**40 CFR 60 Subpart J - Rule Interpretation Memos**

- ! The equation for coke burn-off rate given in 40 Code of Federal Regulations Part 60 (40 CFR 60) is incorrect.- RETIRED [November 15, 1999]
- ! Applicability of 40 CFR 60, Subpart J to various refinery operations. [September 22, 2000]
- ! Typographical error in 60.106(e)(2) [December 22, 2000]

Last Modified: December 22, 2000

**Retired as a result of amendments to 40 CFR Part 60, Subpart J adopted on 10/17/2000 (Federal Register, Volume 65, pg. 61744**

Last Modified: October 17, 2000

**DATED: DECEMBER 2, 1999; SIGNED: KEN GIGLIELLO for**

Phillip E. Guillemette
Director of Environmental Affairs
Koch Refining Company LP
P.O. Box 64596
Saint Paul, Minnesota 55164-0596

Dear Mr. Guillemette:

This is in response to your August 14, 1998, and January 6, 1999, letters to Administrator Browner. Koch Refining Company LP (Koch) seeks clarification from the Environmental Protection Agency (EPA) regarding the applicability of New Source Performance Standard Subpart J (NSPS Subpart J) to: fuel gas combustion devices (FGCDs) and fuel gases; "process upset" conditions; and to certain identified gas streams at its Rosemount, Minnesota refinery. Although you requested that EPA review and revise NSPS Subpart J in your August 14, 1998, letter, it is our current understanding that you are not requesting that NSPS Subpart J be reviewed/revised as part of a response to your letters.

You write that NSPS Subpart J is, in part, intended to reduce sulfur emissions from gases generated as a byproduct of the refining process that are used as fuel in a refinery's heaters and boilers. To accomplish this, NSPS Subpart J imposes monitoring requirements and limits for certain fuel gas streams that are combusted in refinery FGCDs. You assert that "fuel gas" and "FGCD" are vaguely defined, and it is often unclear as to what types of units and streams are covered under the standard. We disagree with your characterization that "fuel gas" and "FGCD" are not clearly defined. The definitions are purposefully broad, and the exemptions are specific. We also disagree with your characterizations that the rule is limited to only refinery generated gases burned as fuel in refinery process heaters and boilers. The rule clearly includes routine combustion of refinery gases in flares and other waste gas disposal devices.

In your letter, you develop a position on exemptions from NSPS Subpart J based on the commendable use of a flare gas recovery system. You describe your refinery flare gas recovery system, and state that:

> . . . [a]s designed, the flare gas recovery system has sufficient capacity to recover gases that are routed to the system under normal operating conditions . . . . Under process upset conditions, the flare gas recovery system's capacity may be exceeded and excess gases are routed to the flare for combustion . . . .

Because you believe that your refinery gases are routed to the flare only as a result of process upsets, you believe that the flaring of those gases are not subject to NSPS Subpart J. We do not agree that all of the events you describe as "process upset conditions" meet the regulatory definition of malfunction or the interpretation of "upset", and, therefore, may not be qualified for exemption from NSPS Subpart J. In addition, we note that any malfunction or upset involving combustion of process upset gas in an NSPS-affected FGCD would still be subject to NSPS Subpart A (General Provisions) §60.11(d) obligations.

Your August 14, 1998, letter focuses on three areas:

- How NSPS Subpart J applies to FGCDs and fuel gases;
- How the process upset gas exemption applies;
- How NSPS Subpart J applies to the 26 miscellaneous gas streams.

Our response addresses those issues in order.

**How NSPS Subpart J Applies to FGCDs and Fuel Gases**

The provisions of NSPS Subpart J are, in part, applicable to affected FGCDs. To control sulfur oxide ($SO_x$) emissions to the atmosphere from affected FGCDs, NSPS Subpart J §60.104(a)(1) limits the amount of hydrogen sulfide ($H_2S$) allowed in the fuel gas burned in those devices. Except for fuel gas released to a flare as a result of relief valve leakage or other emergency malfunctions, you must not burn fuel gas containing greater than 230 mg/dscm of $H_2S$ in any affected FGCD. Additionally, the combustion of a process upset gas in a FGCD is exempt from the $H_2S$ limit. The combustion/flaring of those exempted gases in an NSPS-affected FGCD is still subject to §60.11(d) of the General Provisions as described later.

NSPS Subpart J §60.104(a)(1) applies to gas combustion devices, if the following are true:

1) The gas is a "fuel gas" [§60.101(d)]:

> . . . any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners.

