating.

We are proposing that compliance with the SRU flare emission limit, when Jupiter Sulfur vents emissions to the SRU flare rather than the SRU/ATS stack, be determined by measuring the total sulfur concentration and volumetric flow rate of the gas stream to the flare.[26] Our proposal regarding the SRU flare supports our attainment demonstration.

D. ExxonMobil

1. Flare Requirements

The state's attainment demonstration and our subsequent attainment modeling for the FIP assume that ExxonMobil's primary process and turnaround flares are limited to 150 pounds of SO_2 per three hour period.[27] From correspondence from ExxonMobil, dated February 4, 2004, we understand that ExxonMobil has a turnaround flare that is only used about 30–40 days every five to six years, when the facility's major SO_2 source, the fluid catalytic cracking unit, is not normally operating. (*See* reference document E.) Therefore, in lieu of establishing a separate emission limit for the turnaround flare, we are proposing one combined emission limit for the primary process and turnaround flares.

Our assumption is that the flow and concentration monitoring devices installed to measure the gas stream to the primary process flare will also be able to measure the gas stream to the turnaround flare. To the extent that a single monitoring location cannot be used to measure the gas stream to both the primary process flare and the turnaround flare, we may allow alternative measures to determine volumetric flow rate and total sulfur concentrations of the gas stream to the turnaround flare if the turnaround flare is used infrequently—*e.g.*, only for refinery turnarounds once every five to six years. Such alternative measures could include using good engineering judgment to determine volumetric flow rate to the flare or manually sampling the gas stream to the flare to determine total sulfur concentrations.

2. Compliance Monitoring of Refinery Fuel Gas Combustion Emission Limits

Two of the emission limits contained in the ExxonMobil portion of the Billings/Laurel SO_2 SIP are combined emission limits for refinery fuel gas combustion sources. The emission limits, contained in ExxonMobil's 1998 and 2000 exhibits, are in pounds of SO_2 per 3-hour and 24-hour averaging periods.[28] Compliance with the emission limits is determined by measuring the H_2S content of the refinery fuel gas combusted and the flow of the fuel gas to the combustion

[23] See Modeling discussion in Section III.E.5, below.

[24] ATS stands for Ammonium Thiosulfate.

[25] See section 3(A)(3) of ConocoPhillips' 1998 exhibit. (*See* document FF for a copy of the exhibit.)

[26] Note that the SRU/ATS stack has an SO_2 CEMS and flow monitor to determine compliance when emissions are vented through that stack.

[27] See Modeling discussion in Section III.E.5, below.

[28] See sections 3(A)(1) and 3(B)(2) of ExxonMobil's 1998 and 2000 exhibits. (*See* reference documents GG and HH for copies of the exhibits.)

sources.[29] The state's assumption is that when the fuel is combusted, all the H_2S converts to SO_2 and is emitted to the atmosphere. By measuring H_2S content of the fuel and the flow of the fuel to the combustion sources, the amount of SO_2 emitted per 3-hour and 24-hour averaging periods can be calculated.

We were concerned that the method the state established to measure the H_2S concentration was not adequate under all scenarios. Specifically, we determined that the H_2S concentrations in refinery fuel gas could exceed the levels which the H_2S continuous emission monitoring system (CEMS) would be able to monitor.[30] Therefore, the emissions of SO_2 from the refinery fuel gas combustion sources could be underestimated. We concluded that the refinery fuel gas combustion sources emission limits were not enforceable under all scenarios and, therefore, did not meet the requirements of section 110(a)(2)(A) of the Act. On May 22, 2003 (68 FR 27908), we limitedly approved and limitedly disapproved the refinery fuel gas combustion emission limits and method used to measure the H_2S in the refinery fuel gas.

Because of this limited disapproval, we are proposing a new method for measuring the H_2S concentrations in the refinery fuel gas when the H_2S concentrations in the refinery fuel gas exceed the range of the H_2S CEMS. The method we are proposing is identical to the method included in CHS Inc.'s 1998 exhibit.[31]

Specifically, we are proposing that within 4 hours of the initial determination that the H_2S concentrations in the refinery fuel gas stream exceed the upper range of the H_2S CEMS, ExxonMobil shall initiate sampling of the refinery fuel gas stream at the fuel header on a once-per-three-hour-period frequency using the Tutwiler method in 40 CFR 60.648. The Tutwiler method will determine the H_2S concentration in the refinery fuel gas. We are also proposing that the Tutwiler-derived H_2S refinery fuel gas concentration be used in calculations to determine the hourly, 3-hour and 24-hour SO_2 emission rates, in pounds, from refinery fuel gas combustion. These emission rates would then be used to determine compliance with the refinery fuel gas combustion emission limits in ExxonMobil's 1998 and 2000 exhibits when the H_2S concentrations in the refinery fuel gas stream exceed the upper range of the H_2S CEMS.[32]

We are also proposing reporting requirements similar to the requirements adopted by the state for CHS Inc. and those contained in 40 CFR 60.7(c).

3. Compliance Monitoring of Coker CO-Boiler Emission Limits

Two of the emission limits contained in the ExxonMobil portion of the Billings/Laurel SO_2 SIP are emission limits on the coker CO-boiler stack. The emission limits contained in ExxonMobil's 2000 exhibit are in pounds of SO_2 per 3-hour and 24-hour averaging periods.[33] In the SIP, compliance with the emission limits is based on an equation that was derived from historical testing and CEMS data, whereby one can determine pounds of SO_2 emitted from the coker CO-boiler by multiplying a constant by the coker fresh feed rate (in barrels/day).[34]

We had three concerns with the state's empirical method for determining compliance with ExxonMobil's coker CO-boiler stack emission limits and they were as follows: (1) The empirical method did not apply, and hence there was no compliance monitoring method, when the sulfur content of the reactor feed exceeded 5.11 percent by weight. We believed the SIP should contain a compliance monitoring method for all operating scenarios; (2) The compliance monitoring equation was basically the ''best fit'' line through the test data. To be more conservative, we believed the compliance monitoring equation should be the upper bound of the 95% confidence level of the equation; and (3) Finally, since a feed-rate meter for the coker unit was required for the compliance monitoring method, the feed-rate meter should have been subject to Quality Assurance/Quality Control (QA/QC) requirements similar to those for the FCC feed-rate meter. Therefore, we concluded that the emission limits under section 3(B)(1) of ExxonMobil's 2000 exhibit were enforceable under some but not all scenarios and did not satisfy the requirements of section 110(a)(2)(A) of the Act. (*See* 67 FR 22242, at 22244, col. 2 (May 2, 2002).) On May 22, 2003 (68 FR 27908), we limitedly approved and limitedly disapproved the coker CO-boiler stack emission limits and method used to monitor compliance.

ExxonMobil's 1998 exhibit requires ExxonMobil to install portable CEMS to monitor the SO_2 and flow to the coker CO-boiler stack or implement an Alternative Monitoring Plan approved by the Department and EPA if ExxonMobil exhausts coker unit flue gas through the coker CO-boiler stack more than 336 hours in a calendar quarter.[35] ExxonMobil exceeded the 336 hours per calendar quarter, and on March 20, 2002, the state required ExxonMobil to install SO_2 and flow CEMS on the coker CO-boiler stack. On October 21, 2002, the state sent a letter to ExxonMobil indicating that the reported test results of the monitors demonstrated that the SO_2 CEMS and flow monitors met the testing requirements. (*See* reference documents T & U, respectively.)

Since SO_2 and flow CEMS have already been installed on the coker CO-boiler stack, we are proposing that these CEMS, in conjunction with the appropriate calculations mentioned below, be used to determine compliance with the emission limits established in section 3(B)(1) of ExxonMobil's 2000 exhibit. Specifically, we are proposing that ExxonMobil operate and maintain CEMS to measure SO_2 concentrations from the coker CO-boiler stack and a continuous stack flow rate monitor to measure stack gas flow rates from the coker CO-boiler stack. We are proposing that the SO_2 and flow rate CEMS meet the CEM Performance Specifications contained in sections 6(C) and (D), respectively, of ExxonMobil's 1998 exhibit, except that ExxonMobil shall notify EPA in writing of each annual Relative Accuracy Test Audit a minimum of twenty five (25) working days prior to actual testing.

We are proposing that compliance with ExxonMobil's coker CO boiler emission limits[36] be determined using the data from the CEMS mentioned above and in accordance with the appropriate calculations described in

[29] See section 4(B) of ExxonMobil's 1998 exhibit. (*See* reference document GG for a copy of the exhibit.)

[30] Section 6(B)(3) of ExxonMobil's 1998 exhibit indicates that ExxonMobil shall insure that the H_2S concentration monitor at the refinery fuel header is capable of measuring H_2S concentrations in the range of 0–1200 ppmv. (*See* document GG for a copy of the exhibit.) The information available to us indicated that the H_2S concentrations in the refinery fuel gas could exceed 1200 ppmv. (*See* reference document JJ.)

[31] See section 6(B)(3) of CHS Inc.'s 1998 exhibit. (*See* reference document DD for a copy of the exhibit.)

[32] See sections 3(A)(1) and 3(B)(2) of ExxonMobil's 1998 and 2000 exhibits. (*See* reference documents GG and HH for copies of the exhibits.)

