Bay Area Air Quality Management District
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Permit Evaluation
and
Statement of Basis
for
MAJOR FACILITY REVIEW PERMIT
Reopening – Revision 2.0

for

Chevron Products Company
Facility #A0010

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May 2006

Application 12429

Reopening of Title V permit for Chevron

Statement of Basis

The District issued the initial Title V permit to this facility on December 1, 2003. The District issued a reopened permit that amended flare and Regulation 9-10 requirements, corrected errors, and incorporated some new sources and permit conditions on December 16, 2004.

On October 8, 2004, EPA sent a letter containing two objections to the permit and various comments. The letter is attached in Appendix B. The permit was revised to address the objection issues in a reopening of the permit that was proposed on February 1, 2005. The revised permit was issued on April 12, 2005**.**

This reopening addresses issues identified in comments in the October 8 letter (note that EPA commented on five refineries in this letter. Not all comments concern this facility.) Changes in applicable requirements authorized in several Authorities to Construct are also being incorporated in this action. In addition, some issues raised in the refinery's appeal to the 12/16/04 permit and some refinery comments are addressed.

The reopening is limited to the changes made to the permit. This statement of basis discusses the changes made by this reopening. It also provides additional analysis supporting certain applicability determinations. Where the additional analysis did not result in a permit change, the analysis is provided for information only. The permit is not being reopened with respect to those issues.

This statement of basis does not address the factual and legal basis for any other permit terms. These are addressed in the comprehensive statements of basis that were prepared for the initial issuance of the permit and for the reopening issued on December 16, 2004. These are available on request.

The revisions include the incorporation into the Title V permit of permit modifications made in seventeen District permit applications. The potential increase of criteria pollutant emissions for each of these applications is summarized as follows and all these emission increases have been offset at a ratio of 1.0 to 1.15 in compliance with BAAQMD Regulation 2, Rule 2:

Permit Application #	Pollutant Increase (tons/yr)				
	NOx	CO	POC	SO2	PM
2719	0.000	0.000	2.300	0.000	0.000
6311	0.000	0.000	0.000	0.000	0.000
6523	1.030	0.150	0.100	0.157	0.034
6643	0.000	0.000	0.000	0.000	0.000
6851	0.000	0.000	0.000	0.000	0.000

6896	0.000	0.000	0.216	0.000	0.000
7693	0.000	0.000	0.032	0.000	0.000
8294	0.000	0.000	0.000	0.000	0.000
8450	0.000	0.000	0.000	0.000	0.000
8451	0.000	0.000	0.300	0.000	0.000
9329	0.000	0.000	0.000	0.130	0.180
9503	0.000	0.000	0.000	0.000	0.000
10401	0.000	0.000	0.000	0.000	0.000
10999	0.000	0.000	0.000	0.000	0.000
11380	0.000	0.000	0.000	0.000	0.000
11989	0.000	0.000	0.000	0.000	0.000
11990	0.000	0.000	0.000	0.000	0.000
Total	**1.030**	**0.150**	**2.948**	**0.287**	**0.214**

Changes to the Permit

Section I

The following language was added as Standard Condition I.B.12: "The permit holder is responsible for compliance, and certification of compliance, with all conditions of the permit, regardless whether it acts through employees, agents, contractors, or subcontractors. (Regulation 2-6-307)." The purpose is to ensure that all activities at the facility comply with all applicable requirements.

Section II

Two new sources (S-4405 and S-7010) were added to the New Source review Table II. These sources were associated with application numbers 7693 and 6523, respectively. S-9304 has had a new condition number added to Table II per application number 6896. A-4429 will be added to Table II B per application number 6643.

S-3226 will be added to Table II per application 9329.

A-0072 and A-0073 is being corrected to reflect 10 ppmv per Regulation 9-9-401, which allows for a change in the emission limitation based on efficiency based on a comment received from Chevron.

For abatement devices A-607, A-611, A-615, A-630, and A-631 now lists both compliance options allowed per 40 CFR 61.349(a)(2)(ii).

A-919 has been added to Table II B per a request made in Chevron’s permit appeal.

Several Tanks has been removed from Table IIC and Table IIA2 since these tanks have been demolished.

S-1726, 1727, 1757, and S-1758 has been removed from Table IIB since these tanks have been dismantled.

Section IV

Complex Applicability Determinations:

MACT Subpart CC applicability for flares

Subpart CC applies to, among other things, miscellaneous process vents from petroleum refining process units (40 CFR 63.640(c)(1)). “Miscellaneous process vent” means a gas stream containing greater than 20 parts per million, by volume, organic HAP that is continuously or periodically discharged during normal operation of a petroleum refining process unit meeting the criteria specified in Sec. 63.640(a) (40 CFR 63.641). Miscellaneous process vents do not include gaseous streams routed to a fuel gas system nor do they include episodic or non-routine releases (40 CFR 63.641).