2) The fuel gas is combusted in a "FGCD" [§60.101(g)]:

> . . . any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

3) The FGCD is an "affected FGCD". An affected FGCD is any FGCD for which construction or modification commenced after June 11, 1973. §60.100(b)

Additionally, when determining the applicability of NSPS Subpart J to any particular combination of combustion device and gas stream, the following general concepts apply:

- Unlike the definition of process upset gas, the definition of fuel gas does not require that the gas be generated by a "refinery process unit", it must merely be generated at the refinery;
- There is no general exemption for gas streams with low sulfur content;
- There is no general exemption for low volume or intermittent gas streams;
- A FGCD need not generate a product to be regulated. Flares do not generate products or energy that are recovered for use, but they are clearly FGCDs since they are specifically named in the definition.

Your refinery flares (constructed after June 11, 1973) are affected FGCDs as defined by NSPS Subpart J. When the capacity of your refinery flare gas recovery system is exceeded as the result of normal operations (not malfunctions), NSPS Subpart J for FGCDs applies to those NSPS refinery flares.

For any fuel gas stream subject to NSPS Subpart J, you may petition for alternative monitoring under the General Provisions at §60.13(i). For EPA to approve alternative monitoring, you must submit sufficient information to show that your alternative monitoring plan will yield similar results to the required monitoring under NSPS Subpart J.

**How the Process Upset Gas Exemption Applies**

As mentioned above, §60.104(a)(1) exempts the combustion in a FGCD of process upset gases and exempts the combustion in a flare of fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunction. Not all of the events you describe as "process upset conditions" meet the qualifications for exemption from NSPS Subpart J. Therefore, the 26 gas streams do not receive a blanket exemption from the regulation. Some of the gases generated under Koch's described events are not gases generated as a result of upsets, but are generated as a result of normal operations. Additionally, not all of your process upsets result in flaring.

Process upset gas is defined at §60.101(e) as:

> . . . any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

Malfunction is defined in the General Provisions at §60.2 as:

> . . . any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Upset is not defined in NSPS Subpart J or in the General Provisions. However, in EPA's 1973 Background Information for Proposed New Source Performance Standards for Petroleum Refineries, PB-221 736 (1973 BID), page 25, EPA writes that the proposed standard does not apply to extraordinary situations, such as emergency gas releases. In EPA's 1974 Background Information for New Source Performance Standards for Petroleum Refineries, PB-231 601 (1974 BID), page 20, EPA further explained the statement in the 1973 BID that:

> Because the frequency of process upsets and the volumes of gases which must be disposed of are highly unpredictable, it is not feasible to design or operate a gas treating facility that would prevent sulfur dioxide emissions from flare systems in these situations. A facility designed to remove hydrogen sulfide from all process upset gases prior to combustion would have to be designed to handle the immediate release of gases from all process units if each unit experienced the worst possible upset or malfunction at the same time. The cost of such a large gas treatment facility would impose a severe and unreasonable economic burden upon a refinery.

From the language in the 1974 BID, it is clear that a facility does not have to be designed to treat and dispose of gases produced in a worst case scenario at a facility. However, it is clear that more frequent and predicable process events (which Koch would describe as "upsets", but which do not meet the interpretation for upsets) are subject to the standard, and that it is not unreasonable for the facility to have sufficient capacity to handle these routine process events.

In a similar issue, EPA successfully argued in a case before an Administrative Law Judge (ALJ), that the term "system breakdown" (which is used in 40 CFR §60.13(e), but is undefined) was akin to a malfunction as defined in the General Provisions at §60.2. In the March 9, 1995, decision (see Enclosure 1), the ALJ wrote that:

> While the actual words "system breakdown" do not appear here [in the definition of malfunction], this definition incorporates analogous phrases . . . . Thus using the definition of malfunction as a guide, a system breakdown would constitute something sudden and unforeseen . . . . Accordingly, it is found that a system breakdown requires there to be an occurrence which is unforseen, sudden and unavoidable.

The same logic that went into the ALJ's decision applies here; the exemption was intended for infrequent and unpredictable events, thus, "upset" is analogous to malfunction.

Therefore, the malfunction/upset exemption under NSPS Subpart J applies only to extraordinary, infrequent, and not reasonably preventable upsets. Additionally, the malfunction/upset cannot be the result of poor maintenance or careless operations. Once you determine the cause of a malfunction/upset, you should work to correct the root cause in order to prevent it from occurring again. Each time that is done, malfunctions/upsets should become less frequent.

Process upset gases exempted under NSPS Subpart J are still required to comply with the good air pollution control practices as required under §60.11(d).

> At all times, including periods of start-up, shut-down, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions . . . .

**How NSPS Subpart J Applies to the 26 Specific Gas Streams**

(Unless stated otherwise, it is assumed that all of the following gas streams are generated "at" the refinery and are combusted. The general concepts identified on page 2 of this letter should be incorporated into EPA's responses when those concepts address the position(s) presented by Koch for a particular gas stream.)