[33] See section 3(B)(1) of ExxonMobil's 2000 exhibit. (*See* reference document HH for a copy of the exhibit.)

[34] See section 4(c) of ExxonMobil's 2000 exhibit. (*See* reference document HH for a copy of the exhibit.)

[35] See section 6(B)(4) of ExxonMobil's 1998 exhibit (*See* reference document GG for a copy of the exhibit.)

[36] See section 3(B)(1) of ExxonMobil's 2000. (*See* reference document HH for a copy of the exhibit.)

ExxonMobil's 1998 exhibit.[37] We are also proposing reporting requirements similar to the requirements adopted in the Billings/Laurel SO_2 SIP and those contained in 40 CFR 60.7(c).

E. Montana Sulphur & Chemical Company (MSCC)

1. Flare Requirements

The state's attainment demonstration and our subsequent attainment modeling for the FIP assume that MSCC's flares are limited to a combined total of 150 pounds of SO_2 per three-hour period.[38] We understand that MSCC actually has three flares at the plant that serve a common flare system. Correspondence from MSCC, dated February 4, 2004, indicates that there is an 80-foot west flare, 125-foot east flare, and 100-meter flare. (*See* reference document H.) In discussions with MSCC on March 9, 2004, we confirmed that MSCC understood that the state's 150 lbs of SO_2/3-hour limit was intended to be a ''bubble'' or combined limit for all three flares. (*See* reference document V.) Therefore, in lieu of establishing a separate emission limit for each of the three flares, we are proposing one combined emission limit for the three flares. Compliance with the flare emission limit will be determined as discussed in Section III.A, above. In the event MSCC cannot monitor all three flares from a single monitoring location, MSCC will need to establish multiple monitoring locations.

2. SRU 100-Meter Stack

On May 2, 2002, EPA disapproved SIP emission limits the state established for the sulfur recovery unit (SRU) 100-meter stack because of improper stack height credit (*see* 67 FR 22168).[39]

Because we disapproved the emission limits, we are proposing the following emission limits for the SRU 100-meter stack: emissions of SO_2 shall not exceed (a) 3,003.1 pounds per three-hour period, (b) 24,025.0 pounds per calendar day, and (c) 9,088,000.0 pounds per calendar year.[40] The emission limits for the SRU 100-meter stack are based on modeling conducted by EPA to show attainment of the SO_2 NAAQS in the Billings/Laurel area. A detailed discussion of the modeling is contained in Section III.E.5 of this document.

We are also proposing that compliance with the above emission limits be determined according to the methods established in MSCC's 1998 exhibit. Finally, we are proposing certain quarterly reporting requirements. The quarterly reporting requirements are similar to the reporting requirements contained in the Billings/Laurel SO_2 SIP and those contained in 40 CFR 60.7(c).

In the Billings/Laurel SO_2 SIP, the State of Montana adopted variable emission limits for several sources, including MSCC's SRU 100-meter stack, which depend on the ''buoyancy flux'' of the SO_2 gas plume as it exits the stack. Buoyancy flux is a function of gas flow rate and gas temperature in the stack, which varies within certain parameters. While we approved variable emission limits for several sources, other than MSCC, we did so with reservations. (*See* our July 28, 1999, proposed rulemaking action on the Billings/Laurel SO_2 SIP, 64 FR 40791, starting at 64 FR 40794, col. 3, and our May 2, 2002, final rulemaking action, 67 FR 22168, starting 67 FR 22206, col. 2, for a full discussion of our concerns with the variable emission limit concept.) We are proposing fixed emission limits, rather than variable emission limits, on MSCC's SRU 100-meter stack because they are less complicated to model, monitor, and enforce. For example, the state's original modeling effort to determine emissions limits that included three variable emission limited sources required a total of 1320 modeling runs. A conventional SIP modeling analysis with fixed emission limits for each source requires only a single modeling run. Additionally, based on actual emissions data for MSCC's SRU 100-meter stack for 2003, 2004 and 2005, MSCC can meet the fixed 3-hour and 24-hour emission limits we are proposing (see reference documents FFF and GGG).

3. SRU 30-Meter Stack

On May 2, 2002, EPA limitedly approved and limitedly disapproved the SRU 30-meter stack emission limits because the SIP did not adequately limit the fuel burned in the boilers and heaters that exhaust through the SRU 30-meter stack, and did not provide a monitoring method that would make the emission limits practically enforceable (*see* 67 FR 22168, at 22171).[41]

Because of this limited disapproval, we are proposing that H_2S concentrations in the fuel gas burned in the boilers and heaters while any boiler or heater is exhausting through the SRU 30-meter stack be limited to 100 ppm or less, averaged over a three-hour period. Our information indicates that limiting H_2S concentrations to this level should assure compliance with the SRU 30-meter stack emission limits. Worst-case conditions would be when all the heaters and boilers are exhausting to the SRU 30-meter stack, operating at maximum heat input capacity, and using fuel with the lowest nominal fuel gas value. Under these conditions, MSCC would be using the maximum volume of fuel, and potential emissions of SO_2 from the SRU 30-meter stack would be greatest.

Using a heat input capacity value of 83 MM Btu/hour and a nominal fuel gas value of 350 Btu/scf, we determined that a limit of 100 ppm H_2S would just ensure compliance with the SRU 30-meter stack's 12.0 pounds of SO_2/3-hour limit.[42] [43] Since the daily and annual limits are merely multiples of the 3-hour limit, this concentration limit would also ensure compliance with the daily and annual limits.

To determine compliance with the 100 ppm H_2S limit, we are proposing that any time fuel other than natural gas is burned in a heater or boiler that exhausts to the SRU 30-meter stack, MSCC must measure the H_2S content of the fuel burned within one hour from when a heater or boiler begins exhausting to the SRU 30-meter stack and on a once-per-three-hour-period frequency until no heater or boiler is exhausting to the SRU 30-meter stack. We are proposing that MSCC use a portable H_2S monitor to determine the H_2S content of the fuel burned. The monitor must have a range of 0–500 ppm of H_2S and an accuracy of $+/-2\%$ of full scale (*i.e.*, the design range of the monitor—in this case 500 ppm). (*See*

[37] See sections 2(A)(1), (8), (11)(a), and (16) of ExxonMobil's 1998 exhibit. (*See* reference document GG for a copy of the exhibit.)

[38] See Modeling discussion in Section III.E.5, below.

[39] The emission limits were contained in sections 3(A)(1)(a) and (b) and 3(A)(3) of MSCC's 1998 exhibit. (*See* reference document II for a copy of the exhibit.)

[40] Our FIP proposes to retain the calendar year emission limit contained in section 3(A)(1)(a)(iv) of MSCC's 1998 exhibit. (*See* reference document II.)

[41] The emission limit is contained in section 3(A)(2) of MSCC's 1998 exhibit. (*See* reference document II for a copy of the exhibit.)

[42] See reference documents TTT and UUU. Reference document TTT contains information supplied by MDEQ, including heat input capacities for the various heaters and boilers, and nominal fuel gas values. These are the values we used in our calculations in reference document UUU.

[43] The state's technical review document for MSCC's Title V operating permit indicates that the maximum heat input capacity for some of the heaters and boilers could be greater than their ''Bigelow'' ratings (see reference document VVV). To ensure attainment even at potentially higher heat input capacities, we modeled the SRU 30-meter stack at an emission rate of 15 lbs of SO_2/3-hours (0.63 g/s), 25% higher than the 12 lbs of SO_2/3-hour emission limit. At 0.63 g/s, we still modeled attainment of the 3-hour and 24-hour SO_2 NAAQS. Thus, the 100 ppm H_2S concentration would be consistent with attainment even if the total heat input capacity of the heaters and boilers were significantly higher.

reference documents ZZ and AAA for vendor literature and discussion notes with vendor.)

While we are proposing the foregoing approach for determining compliance with the SRU 30-meter stack emission limits, we are soliciting input on whether we should promulgate a different compliance determining method. One alternative approach would involve the measurement of H_2S concentrations as described above, but would not create a concentration limit. MSCC would be required to install a fuel gas flow rate monitor that would measure the flow of all the fuel burned in the heaters and boilers, and keep logs of (a) the dates and time periods that emissions were exhausted through the SRU 30-meter stack, (b) the heaters and boilers exhausting to the SRU 30-meter stack, (c) all the heaters and boilers operating during such periods, and (d) the type of fuel that is burned in any heater or boiler at the time that emissions were exhausted to the SRU 30-meter stack.

SO_2 emissions from the SRU 30-meter stack would be calculated based on the H_2S content of the fuel burned and the flow of the fuel to the heaters and boilers. Since the fuel flow meter would be installed in the fuel gas header and would measure all the fuel gas burned regardless of whether or not all the heaters or boilers were exhausting to the SRU 30-meter stack, the calculations of SO_2 emissions from the SRU 30-meter stack would be pro-rated based on the estimated percentage of fuel burned in the heaters and boilers exhausting to the SRU 30-meter stack versus fuel burned in all operating heaters and boilers.

We envision that one way to calculate this pro-ration factor would be to divide the maximum heat input capacity of the heaters and boilers exhausting to the SRU 30-meter stack by the maximum heat input capacity of all operating heaters and boilers during such periods. In order to ensure compliance with the three-hour emission limits, this pro-ration factor would have to be calculated on an hourly or, at most, three-hourly basis.

