RTP ENVIRONMENTAL ASSOCIATES, INC.®

October 27, 2008

Via Electronic Mail

Brian Gustafson, Administrator
Air Quality Program
Department of Environment and Natural Resources
523 East Capitol
Pierre, SD 57501

Re: Draft Prevention of Significant Deterioration Permit No. 28.0701 for Hyperion Energy Center

Dear Mr. Gustafson:

On behalf of Hyperion Refining LLC ("Hyperion"), we have completed our review of the referenced Prevention of Significant Deterioration ("PSD") permit. We concur with the conclusion reached by the Department of Environment and Natural Resources ("DENR") that Hyperion will construct and operate in compliance with all state and federal air quality requirements established to protect public health and the environment. In addition, we commend DENR staff for their thorough and detailed review of Hyperion's air permit application and for drafting a PSD permit that is clear, stringent, and readily enforceable. This draft permit, with the revisions discussed in Enclosures A to C with this letter, will result in the Hyperion Energy Center being the cleanest and most advanced refinery in the United States.

Enclosure A lists various requests and recommendations for changes to the PSD permit. These changes include corrections of calculation errors and typographical errors, minor clarifications, and a small number of substantive revisions to permit requirements.

Enclosures B and C address the draft permit requirements for redesigning the more than 100 storage vessels at the Hyperion Energy Center ("HEC") to include gas blanketing systems and vapor collection systems and for installing and operating vapor incinerators. As you know, this requirement is inconsistent with the configuration proposed in our air permit application and is unprecedented. For the reasons discussed in these enclosures, we request that these requirements be removed and that the configuration reflected in our permit application be incorporated as a part of the final PSD permit.

We appreciate the opportunity to comment on the draft PSD permit, and we look forward to reviewing DENR's final permit and to participating in the next phase of the public permitting process. Should you have any questions regarding the enclosed comments, please contact me at (919) 845-1422, extension 20.

Sincerely,

Colin M. Campbell
Project Manager

cc: Preston Phillips, Hyperion

Enclosure A. General Comments

1. On page ii of the draft permit, the facility is described as including an "electric utility" plant. This phrase is potentially confusing, as the facility won't produce electricity for sale. The facility is more accurately described as a petroleum refinery with an "integrated gasification combined cycle power plant."
2. On page 4 of the draft permit, and throughout the permit, the sulfur recovery plant is described as comprising six "lines." The plant is more accurately described as comprising six "trains."
3. On page 5 of the draft permit, the WWTP aeration tanks are described as being equipped with internal floating roofs. This is inconsistent with the information provided in the permit application and is not a technically feasible measure for reducing VOC emissions from the aeration tanks. The WWTP equalization tanks will be configured as internal floating roof tanks.
4. On pages 8-18 of the draft permit, table 1-1 includes 106 references to thermal oxidizers for controlling VOC emissions from storage tanks. As discussed in Enclosure B, these references to the tank farm thermal oxidizers should be deleted entirely.
5. On pages 16-17 of the draft permit, in table 1-1, units #166 through #171 are erroneously described as being equipped with internal floating roofs and venting to control devices #175 or #176. As described in an email from Colin Campbell of RTP Environmental to Kyrik Rombough dated August 27, 2008, VOC emissions from these tanks will be controlled by the vacuum-regenerated, carbon adsorption-based vapor recovery systems serving the railcar and truck loading racks (Units #43 and #44). This equipment configuration will result in greater reductions in VOC emissions as well as reduced emissions of combustion-related pollutants.
6. On page 18 of the draft permit, footnote 4 states that "The thermal oxidizer may or may not be required depending on permit condition 5.11." As discussed in Enclosure B, the reference to these thermal oxidizers should be deleted entirely. In the alternative, if DENR maintains the requirement for using thermal oxidizers for storage tanks pursuant to permit condition 5.11, both thermal oxidizers will be needed. The apparent intent of footnote 4 would be better stated as, "The use of the thermal oxidizer for this tank may or may not be required depending on the compliance option selected under permit condition 5.11."
7. On page 21 of the draft permit, permit condition 3.6.4 would require the facility maintain daily records of the time each combustion turbine burned distillate oil. The required records should also include the quantity of distillate oil burned, on both a daily basis and on a 365-day rolling sum basis. See, also, comments on condition 3.8.10 and condition 5.6.
8. On page 21 of the draft permit, permit condition 3.6.6 would require that the facility collect and analyze samples of wastewater entering the oil/water separators on an hourly basis, analyze each sample for benzene concentration, and calculate a flow-weighted average concentration for each day based on an average of the 24 samples collected. This frequency is excessive and unwarranted; only monthly monitoring is required under 40 CFR § 61.354(b)(1). See, also, comments on condition 3.8.12 and condition 15.2.
9. On page 23 of the draft permit, permit condition 3.8.10 would require that each quarterly report submitted by the facility indicate, for each month in the reporting period, the number of hours that each combustion turbine burned distillate oil on a monthly basis and on a 12-month rolling sum basis. Instead of the number of hours in each month, the report should be required to include the quantity of distillate oil burned, on both a daily basis and on a 365-day rolling sum basis. See, also, comments on condition 3.6.4 and condition 5.6.