**A. Commercial Grade Natural Gas**

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

Refinery generated, commercial grade, natural gas is subject to NSPS Subpart J if it is combusted in an affected FGCD.

Refinery generated, commercial grade, natural gas meets the definition of fuel gas.

Note: Commercial grade natural gas purchased from an outside source is not generated "at" the refinery and is not, itself, a fuel gas. EPA has previously determined that an NSPS affected gas combustion device is not required to have an installed $SO_2$ or $H_2S$ CEM if that device has been confirmed to not burn refinery fuel gas, in any mixture and at any time (e.g., To be exempt from NSPS Subpart J, a combustion device must be fired only with purchased gas from a dedicated line, and must be isolated from the refinery's fuel gas system). See the December 4, 1991, memorandum from John B. Rasnic. (Enclosure 2)

**B. Hydrogen Plant PSA Purge Gas**

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

The combustion of Hydrogen Plant PSA Purge gas in the #2 Hydrogen Plant process heater is subject to NSPS Subpart J.

1) Hydrogen Plant PSA Purge Gas meets the definition of fuel gas.

2) The Hydrogen purge gas is burned in the #2 Hydrogen Plant process heater. The #2 Hydrogen Plant process heater meets the definition of FGCD.

3) The #2 Hydrogen Plant process heater is an "affected" FGCD.

**C. Commercial Grade Propane (LPG)**

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

Refinery generated, commercial grade, propane gas is subject to NSPS Subpart J if it is combusted in an affected FGCD.

Refinery generated, commercial grade, propane gas meets the definition of fuel gas.

Note: Commercial grade propane gas purchased from an outside source is not generated "at" the refinery and is not, itself, a fuel gas. To be exempt from NSPS Subpart J, a combustion device must be fired only with purchased gas from a dedicated line, and must be isolated from the refinery's fuel gas system.

## D. Commercial Grade Hydrogen

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

Refinery generated, commercial grade, hydrogen is subject to NSPS Subpart J if it is combusted in an affected FGCD.

Refinery generated, commercial grade, hydrogen meets the definition of fuel gas.

Commercial grade hydrogen purchased from an outside source is not generated "at" the refinery and is not, itself, a fuel gas. To be exempt from NSPS Subpart J, a combustion device must be fired only with purchased gas from a dedicated line, and must be isolated from the refinery's fuel gas system.

## E. Delayed Coker Blowdown

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's position:

Any coker blowdown gas generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J.

1) Vapor from the delayed coker blowdown process meets the definition of fuel gas.

Coker blowdown vapor is generated as a normal part of operations, and not the result of a process upset or malfunction. Nor is it exempt because it is generated during a "shutdown" since the coking process has not shutdown. Rather, the stream to the cokers is merely shifted from one coking drum to another to maintain continuous operation of the coker unit.

2) The hydrocarbon vapors from the blowdown process are directed to your flare gas recovery system. When the refinery flare gas recovery system's capacity is exceeded, the excess gas flared.

3) As described earlier, the refinery flares are affected FGCDs.

## F. Rail Loading Rack Thermal Oxidizer

Koch's Position:

NSPS Subpart J is inapplicable because the thermal oxidizer is not a "FGCD" subject to Subpart J, and vapors routed to the thermal oxidizer are low in sulfur and are not a "fuel gas" generated by a refinery process.

EPA's response:

Vapor from loading rack operations is subject to NSPS Subpart J if it is combusted in an affected FGCD.

1) Vapors from loading racks located at the refinery meet the definition of fuel gas.

2) Although the oxidizer may be added as a control device under the refinery MACT, it still meets the definition of FGCD under NSPS Subpart J and is subject to NSPS Subpart J. The refinery MACT (40 CFR Part 63 Subpart CC) is designed to limit the

release of hazardous air pollutants (HAPs) and not $SO_x$ from petroleum refineries. Combustion of those HAPs is not the only control option available for compliance with the refinery MACT. Other compliance alternatives under the refinery MACT that do not involve combustion will not trigger the NSPS Subpart J requirements.

## G. Soil Vapor Extraction Thermal Oxidizer

Koch's Position:

NSPS Subpart J is inapplicable to this stream because vapors recovered from soil remediation are not a "fuel gas", and the thermal oxidizer is not a "FGCD".

EPA's response:

Extracted soil vapor is subject to NSPS Subpart J if it is combusted in an affected FGCD.

1) Vapors extracted from the soil within the refinery meet the definition of fuel gas.

2) The thermal oxidizer is a FGCD since it combusts a fuel gas.