We solicit input on other possible approaches for determining compliance with the SRU 30-meter stack emission limits.

Finally, we are proposing quarterly reporting requirements. The quarterly reporting requirements are similar to the reporting requirements contained in the Billings/Laurel SO_2 SIP and those contained in 40 CFR 60.7(c).

4. Combined SO_2 Emission Limit From the Auxiliary Vent Stacks

On May 2, 2002, EPA disapproved the combined SO_2 emission limit from the auxiliary vent stacks because the SIP did not restrict the sulfur content of the fuel burned in the heaters and boilers when they exhaust through the auxiliary vent stacks, and lacked a monitoring method that would make the emission limit practically enforceable (*see* 67 FR 22168, at 22171).[44] Because of this disapproval, we are proposing combined SO_2 emission limits for the auxiliary vent stacks and a method for determining compliance with the emission limits.

The emission limits we are proposing are based on the emission limit in MSCC's 1998 exhibit[45] and apply to the auxiliary vent stacks associated with the Railroad Boiler, the H–1 Unit, the H1–A Unit, the H1–1 Unit, and the H1–2 Unit. The issues associated with monitoring compliance with these limits are essentially the same as those associated with monitoring compliance with the SRU 30-meter stack emission limits (*see* 67 FR 22168, at 22202, May 2, 2002, reference document AA). Thus, we are proposing the same approach for monitoring compliance with these emission limits as we describe in section III.E.3, above—H_2S concentrations in the fuel gas burned in the boilers and heaters while any boiler or heater is exhausting to the auxiliary vent stacks would be limited to 100 ppm or less, averaged over a three-hour period, and the same monitoring requirements would apply. Similarly, we are soliciting input on whether we should promulgate a different compliance determining method, as described in section III.E.3 above.

Finally, we are proposing quarterly reporting requirements. The quarterly reporting requirements are similar to reporting requirements contained in the Billings/Laurel SO_2 SIP and those contained in 40 CFR 60.7(c).

5. Modeling To Support Emission Limits

To establish MSCC's SRU 100-meter stack emission limits, EPA re-ran Montana's 1996 SIP modeling analysis with some modifications explained below. Our intent was to retain the state's original attainment modeling analysis (which supports the emission limits established for sources in the Billings/Laurel SO_2), but modify the files as necessary to establish SO_2 emission limits at MSCC's SRU 100-meter stack based on a 65 meter stack height credit and a fixed buoyancy flux. We used the same dispersion model that the state used (per EPA 1996 modeling guidance (*i.e.*, ISC2/Complex1)) and the same meteorological data.

There were several minor modeling input changes made for some of the sources. In December 2003, EPA sent letters (pursuant to section 114 of the Act) to all of the sources in the Billings/Laurel area requesting clarification on the appropriate emission point parameters for modeling. (*See* reference documents L through R.) Based on the responses to the 114 letters, we modified some of the emission point modeling parameters contained in the state's modeling analysis. The June 2006 Technical Support Document titled ''Dispersion Modeling to Support Sulfur Dioxide (SO_2) Emission Limits in Federal Implementation Plan (FIP) for Billings/Laurel, Montana'' (*see* reference document WW) identifies the emission point modeling parameters used in our modeling analysis. The document also identifies changes that were recommended by sources but for various reasons were not incorporated into EPA's modeling. An electronic record (CD) of EPA's modeling input and output files is contained in the docket (*see* reference document EEE).

In the state's 1996 modeling, MSCC's SRU 100-meter stack was modeled with a 97 meter stack height credit and a variable emission limit linked to 10 stack buoyancy flux values. We modeled MSCC's SRU 100-meter stack with a 65 meter stack height credit and a single representative buoyancy flux value. Buoyancy flux is a function of gas flow rate and temperature in the stack. The stack temperature we used in our modeling, 540.0°K, was the mean stack temperature measured with CEMS from October 1, 2001, to September 30, 2003. The mean stack velocity we used in our modeling, 14.0 m/s, was back-calculated from the buoyancy flux equation using the buoyancy flux and temperature values from October 1, 2001, to September 30, 2003.[46] [47] It is EPA's modeling practice to select mean values from historical data because, unless there is some change in plant

[44] The emission limits are contained in section 3(A)(4) of MSCC's 1998 exhibit. (*See* document II for a copy of the exhibit.)

[45] The emission limit is contained in section 3(A)(4) of MSCC's 1998 exhibit. (*See* document II for a copy of the exhibit.)

[46] The buoyancy flux (F) is defined as: $F = (2.45\ VD^2\ (T_s\text{-}T))/T_s$. Where: F = buoyancy flux in m^4/m^3; V = stack gas exit velocity in meters per second at actual conditions; D = inside stack-top diameter in meters (1.07 m); T_s = stack gas temperature in Kelvin; and T = ambient air temperature in Kelvin (assumed at 281.2 °K). (See reference document II)

[47] See reference document FFF for temperature and buoyancy flux values.

configuration, future operations are likely to reflect similar values.

It should be noted that with the changes mentioned above, the 24-hour highest receptor point modeled showed the 24-hour and 3-hour SO_2 high-second-high (HSH) values to be 365 μg/m³ and 1243.6 μg/m³, respectively. The 3-hour highest receptor point modeled showed the 3-hour SO_2 HSH value to be 1291.5 μg/m³. The SO_2 24-hour and 3-hour SO_2 NAAQS are 365 μg/m³ and 1300 μg/m³, respectively. Therefore, the FIP shows attainment of the NAAQS.

When we modeled the four process flares at 500 lbs/3-hour period instead of 150 lbs/3-hour period, the 3-hour HSH concentration at the highest 3-hour receptor point only increased by 2 μg/m³, to 1293.5 μg/m³. This means that even if the four process flares were allowed to emit SO_2 at 500 lbs/3-hour period, the FIP would still show attainment of the 3-hour NAAQS. (We modeled this alternative emissions rate because, as discussed earlier, we are inviting comment on whether we should consider an emissions limit for the process flares of 500 lbs SO_2/calendar day instead of 150 lbs/3-hour period. We modeled the 500 pounds of SO_2 emissions over a 3-hour period to ensure attainment of the 3-hour SO_2 NAAQS.)

In the state's modeling analysis submitted with the SIP, the highest receptor point modeled had 24-hour and 3-hour HSH SO_2 values of 354 μg/m³ and 1245 μg/m³, respectively. This difference in FIP and SIP modeling outputs is due largely to the fact that EPA modeled MSCC's 100-meter SRU stack at 65 meters. In addition, in their responses to the section 114 letters mentioned above, some sources provided updated locations of emission points. (It was not that emission points had moved; the technology used to describe the emission point locations had changed.) Therefore, peak receptor locations changed in the FIP versus SIP modeling.

IV. Request for Public Comment

EPA is soliciting public comment on all aspects of this proposed FIP. Interested parties should submit comments according to the procedures outlined earlier in the **ADDRESSES** section and in Part (I)(A) of the **SUPPLEMENTARY INFORMATION** section. Comments received on or before September 11, 2006 will be considered in the final action taken by EPA.

V. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review

Under Executive Order 12866, 58 FR 51735 (October 4, 1993), all ''regulatory actions'' that are ''significant'' are subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. A ''regulatory action'' is defined as ''any substantive action by an agency (normally published in the **Federal Register**) that promulgates or is expected to result in the promulgation of a final rule or regulation, including * * * notices of proposed rulemaking.'' A ''regulation or rule'' is defined as ''an agency statement of general applicability and future effect, * * *''

The proposed FIP is not subject to OMB review under E.O. 12866 because it applies to only four specifically named facilities and is therefore not a rule of general applicability. Thus, it is not a ''regulatory action'' under E.O. 12866, and was not submitted to OMB for review.

B. Paperwork Reduction Act

Under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, OMB must approve all ''collections of information'' by EPA. The Act defines ''collection of information'' as a requirement for ''answers to * * * identical reporting or recordkeeping requirements imposed on ten or more persons * * *'' 44 U.S.C. 3502(3)(A). Because the proposed FIP only applies to four companies, the Paperwork Reduction Act does not apply.

C. Regulatory Flexibility Act

Under the Regulatory Flexibility Act (RFA), 5 U.S.C. section 601 *et seq.*, EPA generally must prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless EPA certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions. 5 U.S.C. §§ 603, 604 and 605(b).

This proposed FIP will not have a significant economic impact on a substantial number of small entities because this proposed FIP applies to only four sources (CHS Inc., ConocoPhillips, ExxonMobil and MSCC) in the Billings/Laurel, Montana area. Therefore, I certify that this action will not have a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995, Public Law 04–4, establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed rules and for final rules for which EPA published a notice of proposed rulemaking, if those rules contain ''federal mandates'' that may result in the expenditure by state, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year. If section 202 requires a written statement, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives. Under section 205, EPA must adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule, unless the Administrator publishes with the final rule an explanation why EPA did not adopt that alternative. The provisions of section 205 do not apply when they are inconsistent with applicable law. Section 204 of UMRA requires EPA to develop a process to allow elected officers of state, local, and tribal governments (or their designated, authorized employees), to provide meaningful and timely input in the development of EPA regulatory proposals containing significant Federal intergovernmental mandates.