Subpart CC also contains a more general exemption from testing, monitoring, recordkeeping, and reporting requirements for refinery fuel gas systems or emission points routed to refinery fuel gas systems (40 CFR 63.640(d)(5)).

Subpart CC defines “emission point” to mean an individual miscellaneous process vent, storage vessel, wastewater stream, or equipment leak associated with a petroleum refining process unit (40 CFR 63.641). “Fuel gas system” means the offsite and onsite piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery (40 CFR 63.641). “Combustion device” means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the combustion of organic hazardous air pollutant vapors (40 CFR 63.641).

The definition of “fuel gas system” clearly indicates that a system begins at the emission point. Once the gas is in the collection system, the fuel gas exemptions apply, even if the collected gases are subsequently routed to a flare. EPA, in its October 8, 2004 letter, disagreed with that interpretation. EPA’s rationale appears to be that the fuel gas system begins at the fuel gas compressor (and presumably any piping leading directly to the compressor). However, EPA’s interpretation renders the part of the definition of “fuel gas system” that includes gathering streams a nullity. Moreover, the definition indicates with equal clarity that a “fuel gas system” remains such even when the gas is routed to a combustion device which, as noted above, is defined to include flares.

An alternative rationale exists in that gases vented to the flares in question are not within the definition of “miscellaneous process vents.” At all of the affected refineries, process gas collected by the gas recovery system are routed to flares only under two circumstances: (1) situations in which, due to process upset or equipment malfunctions, the gas pressure in the flare header rises to a level that breaks the water seal leading to the flare; or (2) situations in which, during process startups, shutdowns, or process upsets, the quality of the gas falls to a level such that it cannot be introduced into the fuel gas system. Episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring [sic], and catalyst transfer operations are, by definition, not miscellaneous process vents, and are not subject to Subpart CC.

Cooling tower monitoring

The District has determined that best modern practices for operation of refinery heat exchangers is frequent monitoring for potential heat exchanger leaks. The District has reviewed the current practice of Bay Area refineries, and has determined that daily visual inspection, plus water sampling and analysis for indicators of hydrocarbon leaks once per shift, is the best modern practice. A cooling tower that is maintained using best modern practices is exempt from Regulation 8-2. The facility has the burden of keeping records necessary to demonstrate that it qualifies for the exemption The District has determined that this facility is using best modern practice to monitor cooling tower water for indications of heat exchanger leaks. Regulation 8-2 will be removed from the source-specific applicable requirement table for sources S-4073, S-4076, S-4078, S-4172, S-4173, S-4187, S-4191, S-4329, S-6051, S-6054, and S-6055.

Based on a comment from EPA regarding preventive maintenance procedures and specific monitoring techniques Chevron provided the following information:

- **DESIGN.** Anticipated corrosion rates are a factor in selecting the metallurgy and wall thicknesses of heat exchangers. At a minimum, equipment is designed to run between scheduled maintenance turnarounds without developing leaks. If corrosion rates exceed expectations, options are considered, e.g., upgrade metallurgy, install sacrificial anodes.
- **INSPECTION.** Heat exchangers are inspected and hydrotested on a regular basis during maintenance turnarounds to determine corrosion rates and to confirm that there are no leaks. Inspection intervals are determined by API Standard 510 or internal inspection records (whichever is shorter).
- **CORROSION PREVENTION - 1.** Cooling water is treated to minimize corrosion. Specifically, pH is continuously monitored and adjusted to maintain it in an acceptable range. Similarly, corrosion prevention chemicals are monitored (either continuously or weekly) and addition rates adjusted to maintain an acceptable concentration.
- **CORROSION PREVENTION - 2.** Heat exchanges are periodically backflushed if they are susceptible to fouling or the collection of sediments. Both items can accelerate corrosion
- **LEAK DETECTION (MONITORING).** For most of our cooling towers, the leak detection program has three components:
    - Operators inspect towers twice daily for evidence of oil or unusual odors.
    - Operators inspect "tell-tales" installed at the high points of water lines running from heat exchangers to the cooling towers. Bubbles collect in these if light hydrocarbons are leaking into the water. Note that one cooling tower also requires monthly analysis of the water for VOCs.
    - Bleach consumption rates are monitored. Bleach is added to the cooling water to control bacteria and algae growth. A hydrocarbon leak into the water also consumes bleach and will resulted in higher addition rates.

In conjunction with it's determination of Best Modern Practices, the District expects that Chevron will continue to follow these maintenance procedures.