## H. Wastewater Treatment Plant Thermal Oxidizer

Koch's Position:

NSPS Subpart J is inapplicable because vapors from the wastewater treatment plant are not a "fuel gas", and the thermal oxidizer is not a "FGCD".

EPA's response:

Vapor from the refinery's WWTP is subject to NSPS Subpart J if it is combusted in an affected FGCD.

1) The refinery is operating a wastewater treatment plant (WWTP) at the refinery. The vapors collected from the WWTP meet the definition of fuel gas. Other regulations (i.e., NSPS QQQ) that may cover vapors from the WWTP do not specifically exempt the WWTP vapors from applicability under NSPS Subpart J.

2) Although a thermal oxidizer may be a control device for other regulations (i.e., NSPS QQQ), it meets the definition of FGCD for NSPS Subpart J.

Note: Your claim that EPA's approval of the State Implementation Plan (SIP) order for the Dakota County/Pine Bend Area of Air Quality Control Region 131 is evidence of EPA's determination that NSPS Subpart J is inapplicable to this gas stream is not correct. In approving the SIP order, the gas stream was not characterized as being combusted in an NSPS Subpart J applicable fuel gas combustion device, and EPA was not asked to make a determination of the applicability of NSPS Subpart J to any gas streams or affected fuel gas combustion devices. It merely represents EPA's approval of the State's requirements. Additionally, EPA included language in Amendment Three to the Findings and Order by Stipulation in paragraphs D and H indicating that the order does not relieve Koch of the obligation to comply with all applicable laws and regulations, and that those requirements may be more stringent. The relevant pages of Amendment Three are included as Enclosure 3.

**I. Merox Off-Gas (34-H-3 Thermal Oxidizer)**

Koch's Position:

NSPS Subpart J is inapplicable to this stream because the thermal oxidizer was constructed prior to June 11, 1973, and has not been modified or reconstructed.

EPA's response:

Any fuel gas combusted in the 34-H-3 thermal oxidizer is not subject to NSPS Subpart J §60.104(a)(1) as long as the thermal oxidizer is not modified or reconstructed.

1) Merox caustic regenerator vent gas, vapors from spent caustic storage tanks, sour water flash drums, and fresh amine storage tanks meet the definition of fuel gas.

2) The 34-H-3 thermal oxidizer meets the definition of FGCD.

3) Based on your statement that the 34-H-3 thermal oxidizer was constructed before June 11, 1973, it is not an "affected" FGCD unless it has since been modified or reconstructed.

**J. Caustic Neutralizer Off-Gas**

Koch's Position:

NSPS Subpart J is inapplicable to the stream because the CO boiler was constructed prior to June 11, 1973 and has not been modified or reconstructed.

EPA's response:

Any gas combusted in the CO boiler is not subject to NSPS Subpart J §60.104(a)(1) as long as the CO boiler is not modified or reconstructed.

1) The off-gas from the spent caustic neutralizers meets the definition of fuel gas.

2) The spent caustic off-gas is routed to the CO boiler. The CO boiler meets the definition of FGCD.

3) Based on your statement that the CO boiler was constructed before June 11, 1973, and has not been modified or reconstructed, it is not an "affected" FGCD.

**K. Reformer Catalyst Regeneration Streams**

Koch's Position:

NSPS Subpart J is inapplicable because these streams are inherently low in sulfur, and they fall under the Subpart J exemption for process upset gas.

EPA's response:

Any regeneration gas generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J. Additionally, lock hopper gas that is not directed to the refinery flare gas recovery system but is directed to a refinery heater is subject to NSPS Subpart J if the refinery heater is an affected FGCD.

1) Reformer catalyst regeneration gas streams meet the definition of fuel gas.

Gas produced during the routine switching of reformer reactors, as described by Koch, does not meet the process upset gas definition because the gas is generated as a normal part of operations. Nor is it exempt because it is generated during a "shutdown" since the reformer process has not shutdown. Rather, operations merely shift from one reactor to another so that spent catalyst may be regenerated while the reformer unit continues operation.

2) Reformer catalyst regeneration gas produced during the switching process is directed to your flare gas recovery system or, for final lock hopper depressurization, to a refinery heater. When the refinery flare gas recovery system's capacity is exceeded, the excess gas flared.

3) As described earlier, the refinery flares are affected FGCDs.

**L. Vacuum Unit Off-Gas**

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

According to your description, equipment leaks may allow air to enter the process creating a potential for the formation of combustible mixtures. Under normal operation, vacuum gases are routed to the fuel gas system. The only time vacuum unit off-gas potentially may be combusted in a fuel gas combustion device is when there has been a process upset as defined under NSPS Subpart J §60.101(e).

EPA's response:

Vacuum unit off-gas that meets the definition of process upset gas is subject to NSPS Subpart A §60.11(d).