EPA has determined that the proposed FIP contains no federal mandates on state, local or tribal governments, because it will not impose any enforceable duties on any of these entities. EPA further has determined that the proposed FIP will not result in the expenditure of $100 million or more by the private sector in any one year. Although the proposed FIP would impose enforceable duties on entities in the private sector, the costs are expected to be less than $100 million in any one year. Consequently, sections 202, 204, and 205 of UMRA do not apply to the proposed FIP.

Before EPA establishes any regulatory requirements that might significantly or uniquely affect small governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that the proposed FIP will not significantly or uniquely affect small governments, because it imposes no requirements on small governments. Therefore, the requirements of section 203 do not apply to the proposed FIP.

E. Executive Order 13132, Federalism

Executive Order 13132, *Federalism* (64 FR 43255, August 10, 1999), revokes and replaces Executive Orders 12612 (Federalism) and 12875 (Enhancing the Intergovernmental Partnership). Executive Order 13132 requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

The proposed rule does not have federalism implications. This FIP will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This rule proposes standards appropriate for four companies in the Billings/Laurel, Montana area, and thus does not directly affect any state or local government. It does not alter the relationship or the distribution of power and responsibilities established by the Clean Air Act. Thus, Executive Order 13132 does not apply to this rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communication between EPA and State and local governments, EPA specifically solicits comments on the proposed rule from State and local officials.

F. Executive Order 13175, Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.''

This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes as specified in Executive Order 13175. This Action does not involve or impose any requirements that affect Indian Tribes. Thus, Executive Order 13175 does not apply to this rule.

EPA specifically solicits comment on this proposed rule from tribal officials.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

Protection of Children from Environmental Health Risks and Safety Risks (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This proposed FIP is not subject to the Executive Order because it is not economically significant as defined in Executive Order 12866. Further, EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This proposed FIP is not subject to Executive Order 13045 because it implements a previously promulgated health and safety based Federal standard.

H. Executive Order 13211, Actions That Significantly Affect Energy Supply, Distribution, or Use

This rule is not subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995, Public Law No. 104–113 (15 U.S.C. 272 note), directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary standards.

While the proposed rulemaking involves technical standards, no voluntary consensus standards have been identified. EPA welcomes comments on this aspect of the proposed FIP and, specifically, invites the public to identify potentially-applicable voluntary consensus standards and to explain why such standards should be used in this regulation.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements, Sulfur oxides.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: June 29, 2006.

Kerrigan G. Clough,

Acting Regional Administrator, Region 8.

For reasons stated in the preamble, 40 CFR part 52 is proposed to be amended as follows:

PART 52—[AMENDED]

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart BB—Montana

2. Subpart BB is proposed to be amended by adding § 52.1392 to read as follows:

§ 52.1392. Federal Implementation Plan for the Billings/Laurel Area.

(a) *Applicability.* This section applies to the owner(s) or operator(s), including any new owner(s) or operator(s) in the event of a change in ownership or operation, of the following facilities in the Billings/Laurel, Montana area: CHS Inc. Petroleum Refinery, Laurel Refinery, 803 Highway 212 South, Laurel, MT; ConocoPhillips Petroleum Refinery, Billings Refinery, 401 South 23rd St., Billings, MT; ExxonMobil Petroleum Refinery, 700 ExxonMobil Road, Billings, MT; and Montana

Sulphur & Chemical Company, 627 Exxon Road, Billings, MT.

(b) *Scope.* The facilities listed in paragraph (a) of this section are also subject to the Billings/Laurel SO_2 SIP, as approved at 40 CFR 52.1370(c)(46) and (52). In cases where the provisions of this FIP address emissions activities differently or establish a different requirement than the provisions of the approved SIP, the provisions of this FIP take precedence.

(c) *Definitions.* For the purpose of this section, we are defining certain words or initials as described in this paragraph. Terms not defined below that are defined in the Clean Air Act or regulations implementing the Clean Air Act, shall have the meaning set forth in the Clean Air Act or such regulations.

(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 within the calendar year.

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

(3) *Clock Hour* means a twenty-fourth (1/24) of a calendar day; specifically any of the standard 60-minute periods in a day that are identified and separated on a clock by the whole numbers one through twelve.

(4) *Continuous Emission Monitoring System or CEMS* means all continuous concentration and volumetric flow rate monitors, associated data acquisition equipment, and all other equipment necessary to meet the requirements of this section for continuous monitoring.

(5) *Daily Emissions* (i) means the amount of SO_2 emitted in a calendar day, expressed in pounds per day rounded to the nearest tenth of a pound.

Where:

Daily emissions = Σ Three hour emissions within a calendar day.

(ii) Each calendar day is comprised of eight non-overlapping three-hour periods. The three hour emissions from all the three-hour periods in a calendar day shall be used to determine the day's emissions.

(6) *Exhibit* means for a given facility named in 40 CFR 52.1392(a), exhibit A to the stipulation of the Montana Department of Environmental Quality and that facility, adopted by the Montana Board of Environmental Review on either June 12, 1998 or March 17, 2000.

(7) *1998 Exhibit* means for a given facility named in 40 CFR 52.1392(a), the exhibit adopted by the Montana Board of Environmental Review on June 12, 1998.

(8) *2000 Exhibit* means for a given facility named in 40 CFR 52.1392(a), the exhibit adopted by the Montana Board of Environmental Review on March 17, 2000.

(9) *Flare* means a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. This term includes both ground and elevated flares.

(10) The initials *Hg* mean mercury.

(11) *Hourly* means or refers to each clock hour in a calendar day.

(12) *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 CEMS and source per clock hour.

Exclusive of the above definition, an hourly average may be determined with two 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 CEMS shall have a minimum of one (1) data point value; however, each CEMS shall be operated such that all valid data points acquired in any 15-minute block shall be used to determine the 15-minute block's reported concentration and flow rate.

(13) *Hourly Emissions* means the pounds per clock hour of SO_2 emissions from a source (flare, stack, fuel oil system, sour water system, or fuel gas system) determined using hourly averages and rounded to the nearest tenth of a pound.

(14) The initials *H_2S* mean hydrogen sulfide.

(15) The initials *MBER* mean the Montana Board of Environmental Review.

(16) The initials *MDEQ* mean the Montana Department of Environmental Quality.

(17) The initials *mm* mean millimeters.

(18) The initials *MSCC* mean the Montana Sulphur & Chemical Company.

(19) The initials *ppm* mean parts per million.

(20) The initials *SCFH* mean standard cubic feet per hour.

(21) The initials *SCFM* mean standard cubic feet per minute.

(22) *Standard Conditions* means (a) 20 °C (293.2 °K, 527.7 °R, or 68.0 °F) and 1 atmosphere pressure (29.92 inches Hg or 760 mm Hg) for stack and flare gas emission calculations, and (b) 15.6 °C (288.7 °K, 520.0 °R, or 60.3 °F) and 1 atmosphere pressure (29.92 inches Hg or 760 mm Hg) for refinery fuel gas emission calculations.

(23) The initials *SO_2* mean sulfur dioxide.

(24) The initials *SWS* mean sour water stripper.

(25) *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 tenth of a pound.

Where:

Three hour emissions = Σ Hourly emissions within the three hour period.

(26) *Three hour period* means any of the eight non-overlapping three-hour periods in a calendar day: midnight to 3 a.m., 3 a.m. to 6 a.m., 6 a.m. to 9 a.m., 9 a.m. to noon, noon to 3 p.m., 3 p.m. to 6 p.m., 6 p.m. to 9 p.m., 9 p.m. to midnight.

(27) *Turnaround* means a planned activity involving shutdown and startup of one or several process units for the purpose of performing periodic maintenance, repair, replacement of equipment or installation of new equipment.

(28) *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 of ConocoPhillips', CHS Inc.'s, ExxonMobil's, and MSCC's 1998 exhibits, respectively, and 40 CFR 52.1392.

(d) CHS Inc. emission limits and compliance determining methods.

(1) *Introduction:* The provisions for CHS Inc. cover the following units:

(i) The flare.

(ii) Combustion sources, which consist of those sources identified in the combustion sources emission limit in section 3(A)(1)(d) of CHS Inc.'s 1998 exhibit.

(2) *Flare requirements:* (i) *Emission limit:* The total emissions of SO_2 from the flare shall not exceed 150.0 pounds per three hour period.

(ii) *Compliance determining method:* Compliance with the emission limit in 40 CFR 52.1392(d)(2)(i) shall be determined in accordance with 40 CFR 52.1392(h).

(3) *Combustion sources:* (i) *Restrictions:* Sour water stripper overheads (ammonia (NH3) and H2S gases removed from the sour water in the sour water stripper) shall not be burned in the main crude heater. At all times, CHS Inc. shall keep a chain and lock on the valve that supplies sour water stripper overheads from the old

sour water stripper to the main crude heater and shall keep such valve closed.

(ii) *Compliance determining method:* CHS Inc. shall log and report any noncompliance with the requirements of 40 CFR 52.1392(d)(3)(i).

(4) *Data reporting requirements:* (i) CHS Inc. shall submit quarterly reports beginning with the first calendar quarter following [DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**]. The quarterly reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to the Air Program Contact at EPA's Montana Operations Office, Federal Building, 10 West 15th Street, Suite 3200, Helena, MT 59626. The quarterly report shall be certified for accuracy in writing by a responsible CHS Inc. official. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written hard copy data summary report.