10. On page 23 of the draft permit, permit condition 3.8.12 would require that each quarterly report submitted by the facility indicate the flow-weighted average benzene concentration, for each day in the reporting period, based on a 365-day rolling average. This permit condition should be clarified to indicate that it is referring to the benzene concentration of the combined wastewater streams entering each oil/water separator. In addition, this frequency is excessive and unwarranted; rather than daily calculations, only monthly calculations of flow-weighted annual average benzene concentration should be required. See, also, comments on condition 3.6.6 and 15.2.
11. On page 26 of the draft permit, in table 4-1, the PM10 BACT emission limits for each of the sulfur recovery plant thermal oxidizers is stated as 0.0055 pound per long ton of sulfur input. This limit reflects a calculation error by DENR and is incorrect. Section 7.1.1.3 of DENR's Statement of Basis indicates that DENR derived this value by dividing the modeled emission rate of 11.2 pounds per hour by a sulfur recovery plant capacity of 2,040 long tons per hour. The capacity of the sulfur recovery plant is 2,040 long tons per day, and the limit is properly calculated as 0.13 pound per long ton.
12. On page 26 of the draft permit, in table 4-1, the PM10 emission limit for the wastewater treatment plant catalytic oxidizer is stated as 0.01 pound per hour. This limit is not achievable. Section 7.1.1.10 of DENR's Statement of Basis does not indicate the basis for this limit, but it appears that DENR calculated it as the product of an emission factor of 0.0075 pound per million Btu heat input and a heat input rate of 0.8 million Btu per hour. The heat input rate of 0.8 million Btu per hour represents only the auxiliary fuel to the thermal oxidizer; the total heat input rate including wastewater treatment plant vapors is 5.0 million Btu per hour. The achievable PM10 emission rate is 0.05 pound per hour. In addition, this permit term describes the control device as a thermal oxidizer. The device is more accurately described as a catalytic oxidizer, as noted in table 1-1 of the draft permit.
13. On page 27 of the draft permit, in table 4-1, the PM10 emission limits for the coal/coke unloading building, the flux unloading building, and the slag loading building are stated as 2.4 pounds per hour each. This appears to be a transcription error. As presented in appendices C and E to the permit application, the maximum PM10 emissions from these buildings are 0.84 pound per hour from the coal/coke unloading building and 0.42 pound per hour from each of the flux unloading building and the slag loading building.
14. On page 29 of the draft permit, in table 4-1, the PM10 BACT emission limit for each tank farm thermal oxidizer is stated as 0.0075 pound per million Btu heat input. As discussed in Enclosure B, the reference to these thermal oxidizers should be deleted entirely.
15. On page 32 of the draft permit, in table 4-2, the SO_2 BACT emission limits for each of the sulfur recovery plant thermal oxidizers is stated as 0.056 pound per long ton of sulfur input. This limit reflects a calculation error by DENR and is incorrect. Section 7.1.2.3 of DENR's Statement of Basis indicates that DENR derived this value by dividing the modeled emission rate of 114.2 pounds per hour by a sulfur recovery plant capacity of 2,040 long tons per hour. The capacity of the sulfur recovery plant is 2,040 long tons per day, and the limit is properly calculated as 1.3 pounds per long ton.
16. On page 32 of the draft permit, in table 4-2, the SO_2 BACT emission limit for the wastewater treatment plant catalytic oxidizer is a hydrogen sulfide concentration limit of 25 parts per million by volume in the refinery gas. This permit condition should be revised to clarify that vapors from the wastewater treatment plant are not "refinery gas" for the purposes of this permit condition. In addition, this permit term describes the control device as a thermal oxidizer. The device is more accurately described as a catalytic oxidizer, as noted in table 1-1 of the draft permit.