1) Vacuum unit off-gas meets the definition of fuel gas.

2) Any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction is a process upset gas.

3) Vacuum unit off-gas generated during periods of a malfunction of the vacuum distillation column meets the definition of process upset gas.

Additionally, in our August 10, 1999, meeting, we discussed the effect of shut-downs of Koch's low pressure off-gas recovery compressor and flare gas recovery compressor. Koch has a compressor system designed to recover discharges (off-gas) from the vacuum generating equipment. The recovered off-gas is normally routed to the refinery fuel gas recovery system for $H_2S$ removal. In the event of an off-gas recovery compressor shut-down, the off-gas is routed to the refinery flare gas recovery system and is not sent to the flare. Only when both compressors malfunction would the gas be routed to the flare. If both compressors are down at the same time due to malfunctions as defined under NSPS Subpart A §60.2, then the vacuum unit off-gas would meet the exemption under NSPS Subpart J §104(a)(1) for other emergency malfunctions. Off-gases exempted from the emission requirements under NSPS Subpart J §60.104(a)(1) are still subject to NSPS Subpart A §60.11(d).

**M. Slop Oil Flash Drum**

Koch's Position:

> NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

> Any vapor from the slop oil process which is generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J.
>
> 1) In general, vapors generated by the slop oil process at Koch meet the definition of fuel gas. Sending off-specification products to the slop oil system does not qualify as a process upset.
>
> 2) When the refinery's flare gas recovery's system is exceeded, excess gas is sent to the refinery's flares. Process upsets/malfunctions are not the only reasons that Koch's flare gas recovery system's capacity may be exceeded. The refinery's flare gas recovery system may be exceeded as a result of normal operations (e.g., delayed coker blowdown).
>
> 3) As described earlier, the refinery flares are affected FGCDs.

**N. Alkylation Unit Acid Neutralization Pit Off-Gas**

Koch's Position:

> NSPS Subpart J is inapplicable to this stream because the sulfuric acid alkylation units is not a "FGCD", and this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

> If the off-gas from the alkylation unit acid neutralization is not combusted, NSPS Subpart J is not applicable. Only gases generated and combusted at the refinery (including purchased gas that is mixed with fuel gas) meet the definition of fuel gas.

**O. Flare Pilot and Purge**

Koch's Position:

> NSPS Subpart J is inapplicable because pilot and purge gas is not a "fuel gas", and this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

As identified in your letter, EPA issued a determination (March 22, 1977) regarding refinery pilot lights. We reaffirm our earlier position that NSPS Subpart J is inapplicable to refinery pilot lights. Since a pilot light ensures that a combustion device will operate properly, the pilot light, by itself, is not the combustion device.

**P. Miscellaneous Process Streams Routed to Flare Gas Recovery System**

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

Any vapors from the refinery's miscellaneous process streams generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J.

1) Vapors from miscellaneous process streams meet the definition of fuel gas because they are not specifically exempted from the definition of fuel gas.

2) When the refinery's flare gas recovery system is exceeded, excess gas is sent to the refinery's flares. Process upsets/malfunctions are not the only reasons that Koch's flare gas recovery system's capacity may be exceeded. The refinery's flare gas recovery system may be exceeded as a result of normal operations.

3) As described earlier, the refinery flares are affected FGCDs.

**Q. Butane Storage Tank 517 Thermal Oxidizer**

Koch's Position:

NSPS Subpart J is inapplicable because this stream is not generated by a Refinery process, it is inherently low in sulfur, and it is subject to the Subpart J exemption for process upsets. To date, the thermal oxidizer has never been used.

EPA's response:

Butane vapors generated as a result of a refrigerator system malfunction are not subject to NSPS Subpart J control requirements, but are subject to NSPS Subpart A §60.11(d).

1) Butane vapors meet the definition of fuel gas.

2) If butane vapors are formed as a result of refrigeration system malfunction, the vapors are routed to tank 517 thermal oxidizer.

3) NSPS Subpart J §61.104(a)(1) exempts the combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunction.

**R. FCC Catalyst Regenerator Off-Gas**

Koch's Position:

NSPS Subpart J is inapplicable because this stream is subject to the express exemption for catalytic cracking unit catalyst regenerators.

EPA's response:

FCC catalyst regenerator off-gas does not meet the definition of fuel gas and, therefore, is exempt from NSPS Subpart J §60.104(a)(1).

**S. MEA and MDEA Regenerator Off-Gas**

Koch's Position:

NSPS Subpart J fuel gas requirements are inapplicable because this stream falls under the exemption for facilities that are part of the sulfur production process.