(ii) The electronic report submitted to the EPA shall be on magnetic or optical media, and such submittal shall follow the reporting format of electronic data being submitted to the MDEQ. The EPA may modify the reporting format delineated in this section, and thereafter CHS Inc. shall follow the revised format. In addition to submitting the electronic quarterly reports to the EPA, CHS Inc. shall also record, organize and archive for at least five years the same data, and upon request by the EPA, CHS Inc. shall provide the EPA with any data archived in accordance with this provision. The electronic report shall contain the following:

(A) Hourly average total sulfur concentrations in ppm in the gas stream to the flare;

(B) Hourly average volumetric flow rates in SCFH of the gas stream to the flare;

(C) Hourly average temperature (in (F) and pressure (in mm or inches of Hg) of the gas stream to the flare;

(D) Hourly emissions from the flare in pounds per clock hour; and

(E) Daily calibration data for flare CEMS.

(iii) The quarterly written report format submitted to the EPA shall contain the following information:

(A) Three hour emissions in pounds per three hour period from the flare;

(B) The results of the quarterly Cylinder Gas Audits (CGA) or Relative Accuracy Audits (RAA) required by 40 CFR part 60, Appendix F, and the annual Relative Accuracy Test Audit (RATA) for the total sulfur analyzer(s);

(C) For all periods of flare volumetric flow rate monitoring system or total sulfur analyzer system downtime, the written report shall identify:

(*1*) Dates and times of downtime;

(*2*) Reasons for downtime; and

(*3*) Corrective actions taken to mitigate downtime;

(D) For each three hour period in which the flare emission limit is exceeded, the written report shall identify:

(*1*) The date, start time, and end time of the excess emissions;

(*2*) Total hours of operation with excess emissions, the hourly emissions, and the three hour emissions;

(*3*) All information regarding reasons for operating with excess emissions; and

(*4*) Corrective actions taken to mitigate excess emissions.

(E) For all periods that the range of the volumetric flare flow rate monitor(s) is (are) exceeded, the quarterly written report shall identify:

(*1*) Date and time when the range of the flare volumetric flow monitor(s) is (are) exceeded and

(*2*) The reliable estimation parameters used to determine flow in the gas stream to the flare and how the estimation parameters were derived.

(F) The date and time of any noncompliance with the requirements of 40 CFR 52.1392(d)(3)(i).

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

(e) ConocoPhillips emission limits and compliance determining methods.

(1) *Introduction:* The provisions for ConocoPhillips cover the following units:

(i) The main flare, which consists of two flares—the north flare and the south flare—that are operated on alternating schedules. These flares are referred to herein as the north main flare and south main flare, or generically as the main flare.

(ii) The Jupiter Sulfur SRU flare, which is the flare at Jupiter Sulfur, ConocoPhillips' sulfur recovery unit.

(2) *Flare requirements:* (i) *Emission limits:* (A) Emissions of SO_2 from the main flare (which can be emitted from either the north or south main flare, but not both at the same time) shall not exceed 150.0 pounds three hour period.

(B) Emissions of SO_2 from the Jupiter Sulfur SRU flare and the Jupiter Sulfur SRU/ATS stack (also referred to as the Jupiter Sulfur SRU stack) shall not exceed 75.0 pounds per three hour period, 600.0 pounds per calendar day, and 219,000 pounds per calendar year. At any one time, ConocoPhillips may only vent emissions from either the Jupiter Sulfur SRU flare or the Jupiter Sulfur SRU/ATS stack, but not both simultaneously.

(ii) *Compliance determining method:* (A) Compliance with the emission limit in 40 CFR 52.1392(e)(2)(i)(A) shall be determined in accordance with 40 CFR 52.1392(h). In the event that a single monitoring location cannot be used for both the north and south main flare, ConocoPhillips shall monitor the flow and measure the total sulfur concentration at more than one location in order to determine compliance with the main flare emission limit. ConocoPhillips shall log and report any instances when emissions are vented from the north main flare and south main flare simultaneously.

(B) Compliance with the emission limits and requirements in 40 CFR 52.1392(e)(2)(i)(B) shall be determined pursuant to ConocoPhillips' 1998 exhibit (*see* section 4(A) of the exhibit) for the Jupiter Sulfur SRU/ATS stack and in accordance with 40 CFR 52.1392(h) for the Jupiter Sulfur SRU flare. ConocoPhillips shall log and report any instances when emissions are vented from the Jupiter Sulfur SRU flare and the Jupiter Sulfur SRU/ATS stack simultaneously.

(3) *Data reporting requirements:* (i) ConocoPhillips shall submit quarterly reports on a calendar year basis, beginning with the first calendar quarter following [DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**]. The quarterly reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to the Air Program Contact at EPA's Montana Operations Office, Federal Building, 10 West 15th Street, Suite 3200, Helena, MT 59626. The quarterly report shall be certified for accuracy in writing by a responsible ConocoPhillips official. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written hard copy data summary report.

(ii) The electronic report submitted to the EPA shall be on magnetic or optical media, and such submittal shall follow the reporting format of electronic data being submitted to the MDEQ. The EPA may modify the reporting format delineated in this section, and thereafter ConocoPhillips shall follow the revised format. In addition to submitting the electronic quarterly reports to the EPA, ConocoPhillips shall also record, organize and archive for at least five years the same data, and upon request by the EPA, ConocoPhillips shall provide the EPA with any data archived in accordance with this provision. The electronic report shall contain the following:

(A) Hourly average total sulfur concentrations in ppm in the gas stream to the ConocoPhillips main flare and Jupiter Sulfur SRU flare;

(B) Hourly average volumetric flow rates in SCFH of the gas streams to the ConocoPhillips main flare and Jupiter Sulfur SRU flare;

(C) Hourly average temperature (in °F) and pressure (in mm or inches of Hg) of the gas streams to the ConocoPhillips main flare and Jupiter Sulfur SRU flare;

(D) Hourly emissions in pounds per clock hour from the ConocoPhillips main flare and Jupiter Sulfur SRU flare; and

(E) Daily calibration data for the flare CEMS.

(iii) The quarterly written report submitted to the EPA shall contain the following information:

(A) Three hour emissions in pounds per three hour period from the ConocoPhillips main flare and Jupiter Sulfur SRU flare;

(B) The results of the quarterly Cylinder Gas Audits (CGA) or Relative Accuracy Audits (RAA) required by 40 CFR part 60, Appendix F, and the annual Relative Accuracy Test Audit (RATA) for total sulfur analyzer(s);

(C) For all periods of flare volumetric flow rate monitoring system or total sulfur analyzer system downtime, the written report shall identify:

(*1*) Dates and times of downtime;

(*2*) Reasons for downtime; and

(*3*) Corrective actions taken to mitigate downtime;

(D) For each three hour period in which a flare emission limit is exceeded, the written report shall identify:

(*1*) The date, start time, and end time of the excess emissions;

(*2*) Total hours of operation with excess emissions, the hourly emissions, and the three hour emissions;

(*3*) All information regarding reasons for operating with excess emissions; and

(*4*) Corrective actions taken to mitigate excess emissions.

(E) For all periods that the range of the volumetric flare flow rate monitor(s) is (are) exceeded, the quarterly written report shall identify:

(*1*) Date and time when the range of the flare volumetric flow monitor(s) is (are) exceeded and

(*2*) The reliable estimation parameters used to determine flow in the gas stream(s) to the flare and how the estimation parameters were derived.

(F) Identification of dates, times, and duration of any instances when emissions are vented from the north and south main flares simultaneously or from the Jupiter Sulfur SRU flare and the Jupiter Sulfur SRU/ATS stack simultaneously.

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

(f) ExxonMobil emission limits and compliance determining methods:

(1) *Introduction:* The provisions for ExxonMobil cover the following units:

(i) The Primary process flare and the Turnaround flare. The Primary process flare is the flare normally used by ExxonMobil. The Turnaround flare is the flare ExxonMobil uses for about 30–40 days every five to six years when the facility's major SO_2 source, the fluid catalytic cracking unit, is not normally operating.

(ii) The following refinery fuel gas combustion units: the 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, standby boiler house (B–8 boiler), and coker CO-boiler (only when the Yellowstone Energy Limited Partnership (YELP) facility is receiving ExxonMobil coker unit flue gas or whenever the ExxonMobil coker is not operating).

(iii) Coker CO-boiler stack.

(2) *Flare requirements:* (i) *Emission limit:* The total combined emissions of SO_2 from the Primary process and Turnaround refinery flares shall not exceed 150.0 pounds per three hour period.

(ii) *Compliance determining method:* Compliance with the emission limit in 40 CFR 52.1392(f)(2)(i) shall be determined in accordance with 40 CFR 52.1392(h). If volumetric flow monitoring device(s) installed and concentration monitoring methods used to measure the gas stream to the Primary Process flare cannot measure the gas stream to the Turnaround flare, ExxonMobil may apply to EPA for alternative measures to determine the volumetric flow rate and total sulfur concentration of the gas stream to the Turnaround flare. Before EPA will approve such alternative measures, ExxonMobil must agree that the Turnaround flare will be used only during refinery turnarounds of limited duration and frequency—no more than 60 days once every five years—which restriction shall be considered an enforceable part of this FIP. Such alternative measures may consist of reliable flow estimation parameters to estimate volumetric flow rate and manual sampling of the gas stream to the flare to determine total sulfur concentrations, or such other measures that EPA finds will provide accurate estimations of SO2 emissions from the Turnaround flare.