NSPS QQQ requirements and Regulation 8-8 Wastewater requirements for slop oil vessels

Chevron's slop oil tanks are subject to Subpart Kb (see Table IV G.1.6) therefore the slop oil tanks are not subject to Subpart QQQ per Section 60.692-3(d):

> 60.692-3(d) Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in §§60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, subparts K, Ka, or Kb are not subject to the requirements of this section.

Chevron's slop oil tanks meet the definition of a slop oil vessel per Reg. 8-8-213 since the tanks do dewater the slop oil. Section 8-8-305 is an applicable requirement for these sources, and prohibits the storage of any oil-water separator and/or air flotation unit sludges in an oil-water separator slop oil vessel unless such oil-water separator slop oil vessel is equipped with specified controls. This requirement has been added to Table IV G.1.6. Chevron complies with this requirement, and does not store sludge in these tanks.

40 CFR 61 Subpart FF Applicability

Chevron complies with 40 CFR Subpart FF by meeting the requirements of 61.342(e). Non-aqueous streams are managed per the requirements of 61.342(e)(1) by complying with the equipment standards 61.343 through 61.350. Aqueous streams comply with 61.342(e)(2)(i). Table D.1.1 has been modified to address the non-aqueous streams.

Compliance with Regulation 9-1-313.2

The District is deleting of Title V permit conditions in the five Bay Area refinery permits related to monitoring for compliance with 9-1-313.2. 9-1-313 allows three options for compliance, but is complied with at all Bay Area refineries through section 313.2, which requires operation of a sulfur removal and recovery system that achieves 95% reduction of H_2S from refinery fuel gas. Conditions were established in the 2003 issuance of these permits to periodically verify that a 95% reduction is being achieved. Though details vary amongst the five refineries, all permits require some form of compliance demonstration, generally involving inlet-outlet source testing. The refineries have consistently objected to these conditions, noting that source testing for H_2S reduction is, on the one hand, costly and a significant safety risk, and on the other, unlikely to yield data useful to determining compliance.

The monitoring in all five refinery permits was established pursuant to 2-6-409.2, which provides that, where the applicable requirement does not contain periodic monitoring or testing, "the permit shall contain periodic monitoring sufficient to yield reliable data from the relevant time periods that is representative of the source's compliance with the permit." This provision was established in 2-6 to satisfy EPA's program approval criteria found in 40 CFR 70.6(a)(1)(iii), commonly known as the periodic monitoring requirement. The District has consistently applied a balancing test to determinations of periodic monitoring, considering, among other things, the likelihood of a violation during normal operation, variability in the operation and in the control device, the technical feasibility and probative value of the monitoring under consideration, and cost. Applying these factors to 9-1-313.2, the District now believes that compliance with 9-1-313.2 is sufficiently assured without the addition of Title V monitoring.

A periodic monitoring determination should take as its starting point the intent of the underlying requirement. While some District regulations impose a reduction efficiency with the intent that it be measured on an ongoing basis, other regulations use reduction efficiency to describe the requisite design of equipment to be installed. The latter are sometimes referred to as design standards.

Regarding 9-1-313.2, both the rule language and contemporaneous explanations of the rule suggest that the 95% reduction requirement was intended as a design standard. Furthermore, the target of 95% was aimed at ensuring that no significant fuel gas stream went untreated, rather than acting as a performance standard for treatment systems. 9-1-313 prohibits operation of a refinery of a certain size unless one of three conditions is met, one of which (§ 313.2) is that "*there is a* sulfur removal and recovery system that removes and recovers, on a refinery wide basis, 95% of H2S from refinery fuel gas" (emphasis added). This phrasing places primacy on the presence of a system capable of achieving a reduction, rather than achievement of the reduction. Moreover, another of the three possible methods of compliance with Section 313 (§ 313.3) allows (prior to a certain date) compliance merely by way of an enforceable commitment to construct such a system. This third compliance option reinforces the inference that the primary intent of Section 313 was to require operation of a sulfur recovery and removal system.

9-1-313 was adopted in 1990, at a time when all but one Bay Area gasoline-producing refinery were already operating SRU's. The remaining gasoline-producing refinery, Pacific Refining (which has since closed), was instead using a caustic scrubbing system, and had a history of causing odor problems in the community due, in part, to high H2S levels in fuel gas. The 1990 District staff reports evidence that the primary purpose of the rule was to require installation of an SRU at this facility. This also happens to be the purpose of the Section 313.3 compliance option. The staff reports do not evidence a concern with ensuring a certain level of performance at facilities with existing SRU's. Nor do the staff reports characterize Section 303 as being in any way intended to fulfill a requirement of the federal Clean Air Act. The 1990 staff reports indicate that Bay Area refineries with SRU's were known at the time to be reducing sulfur content in fuel gas to well below applicable regulatory standards.