EPA's response:

Sending these streams to the sulfur recovery unit (SRU) does not subject them to the NSPS Subpart J standard for the combustion of a fuel gas in a FGCD.

1) MEA and MDEA regenerator off-gas streams meet the definition of fuel gas.

2) Because these recycled streams are sent to the front of the SRU, and the SRU is a facility in which gases are combusted to produce sulfur or sulfuric acid, these streams are not being combusted in a FGCD.

**T. Sour Water Tank Purge Gas**

Koch's Position:

This stream falls under the Subpart J exemption for sulfur production facilities and has previously been determined by USEPA to be not subject to NSPS Subpart J fuel gas requirements.

EPA's response:

If the standby incinerator was constructed or modified after June 11, 1973, it is an affected FGCD and the combustion of sour water tank purge gas is subject to NSPS Subpart J.

1) Sour water tank purge gas meets the definition of fuel gas.

2) Sour water tanks store process water from various refinery process units. These tanks are not part of the SRU since they are not part of the unit that recovers sulfur from $H_2S$ by a vapor-phase catalytic reaction of $SO_2$ and $H_2S$.

3) At Koch's facility, the sour water tank purge gas is sent to directly to a SRU standby incinerator (affected FGCD) for thermal oxidation without going through the SRU.

Note: Again, you claim that EPA's approval of the State Implementation Plan (SIP) order for the Dakota County/Pine Bend Area of Air Quality Control Region 131 is evidence of EPA's determination that NSPS Subpart J is inapplicable to this gas stream. For the reasons stated in our response to stream H, your belief is not correct.

**U. Sour Water Stripper Overhead Gas**

Koch's Position:

NSPS Subpart J fuel gas requirements are inapplicable because this stream is part of the sulfur production process and falls under the Subpart J exemption for process upset gas.

EPA's response:

Introducing these streams into the SRU does not subject them to NSPS Subpart J requirements applicable to the combustion of a fuel gas in a FGCD.

1) Sour water stripper overhead gas meets the definition of fuel gas.

2) Sour water strippers are not part of the SRU since they are not part of the unit that recovers sulfur from $H_2S$ by a vapor-phase catalytic reaction of $SO_2$ and $H_2S$.

3)  Koch sends the sour water stripper overhead gas to the SRU.  The SRU is not a FGCD because it is a facility in which gases are combusted to produce sulfur or sulfuric acid.

Note:  Koch indicates that this gas may be routed to a FGCD (bypassing the SRU) during periods of start-up, shut-down or malfunction of the SRU.  It maintains that such combustion is not subject to Subpart J's sulfur oxide standard because these gases are exempt process upset gases.

Exemptions from rules of general applicability are to be construed narrowly. Nonetheless, EPA recognizes that there are certain limited circumstances under which normal processes may be bypassed because upset conditions exist in some upstream process unit (e.g., if upstream gas quality will cause a malfunction in a downstream unit, the gas is diverted to a flare instead).

It is the refinery's burden to demonstrate that a malfunction has occurred each time a downstream unit is bypassed (or otherwise demonstrate that its actions are exempt from regulation).  EPA notes that a malfunction must be infrequent, not reasonably preventable and not attributable to poor maintenance or careless operation.  For example, a "malfunction" caused by the same or similar conditions as had occurred previously will lose its exempt character and be subject to all applicable standards and requirements.

Periods of routine or periodic maintenance to downstream units are not malfunctions at either the upstream or the downstream unit.  Gases generated in the upstream units are not then process upset gases, their combustion is subject fully to applicable NSPS Subpart J standards and the bypassing (without proper controls) of a downstream unit that is undergoing routine or periodic maintenance would not be permitted.

If the capacity of the SRU is exceeded due to process upset gases, such gases may be flared (but only to the extent attributable to such upset gas).  Such instances are also subject to §60.11(d).  See discussion above.

## V. Ammonia Acid Gas Flare

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.  The acid gas flare is used only for ammonia acid gas that cannot be processed in the SRU due to start-up, shut-down or malfunction.

EPA's response:

Process upset gases are those gases generated by a refinery process unit during periods of start-up, shut-down, upset or malfunction.  Such gases are subject to 60.11(d).  See discussion above.

1) Ammonia acid gas meets the definition of fuel gas.

2) Combustion of a fuel gas in a flare constructed or modified after June 11, 1973, is subject to Subpart J standards for sulfur oxides, but combustion of process upset gases is exempt from those standards.

Note: Exemptions from rules of general applicability are to be construed narrowly. Nonetheless, EPA recognizes that there are certain limited circumstances under which normal processes may be bypassed because upset conditions exist in some upstream process unit (e.g., if upstream gas quality will cause a malfunction in a downstream unit, the gas is diverted to a flare instead).