(3) *Refinery fuel gas combustion requirements:* (i) *Emission limits:* The applicable emission limits are contained in section 3(A)(1) of ExxonMobil's 2000 exhibit and section 3(B)(2) of ExxonMobil's 1998 exhibit.

(ii) *Compliance determining method:* For the limits referenced in 40 CFR 52.1392(f)(3)(i), the compliance determining methods specified in section 4(B) of ExxonMobil's 1998 exhibit shall be followed except when the H_2S concentration in the refinery fuel gas stream exceeds 1200 ppmv as measured by the H_2S CEMS required by section 6(B)(3) of ExxonMobil's 1998 exhibit (the H_2S CEMS.) When such value is exceeded, the following compliance monitoring method shall be employed:

(A) ExxonMobil shall measure the H_2S concentration in the refinery fuel gas according to the procedures in 40 CFR 52.1392(f)(3)(ii)(B) and calculate the emissions according to the equations in 40 CFR 52.1392(f)(3)(ii)(C).

(B) Within 4 hours after the H_2S CEMS measures an H_2S concentration in the fuel gas stream greater than 1200 ppmv, ExxonMobil shall initiate sampling of the fuel gas stream at the fuel header on a once-per-three-hour-period frequency using the Tutwiler method contained in 40 CFR 60.648. ExxonMobil shall continue to use the Tutwiler method at this frequency until the H_2S CEMS measures an H_2S concentration in the fuel gas stream equal to or less than 1200 ppmv continuously over a three-hour period.

(C) When the Tutwiler method is required, SO_2 emissions from refinery fuel gas combustion shall be calculated as follows: the Hourly emissions shall be calculated using equation 1, Three hour emissions shall be calculated using equation 2, and the Daily emissions shall be calculated using equation 3.

Equation 1: $E_H = K^* C_H{}^*Q_H$

Where:

E_H = Refinery fuel gas combustion hourly emissions in pounds per hour, rounded to the nearest tenth of a pound;

K = 1.688×10^{-7} in (pounds/standard cubic feet (SCF))/parts per million (ppm);

C_H = Fuel gas H_2S concentration in ppm determined by the Tutwiler method as required by 40 CFR 52.1392(f)(3)(ii)(B) (since only one sample is taken every three (3) hours, the value for such sample shall be substituted for each hour of the 3-hour period during which the sample is taken); and

Q_H = actual fuel gas firing rate in standard cubic feet per hour (SCFH), as measured by the monitor required by section 6(B)(8) of ExxonMobil's 1998 exhibit.

Equation 2: (Refinery fuel gas combustion three hour emissions) = Σ (Hourly emissions within the three-hour period as determined by equation 1).

Equation 3: (Refinery fuel gas combustion daily emissions) = Σ (Three hour emissions within the day as determined by equation 2).

(4) *Coker CO-boiler stack requirements.*

(i) *Emission limits:* When ExxonMobil's coker unit is operating and coker unit flue gases are burned in the coker CO-boiler, the applicable emission limits are contained in section 3(B)(1) of ExxonMobil's 2000 exhibit.

(ii) *Compliance determining method:* (A) Compliance with the emission limits referenced in 40 CFR 52.1392(f)(4)(i) shall be determined by measuring the SO_2 concentration and flow rate in the coker CO-boiler stack according to the procedures in 40 CFR 52.1392(f)(4)(ii)(B) and (C) and calculating emissions according to the equations in 40 CFR 52.1392(f)(4)(ii)(D).

(B) Beginning on [DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**], ExxonMobil shall at all times operate and maintain a CEMS to measure sulfur dioxide concentrations in the coker CO-boiler stack. This CEMS shall achieve a temporal sampling resolution of at least one concentration measurement per minute, meet the requirements expressed in the definition of ''hourly average'' in 40 CFR 52.1392(c)(12), and meet the CEMS Performance Specifications contained in section 6(C) of ExxonMobil's 1998 exhibit, except that ExxonMobil shall also notify EPA in writing of each annual Relative Accuracy Test Audit a minimum of twenty-five (25) working days prior to actual testing.

(C) Beginning on [DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**], ExxonMobil shall at all times operate and maintain a continuous stack flow rate monitor to measure the stack gas flow rates in the coker CO-boiler stack. This CEMS shall achieve a temporal sampling resolution of at least one flow rate measurement per minute, meet the requirements expressed in the definition of ''hourly average'' in 40 CFR 52.1392(c)(12), and meet the Stack Gas Flow Rate Monitor Performance Specifications of section 6(D) of ExxonMobil's 1998 exhibit, except that ExxonMobil shall also notify EPA in writing of each annual Relative Accuracy Test Audit a minimum of twenty-five (25) working days prior to actual testing.

(D) SO_2 emissions from the coker CO-boiler stack shall be determined in accordance with the equations in sections 2(A)(1), (8), (11)(a) and (16) of ExxonMobil's 1998 exhibit.

(5) *Data reporting requirements:* (i) ExxonMobil shall submit quarterly reports beginning with the first calendar quarter following [DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**]. The quarterly reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to the Air Program Contact at EPA's Montana Operations Office, Federal Building, 10 West 15th Street, Suite 3200, Helena, MT 59626. The quarterly report shall be certified for accuracy in writing by a responsible ExxonMobil official. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written hard copy data summary report.

(ii) The electronic report submitted to the EPA shall be on magnetic or optical media, and such submittal shall follow the reporting format of electronic data being submitted to the MDEQ. The EPA may modify the reporting format delineated in this section, and thereafter ExxonMobil shall follow the revised format. In addition to submitting the electronic quarterly reports to the EPA, ExxonMobil shall also record, organize and archive for at least five years the same data, and upon request by the EPA, ExxonMobil shall provide the EPA with any data archived in accordance with this provision. The electronic report shall contain the following:

(A) Hourly average total sulfur concentrations in ppm in the gas stream to the flare(s);

(B) Hourly average SO_2 concentrations in ppm from the coker CO-boiler stack;

(C) Hourly average volumetric flow rates in SCFH in the gas stream to the flare(s) and in the coker CO-boiler stack;

(D) Hourly average H_2S concentrations in ppm from the refinery fuel gas system;

(E) Hourly average refinery fuel gas combustion units' actual fuel firing rate in SCFH;

(F) Hourly average temperature (in °F) and pressure (in mm or inches of Hg) of the gas stream to the flare(s);

(G) Hourly emissions in pounds per clock hour from the flare(s), coker CO-boiler stack, and refinery fuel gas combustion system;

(H) Daily calibration data for the CEMS required by 40 CFR 52.1392(f)(2)(ii), (f)(3)(ii) and (f)(4)(ii).

(iii) The quarterly written report submitted to the EPA shall contain the following information:

(A) Three hour emissions in pounds per three hour period from the flares, coker CO-boiler stack, and refinery fuel gas combustion system;

(B) Daily emissions in pounds per calendar day from the coker CO-boiler stack and refinery fuel gas combustion system;

(C) The results of the quarterly Cylinder Gas Audits (CGA) or Relative Accuracy Audits (RAA) required by 40 CFR part 60, Appendix F, and the annual Relative Accuracy Test Audit (RATA) for the CEMS required by 40 CFR 52.1392(f)(2)(ii) (total sulfur analyzer(s) only), (f)(3)(ii) and (f)(4)(ii);

(D) For all periods of flare volumetric flow rate monitoring system or concentration analyzer system downtime, coker CO-boiler stack CEMS downtime, or refinery fuel gas combustion system CEMS downtime, the written report shall identify:

(*1*) Dates and times of downtime;

(*2*) Reasons for downtime; and

(*3*) Corrective actions taken to mitigate downtime;

(E) For each three hour period and calendar day in which the flare emission limits, the coker CO-boiler stack emission limits, or the fuel gas combustion system emission limits are exceeded, the written report shall identify:

(*1*) The date, start time, and end time of the excess emissions;

(*2*) Total hours of operation with excess emissions, the hourly emissions, the three hour emissions, and the daily emissions;

(*3*) All information regarding reasons for operating with excess emissions; and

(*4*) Corrective actions taken to mitigate excess emissions.

(F) For all periods that the range of the volumetric flare flow rate monitor(s) is (are) exceeded, the quarterly written report shall identify:

(*1*) Date and time when the range of the flare volumetric flow monitor(s) is (are) exceeded and

(*2*) The reliable estimation parameters used to determine flow in the gas stream to the flare and how the estimation parameters were derived.

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

(g) *Montana Sulphur & Chemical Company (MSCC) emission limits and compliance determining methods:* (1) *Introduction:* The provisions for MSCC cover the following units:

(i) The flares, which consist of the 80 foot west flare, 125 foot east flare, and 100-meter flare.

(ii) The SRU 100-meter stack.

(iii) The auxiliary vent stacks which consist of the vent stacks associated with the Railroad Boiler, the H–1 Unit, the H1-A unit, the H1–1 unit and the H1–2 unit.