In 1995 the District revised 9-1-313.2 to add a requirement that a refinery removing more than 16.5 tons of elemental sulfur per day must install a sulfur recovery plant or sulfuric acid plant. The content of the accompanying staff report suggests that, once again, this rulemaking was directed at one facility, Pacific Refining. The caustic scrubbing system in use at Pacific Refining had not resolved the odor problem at the refinery. The rule revision was intended to require Pacific Refining to install a sulfur plant. Most relevant to today's proposal, the staff report includes a statement that while a caustic scrubbing system can be expected to achieve a 95% H2S reduction, reduction at an SRU typically exceeds 99%.

The language of 9-1-313.2 and District staff reports are consistent with the view that the intent of the rule was to require Bay Area refineries to install and operate an SRU. Though there is an expressed assumption that reduction of better than 99% can be achieved by an SRU, there is no mention in the rule or in the staff reports of how a 95% reduction could be verified on an ongoing basis. This is consistent with the characterization of section 313.2 as a design standard that is satisfied by installation and operation of an adequately designed system.

The discussion that follows explains why periodic monitoring would not be appropriate even if the 95% reduction requirement of section 313.2 is characterized as a performance standard. Although the following discussion can stand alone as a justification for not imposing additional monitoring, it can also be viewed as overlapping with discerning the original intent of the rule. The technical considerations weighing against establishing monitoring through Title V today are synonymous with the policy reasons for why monitoring was not included in the rule as adopted in 1990, and why that rule is most accurately viewed as a design standard.

The District believes that monitoring to verify a 95% reduction is not appropriate. The monitoring would be costly and burdensome. To attempt measurement of inlet and outlet concentrations would require that samples be taken from multiple points simultaneously. The refineries have asserted this is not possible. The District acknowledges that doing so is at the least costly, complicated, and, to the District's knowledge, unprecedented. The task is made more difficult due to the risks of exposure to H2S during sampling, particularly at inlet concentrations. Safety precautions would require 2-3 personnel at each sample point, and additional precautions during sample transport and handling. Because the standard is expressed as a refinery-wide standard, samples would need to be taken simultaneously at each fuel gas treatment system in order to determine compliance.

A monitoring regime may be burdensome and yet still justifiable if, among other things, results are accurate and probative regarding compliance with the standard. This is not the case regarding the 95% reduction goal of section 313.2. The accuracy of inlet-outlet source testing would be hampered by the limits of available methods for analyzing H2S samples at these levels of dilution. Moreover, many of the other sulfur species present interfere with measurement of H2S, and as a result routine fluctuation in sulfide species will tend to confound calculations comparing inlet and outlet H2S concentrations. There is no recognized method for quantifying and taking this into account.

Moreover, the District believes the margin of compliance with the 95% reduction goal is likely very large. Of course, due to the considerations discussed above, this cannot be verified with significant accuracy. However, each refinery has regulatory and operational reasons for employing an SRU to maintain H2S concentrations at very low levels. NSPS Subpart J, for instance, requires that fuel gas contain no more than 230 ppm H2S. Concentrations at the Bay Area refineries are typically far below this level in all gas combusted as fuel. While the actual percentage of reduction would depend on the inlet concentrations, the low concentrations found post-SRU fuel gas yields a safe assumption that reductions well in excess of 95% are occurring.

In summary, 9-1-313 was adopted primarily to force installation of an SRU at a single refinery that no longer operates. Though not stated in the staff reports, the expression of a 95% reduction goal was likely inserted in the rule to ensure that any SRU installed would address fuel gas comprehensively, not merely in part. H2S reduction efficiency for an entire fuel gas system can be estimated but cannot be accurately measured. The District believes there is a high degree of certainty that when all fuel gas is processed in an SRU, an H2S reduction efficiency well above 95% will be achieved. However, monitoring for this result would entail high costs and safety risks for measurements insufficiently exact to be relied on as a measurement of compliance. Such monitoring is therefore not justified for a District regulation that has no historical and no direct functional relationship to a federal Clean Air Act requirement.

Applicability of NSPS Subpart J to thermal oxidizers

The District is revising the permit to indicate the applicability of NSPS Subpart J at thermal oxidizers A-414, A-620, A-622, A-623, A-624, A-627, and A-628.

This revision is responsive to EPA's comments relative to the Bay Area refinery permits that a thermal oxidizer located at refinery is a "fuel gas combustion device" within the meaning of § 60.101(g) and therefore subject to Subpart J, provided other applicability criteria are met. EPA's comments are based on the definition of "fuel gas" found at§ 60.101(d) as "any gas which is generated at a petroleum refinery and which is combusted." EPA made this comment on earlier versions of the refinery Title V permits, but did not include the issue in its list of reopening issues either on October 8, 2004, or March 15, 2005.