17. On pages 34-35 of the draft permit, in table 4-2, the SO_2 BACT emission limit for each tank farm thermal oxidizer is a hydrogen sulfide concentration limit of 25 parts per million by volume in the refinery gas. As discussed in Enclosure B, the reference to these thermal oxidizers should be deleted entirely. In the alternative, this permit condition should be revised to clarify that vapors from storage tanks are not "refinery gas" for the purposes of this permit condition.
18. On pages 37-40 of the draft permit, in table 4-3, the NO_X emission limit for each combined cycle gas turbine is stated as 10.5 pounds per hour. This appears to be a transcription error. As presented in appendices C and E to the permit application, the maximum NO_X emission rate from each combined cycle gas turbine is 29.8 pounds per hour.
19. On page 40 of the draft permit, in table 4-3, the NO_X BACT emission limit for each tank farm thermal oxidizer is stated as 0.04 pound per million Btu heat input. As discussed in Enclosure B, the reference to these thermal oxidizers should be deleted entirely. In the alternative, this permit condition must be revised because the limit in the draft permit is not achievable. Section 7.1.3.9 of DENR's Statement of Basis indicates that DENR concluded that this limit is achievable and represents BACT based solely on the September 2006 PSD permit for Arizona Clean Fuels Yuma. This facility was never constructed, and the permit expired; the prior existence of this permit limit provides no support for the conclusion that the limit was achievable. The administrative record for the expired Arizona permit similarly includes no information regarding the basis for this emission limit. Based on discussions with vendors, the achievable emission NO_X rates are at least 0.2 pound per million Btu heat input. In addition, the permit condition should be revised to clarify that the heat input is based on the total heat input to the oxidizer, including the heat input from tank vapors and sweep gas as well as auxiliary fuel.
20. On pages 41-42 of the draft permit, in table 4-4, the VOC BACT emission limit for each process heater is stated as 0.0015 pound per million Btu heat input. The limit in the draft permit is not achievable, and it should be revised to reflect a VOC BACT emission limit no more stringent than 0.005 pound per million Btu heat input. Section 7.1.4.1 of DENR's Statement of Basis indicates that DENR reached its conclusion regarding the achievability of the limit in the draft permit based on the limits contained in permits for three purportedly similar facilities in Louisiana and Texas. DENR's conclusions with regard to these facilities are erroneous, as explained below.
    a. Permit PSD-LA-719, issued by Louisiana DEQ on December 27, 2006, for a major expansion of the Marathon Petroleum Company refinery in Garyville, Louisiana. DENR's Statement of Basis indicates that, on page 5 of this permit, the VOC BACT emission limit imposed on process heaters is 0.0015 pound per million Btu heat input. This is incorrect. Page 5 of the cited document is the "briefing sheet" prepared by the Louisiana agency as a summary of the permitting action; it does not contain enforceable conditions. The actual permit conditions are provided on page 22 of the cited document, and there is neither a VOC emission limit nor a requirement to perform any monitoring of VOC emissions from the affected process heaters. Further, the testing requirements for these heaters are set forth on page 65 of the cited document, and there is no requirement for performance testing for VOC emissions. The cited value of 0.0015 pound per million Btu heat input appears to be nothing more than an estimate of the emissions from the heaters at the Marathon refinery. Also, it should be noted that the project covered by the cited permit is currently under construction, so the cited permit documents do not