It is the refinery's burden to demonstrate that a malfunction has occurred each time a downstream unit is bypassed (or otherwise demonstrate that its actions are exempt from regulation). EPA notes that a malfunction must be infrequent, not reasonably preventable and not attributable to poor maintenance or careless operation. For example, a "malfunction" caused by the same or similar conditions as had occurred previously will lose its exempt character and be subject to all applicable standards and requirements.

Periods of routine or periodic maintenance to downstream units are not malfunctions at either the upstream or the downstream unit. Gases generated in upstream units are not then process upset gases, their combustion is subject fully to applicable NSPS Subpart J standards and the bypassing of a downstream unit that is undergoing routine or periodic maintenance would not be permitted.

Based on information EPA has, numerous episodes of combustion of ammonia acid gas in a flare subject to NSPS Subpart J suggests that there are operation and maintenance problems with those refinery units generating and/or processing that gas.

**W. Sulfur Degassing Off-Gas**

Koch's Position:

This stream falls under the Subpart J exemption for sulfur production facilities and has previously been determined by USEPA to be not subject to Subpart J fuel gas requirements.

EPA's response:

The sulfur degassing off-gas is generated within the SRU, it is subject to the requirements of NSPS Subpart J §60.104(a)(2) and is exempt from §60.104(a)(1). Please note that some other sulfur pit degasification processes would not be considered as integral parts of a Claus sulfur recovery plant, as defined, and consequently, their exhaust gases could be subject to §60.104(a)(1).

It is our understanding that Koch uses the Shell sulfur degasification process. This process involves a vapor phase reaction that converts much of the dissolved H2S into elemental sulfur within the stripping column of the sulfur pit. For purposes of the regulation, this conversion process is equivalent to the Claus process.

It appears, from your May 14, 1999, Generic Tail Gas Treatment Unit (TGTU) Flow Chart, that the sulfur degassing off-gas is generated within the sulfur pit of each SRU and then routed to the emergency bypass incinerator to be combusted. It is combusted along with sour water tank off-gas, fuel gas and any tail gas from the SRU that bypassed the TGTU. That combustion results in an exhaust that is a combination of gases, some subject to §60.104(a)(1) and others to §60.104(a)(2). Accordingly, each stream going to the emergency bypass incinerator must be monitored separately, or the more stringent of the two limits applies (in this case, the FGCD limit). Streams subject to the same standards may be combined and only the combined stream need then be monitored.

Note: Again, you claim that EPA's approval of the State Implementation Plan (SIP) order for the Dakota County/Pine Bend Area of Air Quality Control Region 131 is evidence of EPA's determination that NSPS Subpart J is inapplicable to this gas stream. For the reasons stated in our response to stream H, your belief is not correct.

## X. SRU TGTU Process Heater

Koch's Position:

NSPS Subpart J fuel gas requirements are inapplicable because this stream falls under the exemption for facilities in which gases are combusted to produce sulfur.

EPA's response:

NSPS Subpart J §60.104(a)(2) prohibits the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing excess amounts of $SO_2$. According to your diagrams, the exhaust from the heater/reactor goes into a liquid-gas $H_2S$ recovery system. The recovered $H_2S$ is then recycled back to the feed line of the SRU. Since the $SO_2$ is converted into $H_2S$ and is not discharged into the atmosphere, NSPS Subpart J requirements are not applicable to the direct-fired heater on the reducing gas reactor within the TGTU.

Although we agree that this direct fired heater is not subject to NSPS Subpart J §60.104(a)(1) [as discussed above], we do not agree with Koch's interpretation of the heater being exempt because it is part of the sulfur recovery plant. Koch argues that the exemption for sulfur recovery plants applies to this heater. It does not. The heater and reducing gas generator are not in the SRU; the $H_2S$ stream that they generate is desired for improving the efficiency of the SRU, but is not essential for the operation of the SRU; and the recycled $H_2S$ stream would be "fuel gas" if combusted anywhere other than in the SRU or a sulfuric acid plant at the refinery (the two combustion devices exempted from being “FGCDs”).

**Y. SRU TGTU Incinerator**

Koch’s Position:

This unit is subject to, and complies with Subpart J requirements for sulfur plants.