NSPS Subpart J applies to a "fuel gas combustion device … which commences construction or modification after June 11, 1973." (40 CFR § 60.100(b).) Any device subject to Subpart J shall not "[b}urn … any fuel gas that contains hydrogen sulfide (H2S) in excess of 230 mg/dscm." (40 CFR § 105(a)(1).) Subpart J defines fuel gas as "any gas which is generated at a petroleum refinery and which is combusted." (40 CFR 61.101(d)).)

The question that has arisen at some Bay Area refineries is whether a thermal oxidizer at a waste water treatment unit or a gas loading rack is a "fuel gas combustion device." It will be argued that although these abatement devices are combusting gas generated at a refinery, the gases are typically not sufficiently rich in hydrocarbons to support combustion and so are not "fuel gas," both in the common sense of that term and the intended meaning of that term as used in NSPS J. Secondly, it will be argued that only gases generated at "petroleum refinery processing units" should be considered as "fuel gas," and that this would preclude applicability to wastewater treatment systems and gas loading racks. Finally, it will be argued that certain gases combusted at thermal oxidizers are not subject to the hydrogen sulfide standard of NSPS J because they are not compatible with amine treatment.

The District views these arguments as being for the most part analytically distinct. Accordingly, they are addressed in order below.

Does "Fuel Gas" Refer Only to Gases That Can Support Combustion?

As noted above, NSPS J defines "fuel gas" as "any gas which is generated at a petroleum refinery and which is combusted." Aside from the exemption of specific gas streams, the scope of this definition appears comprehensive. A textual argument might be made that the reference to "gas" in the phrase "gas which is generated," should be read as synonymous with "fuel gas." In other words, that "fuel gas" should be afforded its common-sense meaning as gas capable of supporting combustion, rather than the broader literal meaning given to it by the section 101(d) definition. This interpretation runs counter to the common practice for reading definitions, i.e., by importing meaning from the defined phrase into the definition itself.

"Fuel gas" was defined in the initial promulgation of NSPS J. In the proposed rule, "fuel gas" meant, in relevant part, "process gas and/or natural gas or any other gaseous mixture which will support combustion." 38 FR 15408 (June 11, 1973). In the final rule, "fuel gas" was defined as "any gas which is generated by a petroleum refinery process unit and which is combusted." 39 FR 9315 (March 8, 1974). Thus the phrase "gaseous mixture which will support combustion" was replaced by the phrase "[gas] which is combusted." This raises the question whether any change in meaning from proposal to final was intended.

The preamble to the final rule discusses a different change regarding fuel gas combustion (exemption of process upset gases), noting that it "do[es] not represent any change in the Agency's original intent." *Id.*, at 9310. From the fact that changes to the "fuel gas" definition are not mentioned, it might be inferred that no changes in meaning were intended (i.e., since discussion was devoted to changes that did not alter intent, one would presume any changes that did would have merited discussion). However, the comparison of proposed to final rule combined with the supposition that no change in intent occurred merely begs the question of which version better represents EPA's true intent.

The stronger presumption, however, is that a change in rule language intends a change in meaning. The change in language clearly has a broadening effect: a gas that, standing alone, will not support combustion will nevertheless combust if introduced into a sufficiently robust environment. EPA could quite reasonably have decided that basing applicability of a standard on the capacity of a gas stream to support combustion places too much weight on a variable facet of operations. In this plausible scenario, the final rule language could be viewed as simply a more accurate statement of EPA's original intent.

Other federal standards contain definitions of "fuel gas" that clearly limit the phrase to gases that can support combustion. See, e.g., NSPS VV, SOCMI HON. However, these are distinct standards established for purposes other than control of SO2 emissions. Inferences drawn from comparing definitions of "fuel gas" are ambiguous at best. These more specific definitions would seem to cut against, rather than support, arguments made by the refineries. That EPA can, when it chooses, define "fuel gas" to exclude gases not supporting combustion could lead one to infer that the literal meaning of section 60.101(d) is also the intended meaning.

Is "Fuel Gas" Limited to Gas Generated at Petroleum Processing Units?

As initially promulgated, "fuel gas" was defined as "gas generated at a petroleum refinery process unit." In the 1973 proposed rule, this phrase appeared in the definition of "process gas" but not in the definition of "fuel gas." It was added into the definition of "fuel gas" in the final rule, without explanation. A "refinery process unit" is, and will be, defined in section 101(f) as "any segment of a petroleum refinery in which a specific processing operation is conducted."

There is little if anything to illuminate the intended meaning of "process," which in this provision is used to define itself. There is arguably a common usage that refers only to operations that act upon petroleum and transform it towards some end product. Background documents for the 1974 rule explain that "[r]efinery processes, such as distillation and fluid catalytic cracking, produce substantial quantities of 'process gas…." The same document states that "[f]uel gas is produced in a refinery from a wide variety of processes including: crude oil separation, catalytic cracking, hydrocracking, coking, and reforming." However, there is no indication in these background documents that the phrase "refinery process units" was intended to be so limited.