constitute evidence of the continuous achievability of this emission limit even if it were imposed as an enforceable emission limit.

b. Permit N-007, issued by the Texas agency on September 8, 1998, for a new ethylene manufacturing plant proposed by Fina Oil & Chemical Company. According to DENR's Statement of Basis, "the emission rate for the heaters at this refinery varies between 0.001 to 0.003 pounds per million Btus." This statement is erroneous, and DENR's reliance on this permit as establishing BACT for the refinery fuel gas-fired process heaters at the HEC is misplaced for several reasons. First, the permit pertains to an ethylene manufacturing plant, not a petroleum refinery. The configuration, purpose, and combustion temperatures characteristic of ethylene plant heaters and cracking furnaces are different from those of refinery process heaters. The fuel burned in these heaters and cracking furnaces is different from refinery fuel gas, in particular with respect to the much higher hydrogen content of ethylene cracker process gas. Although these differences in configuration and fuel composition may yield slightly lower VOC emission rates, they also result in markedly higher NO_X emission rates – the NO_X emission limits for the ethylene plant heaters and cracking furnaces in the Fina permit are three to ten times higher than those imposed in the draft permit for the process heaters at the HEC refinery. Second, the Fina permit cited by DENR does not include any enforceable limits on VOC emissions. See, for example, condition 30.B of the Fina permit, which sets forth emission testing requirements, notably omitting any requirement for testing any heater or cracking furnace for VOC emissions. Third, even if the nominal VOC emission rates listed in the Fina permit were enforceable, and they are not, they still would not support the conclusion that an emission factor of 0.0015 pound per million Btu heat input is achievable under all operating conditions, because the nominal emission rates are expressed only as mass emission rate.

c. Permit PSD-TX-302M1, issued by the Texas agency on September 8, 1998, for an expansion of the ethylene manufacturing plant operated by Exxon in Baytown, Texas. According to DENR's Statement of Basis, "the emission rate for the heaters at this refinery varies between 0.0013 to 0.006 pounds per million Btus." This statement is erroneous, and DENR's reliance on this permit as establishing BACT for the refinery fuel gas-fired process heaters at the HEC is misplaced for several reasons. First, the permit pertains to an ethylene manufacturing plant, not a petroleum refinery. The configuration, purpose, and combustion temperatures characteristic of ethylene plant heaters and cracking furnaces are different from those of refinery process heaters. The fuel burned in these heaters and cracking furnaces is different from refinery fuel gas, in particular with respect to the much higher hydrogen content of ethylene cracker process gas. Although these differences in configuration and fuel composition may yield slightly lower VOC emission rates, they also result in markedly higher NO_X emission rates – the NO_X emission limits for the ethylene plant heaters and cracking furnaces in the Exxon permit are three to ten times higher than those imposed in the draft permit for the process heaters at the HEC refinery. Second, the Exxon permit cited by DENR does not include any enforceable limits on VOC emissions. See, for example, condition 16.B of the Exxon permit, which sets forth emission testing requirements, notably omitting any requirement for testing any heater or cracking furnace for VOC emissions. Third, even if the nominal VOC emission rates listed in the Exxon permit were enforceable, and they are not, they still would not support the conclusion that

an emission factor of 0.0015 pound per million Btu heat input is achievable under all operating conditions, because the nominal emission rates are expressed only as mass emission rate.