(iv) The SRU 30-meter stack. The units that can exhaust through the SRU 30-meter stack are identified in section 3(A)(2)(d) and (e) of MSCC's 1998 exhibit.

(2) *Flare requirements:* (i) *Emission limit:* Total combined emissions of SO_2 from the 80 foot west flare, 125 foot east flare and 100-meter flare shall not exceed 150.0 pounds per three hour period.

(ii) *Compliance determining method:* Compliance with the emission limit in 40 CFR 52.1392(g)(2)(i) shall be determined in accordance with 40 CFR 52.1392(h). In the event MSCC cannot monitor all three flares from a single location, MSCC shall establish multiple monitoring locations.

(3) *SRU 100-meter stack requirements:* (i) *Emission limits:* Emissions of SO_2 from the SRU 100-meter stack shall not exceed:

(A) 3,003.1 pounds per three hour period,

(B) 24,025.0 pounds per calendar day, and

(C) 9,088,000 pounds per calendar year.

(ii) *Compliance determining method.* (A) Compliance with the emission limits contained in 40 CFR 52.1392(g)(3)(i) shall be determined by the CEMS and emission testing methods required by sections 6(B)(1) and (2) and section 5, respectively, of MSCC's 1998 exhibit.

(B) MSCC shall notify EPA in writing of each annual source test a minimum of 25 working days prior to actual testing.

(C) The CEMS referenced in 40 CFR 52.1392(g)(3)(ii)(A) shall achieve a temporal sampling resolution of at least one concentration and flow rate measurement per minute, meet the requirements expressed in the definition of ''hourly average'' in 40 CFR 52.1392(c)(12), and meet the CEM Performance Specifications in sections 6(C) and (D) of MSCC's 1998 exhibit, except that MSCC shall also notify EPA in writing of each annual Relative Accuracy Test Audit at least twenty five (25) working days prior to actual testing.

(4) *Auxiliary vent stacks:* (i) *Emission limits:* (A) Total combined emissions of SO_2 from the auxiliary vent stacks shall not exceed 12.0 pounds per three hour period,

(B) Total combined emissions of SO_2 from the auxiliary vent stacks shall not exceed 96.0 pounds per calendar day,

(C) Total combined emissions of SO_2 from the auxiliary vent stacks shall not exceed 35,040 pounds per calendar year, and

(D) The H_2S concentration in the fuel gas burned in the Railroad Boiler, the H–1 Unit, the H1–A unit, the H1–1 unit, and the H1–2 unit while any of these units is exhausting to the auxiliary vent stacks shall not exceed 100 ppm per three hour period.

(ii) C*ompliance determining method:* (A) Compliance with the emission limits in 40 CFR 52.1392(g)(4)(i) shall be determined by measuring the H_2S concentration of the fuel burned in the Railroad Boiler, the H–1 Unit, the H1–A unit, the H1–1 unit, and the H1–2 unit (when fuel other than natural gas is burned in one or more of these units) according to the procedures in 40 CFR 52.1392(g)(4)(ii)(C).

(B) Beginning [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**], MSCC shall maintain logs of

(*1*) The dates and time periods that emissions are exhausted through the auxiliary vent stacks;

(*2*) The heaters and boilers that are exhausting to the auxiliary vent stacks during such time periods; and

(*3*) The type of fuel burned in the heaters and boilers during such time periods.

(C) Beginning [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**], MSCC shall measure the H_2S content of the fuel burned when fuel other than natural gas is burned in a heater or boiler that is exhausting to an auxiliary vent stack. MSCC shall begin measuring the H_2S content of the fuel at the fuel header within one hour from when a heater or boiler begins exhausting to an auxiliary vent stack and on a once-per-three-hour period frequency until no heater or boiler is exhausting to an auxiliary vent stack. To determine the H_2S content of the fuel burned, MSCC shall use a portable H_2S monitor with a range of 0—500 ppm of H_2S and an accuracy of (2% of 500 ppm. H_2S concentrations shall be measured on an actual wet basis in ppm.

(5) *SRU 30-meter stack:* (i) *Emission limits:* (A) Emissions of SO_2 from the SRU 30-meter stack shall not exceed 12.0 pounds per three hour period,

(B) Emissions of SO_2 from the SRU 30-meter stack shall not exceed 96.0 pounds per calendar day,

(C) Emissions of SO_2 from the SRU 30-meter stack shall not exceed 35,040 pounds per calendar year, and

(D) The H_2S concentration in the fuel gas burned in the heaters and boilers identified in 40 CFR 52.1392(g)(1)(iv) while any of these units is exhausting to the SRU 30-meter stack shall not exceed 100 ppm per three hour period.

(ii) *Compliance determining method:* (A) Compliance with the emission limits in 40 CFR 52.1392(g)(5)(i) shall be determined by measuring the H_2S concentration of the fuel burned in the heaters and boilers identified in 40 CFR 52.1392(g)(1)(iv) (when fuel other than natural gas is burned in one or more of these heaters or boilers) according to the procedures in 40 CFR 52.1392(g)(5)(ii)(C).

(B) Beginning [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**], MSCC shall maintain logs of

(*1*) The dates and time periods that emissions are exhausted through the SRU 30-meter stack;

(*2*) The heaters and boilers that are exhausting to the SRU 30-meter stack during such time periods; and

(*3*) The type of fuel burned in the heaters and boilers during such time periods.

(C) Beginning [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**], MSCC shall measure the H_2S content of the fuel burned when fuel other than natural gas is burned in a heater or boiler that is exhausting to the SRU 30-meter stack. MSCC shall begin measuring the H_2S content of the fuel at the fuel header within one hour from when any heater or boiler begins exhausting to the SRU 30-meter stack and on a once-per-three-hour period frequency until no heater or boiler is exhausting to the SRU 30-meter stack. To determine the H_2S content of the fuel burned, MSCC shall use a portable H_2S monitor with a range of 0—500 ppm of H_2S and an accuracy of +/-2% of 500 ppm. H_2S concentrations shall be measured on an actual wet basis in ppm.

(6) *Data reporting requirements:* (i) MSCC shall submit quarterly reports beginning with the first calendar quarter following [DATE 30 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**]. The quarterly reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to Air Program Contact at EPA's Montana Operations Office, Federal Building, 10 West 15th Street, Suite 3200, Helena, MT 59626. The quarterly report shall be certified for accuracy in writing by a responsible MSCC official. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written hard copy data summary report.

(ii) The electronic report submitted to the EPA shall be on magnetic or optical media, and such submittal shall follow the reporting format of electronic data being submitted to the MDEQ. The EPA may modify the reporting format delineated in this section, and thereafter, MSCC shall follow the revised format. In addition to submitting the electronic quarterly reports to the EPA, MSCC shall also record, organize and archive for at least five years the same data, and upon request by the EPA, MSCC shall provide the EPA with any data archived in accordance with this provision. The electronic report shall contain the following:

(A) Hourly average total sulfur concentrations in ppm, in the gas stream to the flare(s);

(B) Hourly average SO_2 concentrations in ppm from the SRU 100-meter stack.

(C) Hourly average volumetric flow rates in SCFH in the gas stream to the flare(s) and in the SRU 100-meter stack;

(D) Hourly average temperature (in °F) and pressure (in mm or inches of Hg) in the gas stream to the flare(s);

(E) Hourly emissions in pounds per clock hour from the flare(s) and SRU 100-meter stack;

(F) Daily calibration data for flare CEMS, and the SRU 100-meter stack CEMS;

(iii) The quarterly written report submitted to the EPA shall contain the following information:

(A) Three hour emissions in pounds per three hour period from the flares and SRU 100-meter stack, and three hour H_2S concentrations in the fuel gas burned in the heaters and boilers identified in 40 CFR 52.1392(g)(1)(iii) and (iv) while any of these units is exhausting to the SRU 30-meter stack or auxiliary vent stacks and burning fuel other than natural gas;

(B) Daily emissions in pounds per calendar day from the SRU 100-meter stack;

(C) Annual emissions of SO_2 in pounds per calendar year from the SRU 100-meter stack;

(D) The results of the quarterly Cylinder Gas Audits (CGA) or Relative Accuracy Audits (RAA) required by 40 CFR part 60, Appendix F, the annual Relative Accuracy Test Audit (RATA) for total sulfur analyzer(s) and for the SRU 100-meter stack CEMS;

(E) For all periods of flare volumetric flow rate monitoring system or concentration analyzer system downtime, SRU 100-meter CEMS downtime, or failure to obtain an H_2S concentration sample as required by 40 CFR 52.1392(g)(4)(ii)(C) and (g)(5)(ii)(C), the written report shall identify:

(*1*) Dates and times of downtime or failure;

(*2*) Reasons for downtime or failure; and

(*3*) Corrective actions taken to mitigate downtime or failure;

(F) For each three hour period and calendar day in which the flare emission limit, the SRU 100-meter stack emission limits, the SRU 30-meter stack emission limits, or auxiliary vent stack emission limits are exceeded, the written report shall identify:

(*1*) The date, start time, and end time of the excess emissions;

(*2*) Total hours of operation with excess emissions, the hourly emissions, the three hour emissions, and the daily emissions;

(*3*) All information regarding reasons for operating with excess emissions; and

(*4*) Corrective actions taken to mitigate excess emissions.