"Process" could also be used in a broader sense to include waste water treatment plants, hydrogen plants, and other ancillary process that do not involve petroleum. In any case, EPA subsequently amended the definition of fuel gas to refer to any gas "generated at a refinery." Though no explanation was offered for the change, the plain language of the rule as revised would appear to foreclose whatever inferences could have been based on the earlier formulation. It might be argued that interpreting "process" to include any refinery operation deprives the definition of purpose. However, this broader interpretation of "process" does distinguish gas generated onsite from gas imported to the refinery (e.g., pipeline natural gas). Subsequent revision to the standard clarifying the exemption of pipeline gas is consistent with the idea that the reference to "refinery process unit" in the initial definition of "fuel gas" was intended to serve this same purpose.

<u>Does "Fuel Gas" Refer Only to Gas Streams Subject to Amine Treatment?</u>

There are clear indications in the regulatory history of NSPS J that the intent of the rule was to apply only to gases subject to amine treatment. Background documents to the initial proposal discuss amine treatment as the cost effective available control. In 1979, the rule was revised to answer two specific questions: were Thermofor catalytic cracking units treated the same as fluid catalytic cracking units under the regulation (answer: yes); and were auxiliary fuels burned along with gases generated by exempt units subject to the standards (answer: yes). The preamble to this direct-final rulemaking states that the hydrogen sulfide standard of NSPS J is "based on amine treating of refinery fuel gas." 44 FR 13481 (March 12, 1979). The definition of "fuel gas" was accordingly changed to exclude gases generated at catalytic cracking units, because these gases are chemically unsuitable for amine treatment.

This raises the question of whether other gas streams not susceptible to amine treatment should be considered exempt from the hydrogen sulfide standard or NSPS J. The idea finds considerable support in the original background documents and the 1979 preamble discussion. The 1979 preamble notes that "amine treating can be used, and in most major refineries normally is used, to remove hydrogen sulfide from . . . refinery fuel gas streams." *Id.* There is thus an inference that the intent of the standard was to apply only to fuels found in refinery fuel gas systems, or capable of being collected and used in fuel gas systems, because these systems are typically coextensive with the gas streams that are processed by an amine treater at a refinery.

However, there is no reference is in the text of the rule itself to amine treatment compatibility as a criterion of applicability. Under the terms of the rule, gas generated at refinery is either "fuel gas," and therefore subject, or not. Rather than create an explicit exemption based on amine treatment compatibility, EPA chose to specifically exclude those gas streams it knew to require different treatment. The argument for limiting applicability based on amine treatment compatibility therefore finds no foothold in the text of the rule. Presumably, other sources could be expected to comply with the standard using a different control technique (e.g., caustic scrubbing); or normally produce gases of sufficiently low sulfur content as to be inherently compliant.

Incorporation of NSPS Subpart J

This discussion begins by noting that the arguments that have been raised against applying the hydrogen sulfide standard of NSPS J to thermal oxidizers are analytically distinct. Though mostly true, it may be that certain arguments shade into others. For instance, the argument that only gases compatible with amine treatment were intended to be subject to the standard, which in turn tends to implicate only gases commonly in the fuel gas system, lends some further weight to the textual argument that "fuel gas," as defined in section 101(d), should be accorded its common sense, as opposed to its literal meaning. Further weight is added by a seeming emphasis, evidenced throughout the regulatory history, on gases generated at units that process petroleum as the subject of controls, which units in turn tend to be the primary source of fuel gas used to support combustion at refinery heaters and boilers.

However, the potential for tying together these different strands of evidence has never been taken up by EPA. EPA has established a consistent record of interpreting NSPS J to apply broadly and according to its literal terms. See, e.g., December 2, 1999, letter from J. Rasnic, EPA, to P. Guillemette, Koch Refining Co.. The District assumes that EPA's longstanding interpretation would receive substantial deference from a reviewing court. Incremental changes to regulatory language over time, though sometimes unexplained, have tended to support these broader readings. The District speculates that the broader interpretation finds its policy justification in the desire to close potential loopholes -- that is, to remove any incentive to route treatable gas streams away from treatment. Though this may not be consistent with how some understand the original intent of the rule, it is nevertheless a legitimate and rational regulatory goal that finds ample support in the plain language of the rule. The District notes that, to its knowledge, EPA has never analyzed the technical feasibility, benefits, and costs of alternative controls and their application to gas streams not compatible with amine treatment. As a result, the practical consequences of application of NSPS J to the thermal oxidizers in question are not clear.