21. On pages 42-43 of the draft permit, in table 4-4, the VOC BACT emission limit for the wastewater treatment plant catalytic oxidizer is stated as either 98 percent destruction efficiency, or 20 parts per million by weight, whichever is less stringent. The concentration limit should be expressed as 20 parts per million by volume.
22. On page 43 of the draft permit, in table 4-4, the VOC emission limit for each tank farm thermal oxidizer is stated as either 98 percent destruction efficiency, or 20 parts per million by weight, whichever is less stringent. As discussed in Enclosure B, the reference to these thermal oxidizers should be deleted entirely. In the alternative, the concentration limit should be expressed as 20 parts per million by volume.
23. On pages 44-45 of the draft permit, in table 4-5, the CO BACT emission limit for each process heater is stated as 0.007 pound per million Btu heat input. In addition, for each heater, table 4-5 indicates a separate mass emission rate limit that appears to have been calculated using the nominal capacity of the heater in conjunction with an emission factor of 0.007 pound per million Btu heat input. The limits in the draft permit are not achievable, and they should be revised to reflect a CO BACT emission limit no more stringent than 0.01 pound per million Btu heat input as indicated in Hyperion's permit application. Section 7.1.5.1 of DENR's Statement of Basis indicates that DENR reached its conclusion regarding the achievability of the limits in the draft permit based on the limits contained in permits for two purportedly similar facilities in California and Texas. DENR's conclusions with regard to these facilities are erroneous, as explained below.
    a. Permit PSD-TX-302M1, issued by the Texas agency on September 8, 1998, for an expansion of the ethylene manufacturing plant operated by Exxon in Baytown, Texas. According to DENR's Statement of Basis, the allowable CO emission rate for each heater at this facility is 0.009 pound per million Btu heat input. This statement is erroneous, and DENR's reliance on this permit as establishing BACT for the refinery fuel gas-fired process heaters at the HEC is misplaced for several reasons. First, the permit pertains to an ethylene manufacturing plant, not a petroleum refinery. The configuration, purpose, and combustion temperatures characteristic of ethylene plant heaters and cracking furnaces are different from those of refinery process heaters. The fuel burned in these heaters and cracking furnaces is different from refinery fuel gas, in particular with respect to the much higher hydrogen content of ethylene cracker process gas. Although these differences in configuration and fuel composition may yield slightly lower CO emission rates, they also result in markedly higher NO_X emission rates – the NO_X emission limits for the ethylene plant heaters and cracking furnaces in the Exxon permit are three to ten times higher than those imposed in the draft permit for the process heaters at the HEC refinery. Second, the enforceable CO emission rates the Exxon permit cited by DENR are expressed only as mass emission rate limits and do not support the conclusion that an emission factor less than 0.01 pound per million Btu heat input is achievable under all operating conditions. These limits are equal to 0.008 pound per million Btu heat input when the heaters are fired at maximum rated capacity, or 0.011 pound per million Btu heat input when fired at 75 percent of maximum rated capacity. Third, and probably most significantly, the Exxon permit cited by DENR has been superseded. Permit PSD-TX-302M2 was issued by the Texas agency on April 5, 2001. Each of the CO emission limits in the permit cited by DENR has been

increased by a factor of ten, so that these limits are equal to 0.08 pound per million Btu heat input when the heaters are fired at maximum rated capacity and 0.11 pound per million Btu heat input when the heaters are fired at 75 percent of maximum rated capacity.

b. Permit 352869, issued by the South Coast Air Quality Management District on November 17, 2000, for the proposed reactivation of the former Powerine refinery in Santa Fe, California. According to DENR's Statement of Basis, this permit imposes a CO concentration limit of 10 parts per million by volume at 3 percent oxygen, or approximately 0.007 to 0.009 pound per million Btu heat input, on the coker charge heater at this facility. This statement is erroneous, and DENR's reliance on this permit as establishing BACT for the refinery fuel gas-fired process heaters at the HEC is misplaced for several reasons. First, the concentration limit described by DENR is not contained in the cited permit. Second, as noted by DENR in its Statement of Basis, the subject coker charge heater was never installed or operated, and it provides no basis upon which DENR can conclude that an emission limit of 0.007 pound per million Btu heat input is achievable for the refinery fuel gas-fired process heaters at the HEC.