(G) For all periods that the range of the volumetric flare flow rate monitor(s) is (are) exceeded, the quarterly written report shall identify:

(*1*) Date and time when the range of the flare volumetric flow monitor(s) is (are) exceeded and

(*2*) The reliable estimation parameters used to determine flow in the gas stream to the flare and how the estimation parameters were derived.

(H) Identification of dates:

(*1*) The dates and time periods that emissions are exhausted through the auxiliary vent stacks or the 30-meter stack;

(*2*) The heaters and boilers that are exhausting to the auxiliary vent stacks or 30-meter stack during such time periods; and

(*3*) The type of fuel burned in the heaters and boilers during such time periods.

(I) When no excess emissions have occurred, the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, or all H_2S concentration samples for the heaters and boilers have been taken as required, such information shall be stated in the report.

(h) *Flare compliance determining method:*

(1) Compliance with the emission limits in 40 CFR 52.1392(d)(2)(i), (e)(2)(i), (f)(2)(i) and (g)(2)(i) shall be determined by measuring the total sulfur concentration and volumetric flow rate of the gas stream to the flare(s) (corrected to 1 atmosphere pressure and 68 °F) and using the methods contained in the flare monitoring plan required by 40 CFR 52.1392(h)(5). Volumetric gas stream flow rate to the flare(s) shall be determined in accordance with the requirements in 40 CFR 52.1392(h)(2) and the total sulfur concentration of the gas stream to the flare(s) shall be determined in accordance with 40 CFR 52.1392(h)(3).

(2) *Flare flow monitoring:* (i) Within 180 days after receiving EPA approval of the flare monitoring plan required by 40 CFR 52.1392(h)(5), each facility named in 40 CFR 52.1392(a) shall install and calibrate, and thereafter calibrate, maintain and operate, a continuous flow monitoring system capable of measuring the total volumetric flow of the gas stream to the flare(s) over the full range of operation. The flow monitoring system may require one or more flow monitoring devices or flow measurements at one or more locations if one monitor cannot measure the total volumetric flow to each flare.

(ii) Volumetric flow monitors meeting the proposed volumetric flow monitoring specifications below should be able to measure the majority of volumetric flow in the gas streams to the flare. However, in rare events (*e.g.*, such as upset conditions) it is possible for the flow to the flare to exceed the range of the monitor. In such cases, reliable flow estimation parameters may be used to determine the volumetric flow rate to the flare, which shall then be used to calculate SO_2 emissions. In quarterly reports, sources shall indicate when reliable estimation parameters are used and how such parameters were derived.

(iii) The flare gas stream volumetric flow rate shall be measured on an actual wet basis in SCFH. The minimum detectable velocity of the flow monitoring device(s) shall be 0.1 feet per second (fps). The flow monitoring device(s) shall continuously measure the range of flow rates corresponding to velocities from 0.5 to 275 fps and have a manufacturer's specified accuracy of ±5% over the range of 1 to 275 fps. The volumetric flow monitor(s) shall feature automated daily calibrations at low and high ranges. The volumetric flow monitors shall be calibrated annually according to manufacturer's specifications.

(iv) For correcting flow rate to standard conditions (defined as 68 °F and 760 mm, or 29.92 inches, of Hg)), temperature and pressure shall be monitored continuously. The temperature and pressure shall be monitored in the same location as the flow monitoring device(s) and shall be calibrated to meet accuracy specifications as follows: temperature shall be calibrated annually to within ±2.0% at absolute temperature and the pressure monitor shall be calibrated annually to within ±5.0 mmHg.

(v) The flow monitoring device(s) shall be initially calibrated, prior to installation, to demonstrate accuracy to within 5.0% at flow rates equivalent to 30%, 60% and 90% of monitor full scale.

(vi) Each flow monitoring device shall achieve a temporal sampling resolution of at least one flow rate measurement per minute, meet the requirements expressed in the definition of hourly average in 40 CFR 52.1392(c)(12), and be installed in a manner and at a location that will allow for accurate measurements of the total volume of the gas stream going to each flare.

(3) *Flare concentration monitoring:*

(i) Within 180 days after receiving EPA approval of the flare monitoring plan required by 40 CFR 52.1392(h)(5), each facility named in 40 CFR 52.1392(a) shall install and calibrate, and thereafter calibrate, maintain and operate, a continuous total sulfur concentration monitoring system capable of measuring the total sulfur concentration of the gas stream to each flare. Continuous monitoring shall occur at a location(s) that is (are) representative of the gas combusted in the flare and be capable of measuring the expected range of total sulfur in the gas stream to the flare. The concentration monitoring system may require one or more concentration monitoring devices or concentration measurements at one or more locations if one monitor cannot measure the total sulfur concentration to each flare.

(ii) The total sulfur analyzer(s) shall achieve a temporal sampling resolution of at least one concentration measurement per fifteen minutes, meet the requirements expressed in the definition of ''hourly average'' in 40 CFR 52.1392(c)(12), be installed, certified (on a concentration basis), and operated in accordance with 40 CFR part 60, Appendix B, Performance Specification 5, and be subject to and meet the quality assurance and quality control requirements (on a concentration basis) of 40 CFR part 60, Appendix F.

(iii) Each affected facility named in 40 CFR 52.1392(a) shall notify the Air Program Contact at EPA's Montana Operations Office, Federal Building, 10 West 15th Street, Suite 3200, Helena, MT 59626, in writing of each Relative Accuracy Test Audit a minimum of twenty-five (25) working days prior to the actual testing.

(4) *Calculation of SO_2 emissions from flares.* Methods for calculating hourly and three hour SO_2 emissions from flares shall be submitted with the flare monitoring plan discussed in 40 CFR 52.1392(h)(5).

(5) By [DATE 180 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **Federal Register**], each facility named in 40 CFR 52.1392(a) shall submit a flare monitoring plan. Each flare monitoring plan shall include, at a minimum, the following:

(i) A facility plot plan showing the location of each flare in relation to the general plant layout;

(ii) Information regarding pilot and purge gas for each flare; what is used for pilot and purge gas and how the concentration and volumetric flow rate monitors are analyzing the pilot and purge gases.

(iii) Drawing(s) with dimensions, preferably to scale, and an as built process flow diagram of the flare(s) identifying major components, such as flare header, flare stack, flare tip(s) or burner(s), purge gas system, pilot gas system, ignition system, assist system, water seal, knockout drum and molecular seal.

(iv) A representative flow diagram showing the interconnections of the flare system(s) with vapor recovery system(s), process units and other equipment as applicable.

(v) A complete description of the assist system process control, flame detection system and pilot ignition system.

(vi) A complete description of the gas flaring process for an integrated gas flaring system that describes the method of operation of the flares.

(vii) A complete description of the vapor recovery system(s) which have interconnection to a flare, such as compressor description(s), design capacities of each compressor and the vapor recovery system, and the method currently used to determine and record the amount of vapors recovered.

(viii) Drawing(s) with dimensions, preferably to scale, showing the following information for proposed flare gas stream monitoring system:

(A) Sampling locations; and

(B) Flow monitoring device and total sulfur analyzer locations and the methods used to determine the locations.

(ix) A detailed description of manufacturer's specifications, including but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance, a quality assurance procedure and any other relevant specifications and information referenced in 40 CFR 52.1392(h)(2) and (3) for all existing and proposed flow monitoring devices and total sulfur analyzers.

(x) A complete description of the proposed data recording, collection and management and any other relevant specifications and information referenced in 40 CFR 52.1392(h)(2) and (3) for each flare monitoring system.

(xi) A complete description of the proposed method to determine, monitor and record total volume and total sulfur concentration of gases combusted in the flare.

(xii) A complete description of the method and equations used to calculate the amount of total sulfur, including all conversion factors. The total sulfur concentrations will be used in the methods referenced in 40 CFR 52.1392(h)(4) to determine compliance with the three-hour emission limit.

(xiii) A schedule for the installation and operation of each flare monitoring system consistent with the deadline in 40 CFR 52.1392(h)(2).

(xiv) A complete description of the methods to be used to estimate flare emissions when either the flow monitoring device or total sulfur analyzer are not working or the operating range of the monitor or analyzer is exceeded.

(xv) A complete description of the methods to be used for calculating, and hourly and three-hour SO_2 emission from flares.

(6) Thirty days prior to installing the continuous monitors required by 40 CFR 52.1392(h)(2) and (3), each facility named in 40 CFR 52.1392(a) shall submit for EPA review a quality assurance/quality control (QA/QC) plan for each monitor being installed.

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FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[DA 06–1308; MB Docket No. 04–318; RM–11040]

Radio Broadcasting Services; Culebra and Vieques, Puerto Rico

AGENCY: Federal Communications Commission.

ACTION: Proposed rule; denial.

SUMMARY: We deny the petition for rule making filed by Western New Life, Inc., proposing the substitution of Channel 291A for Channel 254A at Culebra, Puerto Rico. To accommodate the substitution, Petitioner also proposed the deletion of vacant Channel 291B at Vieques, Puerto Rico. We find that neither the deletion of Channel 291B, nor the alternative downgrade and substitution of Channel 254A for Channel 291B at Vieques, is in the public interest. Specifically, expressions of interest have been filed to retain the Vieques vacant channel as a Class B allotment.