In a Consent Decree with EPA and the District, Chevron has accepted applicability of Supart J at these thermal oxidizers. To implement this, Chevron submitted applications 14307 and 14308 to the District. The District is incorporating these permit conditions into the Title V permit. Therefore, no schedule of compliance is needed.

A new condition # 23201 was added to the Title V Permit Section VI. Tables IV and Tables VII (Abatement, A.1.1, A.3.2, A.3.3, B.5.1, and H.2.1) now include condition #23201, which subjects the sources to NSPS Subpats A and J.

Other Revisions

FCCU monitoring for Regulations 6-310/11 includes transformer rectifier set secondary current on a daily basis and continuously monitoring and recording the inlet temperature of the Electrostatic Precipitator (ESP) per condition 11066 part 7a. The district has determined that these parameters assure the proper operation of the ESP and verify compliance with both 6-310/11. These parameters will be added to the monitoring Table VII C.2.1.

Table IV Abatement will be created in order to include NSPS subpart J into the permit for Thermal Oxidizers.

Table IV A.1.1 will be changed to reflect the current version of NSPS Subpart GG.

Table IV A.1.1 will now include 60.334 (h, i) based on the comment from EPA and information provided by Chevron.

Table IV A.4.1 will be changed to include S-7010 and condition #20366 per application 6523.

Table IV A.4.1 will have S-4118, 4119, 4126, 4127, 7524, 7528, 7510,and 7520 removed since these sources were either replaced or removed.

Table IV B.2.1 will be changed to include condition #'s 7880 and 20666 per application 6896.

Table IV B.4.1 will be changed to include S-4405 and condition #20863 per application 7693.

Table IV C.1.1 will be removed Regulation 8-2 since the facility meets best modern practices.

Table IV C.2.1 will now include 40 CFR 63 subpart UUU per application 10999.

Table IV C.3.1 will now include 40 CFR 63 subpart UUU per application 10999. This Table will now be updated based on a comment from Chevron regarding a recent rule amendment.

Table IV C.3.1 will be changed to include S-4354 and S-4360 and condition # 18337 per application 2719.

Table IV D.1.1 will be corrected to reflect Regulation 8-10-502. NESHAP subpart FF has also been added to this table. Condition #20620 will be removed since it merely restates timelines from 40 CFR 63 subpart UUU.

Table IV D.1.1 will now include an updated NESHAP Title 40 Part 61 Subpart FF. This Table will now be updated to more accurately reflect Chevron's operation based on the comment from EPA and information provided by Chevron.
Table IV E.2.1 will now include 40 CFR 63 subpart UUU per application 10999.

Table IV E.3.1 will now include S-3226 per application 9329.

Table IV E.3.1 will have S-3140 removed since the tank has been dismantled.

Table IV F.1.0 will be created for Storage Tanks exempt from permits but subject to permit conditions.

Table IV F.1.1 will now include S-3226 per application 9329.

Table IV F.1.2 will have several tanks removed since the tanks have been demolished. For details see Chevron's Revision 2 comments Attachment 2.

Table IV F.1.4 will now include 61.349(a)(2)(i) and 61.349(a)(2)(ii), and it will have 61.345(a)(4) removed based on the comment from EPA and information provided by Chevron.

Table IV F.1.7 will have S-1726, 1727, 1757, and S-1758 removed since the tanks have been demolished. For details see Chevron's Revision 2 comments Attachment 2.

Table IV F.1.10 will now include condition #2856 for S-399 per application 10401.

Table IV F.1.11 will now include condition #1069 for S-1637 per application 8294.

Table IV F.1.12 will now include 61.349(a)(2)(i) and 61.349(a)(2)(ii), and it will have 61.345(a)(4), 61.349(a)(1)(ii), and 61.349(a)(2)(iv) removed based on the comment from EPA and information provided by Chevron.

Table IV F.1.14 will now include condition #21307 for S-1645 per application 8451.

Table IV G.1.1 will have 61.342(c)(2), 61.342(c)(3), and 61.342(d) removed since the facility complies with 61.342(e).

Table IV G.1.1 will now include an updated NESHAP Part 61 Subpart FF. This Table will now be updated to more accurately reflect Chevron's operation based on the comment from EPA and information provided by Chevron.

Table IV G.1.4 will no longer reference sections 8-8-112, 8-8-210, and 8-8-502. Section 8-8-313 will be added. These changes were made as a result of Chevron's permit appeal.

Table IV G.1.5 will now include an updated NESHAP Part 61 Subpart FF. This Table will now be updated to more accurately reflect Chevron's operation based on the comment from EPA and information provided by Chevron.

Table IV G.1.8 will now include 61.349(a)(2)(i) and 61.349(a)(2)(ii), and it will have 61.345(a)(4), 61.349(a)(1)(ii), and 61.349(a)(2)(iv) removed based on the comment from EPA and information provided by Chevron.