EPA’s response:

Based on your May 14, 1999, Generic Tail Gas Treatment Unit Flow Chart, Koch’s TGTUs meet the definition of “reduction control systems”. Each TGTU has attached to it an incinerator. Koch is burning refinery fuel gas and gas from the tail gas absorber in the TGTU incinerator. The exhaust from Koch’s TGTU incinerators is a combination of exhausts from two different types of NSPS affected facilities (i.e., an SRU and an FGCD). Therefore, the TGTU incinerator is subject to both the $H_2S$ limit for the fuel gas (§60.104(a)(1)) and the $SO_2$ limit for the exhaust from a reduction control system followed by incineration (§60.104(a)(2)(i)). The more stringent of the two limits applies (in this case, the FGCD limit) unless compliance can be determined independently for each requirement. Koch monitors the refinery fuel gas for $H_2S$ prior to combustion and monitors the $SO_2$ levels in the exhaust from the TGTU incinerator. Since compliance for each requirement can be determined separately, Koch does not have to maintain the TGTU incinerator’s combined emissions below the FGCD $SO_2$ emission level, but the SO2 level (adjusted for the combustion of the fuel gas) must meet the limits under §60.104(a)(2)(i). This determination has already been established by EPA in an April 7, 1992 letter. (Enclosure 4)

**Z. Propane Flare at Koch Pipeline Company Pipeline Terminal**

Koch’s Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA’s response:

Based on the description provided, EPA understands that the only time any vapors are generated and combusted at this terminal is during periods of shut-down or malfunction. As such, and if a part of the refinery, these gases are process upset gases excluded from Subpart J, but would still be subject to §60.11(d).

EPA also understands that this pipeline terminal is a separate source and is different from the refinery, and the only physical connection to the refinery is via a product pipeline. Since it does not appear to be part of the refinery, these vapors would not be a fuel gas because they are not generated at a refinery.

In your July 9, 1999, Supplemental Submittal, you requested that EPA Headquarters act on your proposed Alternative Monitoring Plan (AMP) and proposed Flare Gas Recovery Performance Policy at the same time as issuing this applicability determination. You state that if EPA does not act on those requests at the same time, you will assume that your requests would ultimately be denied. In our August 10, 1999, meeting, we made it clear that we are willing to work with you on those two requests, but they do not affect the applicability of the regulation. We are confident that we can resolve the issues relating to those two requests, and that your requests will be approved in some form, but it will take time to work out the remaining details. Therefore, we have decided not to delay our response to your original letter from August 14, 1998, while we continue to work together on the AMP and flaring policy.

This determination has been coordinated with EPA's Office of Regulatory Enforcement, the Emission Standards Division of the Office of Air Quality Planning and Standards, the Office of General Counsel, and Several of EPA's Regional offices. If you have any questions, please contact Tom Ripp of my staff at (202) 564-7003.

Sincerely,

**S/ KEN GIGLIELLO** for

John B. Rasnic, Director
Manufacturing, Energy and Transportation Division
Office of Compliance

cc: Jim Jackson, ORE
Diane McConkey, OGC
Jim Durham, OAQPS
Annette Lang, DOJ
Patrick Foley, Region III
Patric McCoy, Region V
Jonathan York, Region VI
Bill Peterson, Region VII
Lee Hanley, Region VIII
Paul Boys, Region X
Glenna Emanuel, OC

# Air Rule Interpretation Summary Form

| Code Number | 60J.002 |
|---|---|

| Typographical error in 60.106(e)(2) | December 22, 2000 |
|---|---|

| Rule/Regulation Citation(s): | Federal Rule: X State Regulation: __ <br>Description: |
|---|---|
| 40 C.F.R. Part 60, Subpart J<br>§ 60.106(e)(2) | Standards of Performance for Petroleum Refineries |

**Interpretation Request:**

On October 17, 2000, the U.S. Environmental Protection Agency (EPA) published amendments to Title 40 Code of Federal Regulation (C.F.R.) Part 60, Subpart J in the *Federal Register*. These amendments included 40 C.F.R. § 60.106(e)(2), which states: "Where emissions are monitored by § 60.105(a)(3), compliance with § 60.105(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A." However, 40 C.F.R. § 60.105(a)(1) is a fluid catalytic cracking unit catalyst regenerator opacity monitoring requirement. Since 40 C.F.R. § 60.106(e)(2) concerns $SO_2$, it appears the reference to 40 C.F.R., § 60.105(a)(1) is a typographical error. What should be the correct reference in 40 C.F.R. § 60.106(e)(2)?

**Determination:**

The reference to 40 C.F.R. § 60.105(a)(1) in 40 C.F.R. § 60.106(e)(2) is a typographical error. The correct reference in 40 C.F.R. § 60.106(e)(2) should be to 40 C.F.R. § 60.104(a)(1). Therefore, 40 C.F.R. § 60.106(e)(2) should read as follows: "Where emissions are monitored by § 60.105(a)(3), compliance with § 60.104(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A."

<u>Bibliography</u>:


40 C.F.R. Part 60, Subpart J (1998).

40 C.F.R. Part 60, Appendix A (1998).

65 Fed. Reg. 61,755 (2000) [Published: Oct. 17, 2000].