Table IV H.2.1 will no longer contains 40 CFR 61.349(a)(1)(ii) and (iv) based on a comment within the Chevron permit appeal.

<u>Section VI</u>

The following Permit conditions will be either added or modified to incorporate new A/C's and P/O's:

Permit condition #	1046(application 9329)
	1069(application 8294)
	2856(application 10401)
	7880(application 6896)
	12842(application 11380)
	18337(application 2719)
	18945(application 9503)

20330(application 6643)
20361(application 6851)
20366(application 6523)
20666(application 6896)
20863(application 7693)
21232(application 10324)
21307(application 8451).

Condition 12842 will be changed from daily monitoring to once per 24-hour period per application 11380.

Condition 14596.3 will be added to the permit from the district databank.

Condition #18137.3 will be deleted to allow operating flexibility to the facility. The facility was requesting to switch materials from non-exempt to exempt without landing the roof or cleaning the tank. Deletion of this condition will allow this to occur. The facility will be responsible to determine whether the contents are exempt or not since a tank with non-exempt material may not mix and become exempt when exempt material is added. The lighter, non-exempt materials will have the tendency to remain on top of the exempt materials. A switch to exempt stock may occur regardless of whether the 8-5-117 exemption is listed in the permit. The facility would have the burden of proving that it qualified for the exemption. Moreover, to be exempt from section 402.2 monitoring, the facility would have to show that non-exempt stock were not present in the tank at any point during the relevant time period.

Condition #20620 will be removed since it merely restates timelines from 40 CFR 63 subpart UUU. This change will be made based on several applications (10999, 11989, and 11990).

Condition #21232 will be changed to reflect that S-4154 does not have a CEM.

Condition #7880 will now reference S-9304.

Section VII

Table VII Abatement will be changed to include the NSPS subpart J provisions.

Table VII A.1.1 will be changed to reflect the current version of NSPS Subpart GG.

Table VII A.4.1 will be modified to include S-7010 and condition # 20366 per application 6523.

Table VII A.4.1 will have S-4118, 4119, 4126, 4127, 7524, 7528, 7510,and 7520 removed since these sources were either replaced or removed.

Table VII B.2.1 will be modified to include condition #’s 7880 and 20666 per application 6896.

Table VII B.4.1 will be modified to include S-4405 and condition # 20863 per application 7693.

Table VII C.2.1 will now include 40 CFR 63 subpart UUU per application 10999.

Table VII C.2.1 will now include daily TR set readings and continuous temperature monitoring as required by condition 11066 part 7a.

Table VII C.3.1 will be modified to include S-4360 per application 2719.

Table VII C.3.1 will now include 40 CFR 63 Subpart UUU per application 10999. This Table will now be updated based on a comment from Chevron regarding a recent rule amendment.

Table VII D.1.1 will now have NESHAP subpart FF to address a comment made by the EPA regarding non-aqueous waste streams. Tables VII D.1.1 and G.1.6 will remove 61.342(c)(2), 61.342(c)(3), and 61.342(d) since the facility complies with 61.342(e).

Table VII E.2.1 will now include 40 CFR 63 subpart UUU per application 10999.

Table VII E.3.1 will now include S-3226 per application 9329.

Table VII E.3.1 will have S-3140 removed since the tank has been dismantled.

Table VII F.1.0 will be created for Storage Tanks exempt from permits but subject to permit conditions.

Table VII F.1.1 will now include S-3226 per application 9329.

Table VII F.1.2 will have several tanks removed since the tanks have been demolished. For details see Chevron’s Revision 2 comments Attachment 2.

Table VII F.1.7 will have S-1726, 1727, 1757, and S-1758 removed since the tanks have been demolished. For details see Chevron’s Revision 2 comments Attachment 2.

Table VII F.1.10 will now include condition #2856 for S-399 per application 10401.

Table VII F.1.11 will now include condition #1069 for S-1637 per application 8294.

Table VII F.1.14 will now include condition #21307 for S-1645 per application 8451.

Table VII G.1.4 will no longer reference sections 8-8-112, 8-8-210, and 8-8-502. Section 8-8-313 will be added. These changes will be made as a result of Chevron's permit appeal.

Table VII G.1.6 will be modified to include condition #20361 for S-3127 per application 6851.

Table VII G.1.6 will be modified to include monitoring required for 8-8-305.1.

Table VII H.2.1 will be corrected to show the monitoring citation as 61.356(h) as opposed to 61.349(g). The monitoring associated with 61.349(a)(2) will be changed to include monitoring for carbon adsorption.

Table VII Abatement will now include A-919 and provides both compliance options allowed per 40 CFR 61.349(a)(2)(ii). This table also allows the use of portable G/C monitoring. This change will be made per Chevron's permit appeal.