24. On page 47 of the draft permit, in table 4-5, the CO BACT emission limit for each tank farm thermal oxidizer is stated as 0.08 pound per million Btu heat input. As discussed in Enclosure B, the reference to these thermal oxidizers should be deleted entirely.
25. On pages 49-50 of the draft permit, in table 4-1, the H_2S emission limits for each of the sulfur recovery plant thermal oxidizers are stated as 0.3 pound per hour and 0.00015 pound per long ton of sulfur input. The inclusion of two separate limits is redundant and unnecessary, and one of the two limits should be deleted. The 0.3 pound per hour limit was proposed by Hyperion as BACT in its permit application, but Hyperion now considers the alternate form of expression derived by DENR to be more appropriate because it allows for separate compliance demonstrations at each of the thermal oxidizers. If the H_2S BACT emission limit expressed in terms of sulfur input is retained in the permit, then the limit of 0.00015 pound per long ton of sulfur input must be revised. This limit reflects a calculation error by DENR and is incorrect. Section 7.1.7.1 of DENR's Statement of Basis indicates that DENR derived this value by dividing the modeled emission rate of 0.3 pounds per hour by a sulfur recovery plant capacity of 2,040 long tons per hour. The capacity of the sulfur recovery plant is 2,040 long tons per day, and the ratio is properly calculated as 0.004 pound per long ton.
26. On page 50 of the draft permit, in table 4-1, the H_2S emission limits for the acid gas removal system are stated as 3.0 parts per million by volume and 4.2 pounds per hour. The inclusion of two separate limits is redundant and unnecessary, and one of the two limits should be deleted.
27. On page 50 of the draft permit, permit condition 5.2 prohibits the sale of hydrogen, steam or electricity to "an outside entity." Because this term is not defined in the air pollution control regulations and is potentially ambiguous, Hyperion suggests that the prohibition apply to the sale of these commodities "outside the HEC major stationary source."
28. On page 51 of the draft permit, permit condition 5.4 would allow haul roads and parking lots to remain unpaved for one year after initial startup of the refinery. Because the particulate matter dispersion modeling analyses were based on the assumption that all haul roads and parking lots would be paved, this permit condition should be revised to require paving no later than the initial startup of the refinery.

29. On page 51 of the draft permit, permit condition 5.6 would limit each of the five combustion turbines to burning distillate oil no more than 500 hours per year. This requirement is unnecessarily restrictive, and Hyperion requests that the limit instead restrict the quantity of distillate oil burned in each turbine to an amount equivalent to 500 hours of operation at maximum capacity on an annual basis. Hyperion suggests that the limit be phrased as either "shall not operate any of the five combined cycle combustion turbines (Unit #60 through #64) with a heat input from ultra low sulfur distillate oil in excess of 485,500 million Btus per 12-month rolling period" or "shall not operate the five combined cycle combustion turbines (Unit #60 through #64) with a heat input from ultra low sulfur distillate oil in excess of 1,942,000 million Btus per 12-month rolling period, total for all turbines." See, also, comments on condition 3.6.4 and condition 3.8.10.
30. On page 51 of the draft permit, permit condition 5.8 provides that "the owner or operator shall purchase a 2008 model or newer generator and fire pump." To remove ambiguity, Hyperion suggests that this permit condition be revised to provide that "... the owner or operator shall not operate a generator or fire water pump other than a 2008 model year or newer engine."
31. On page 53 of the draft permit, permit condition 5.11 would require the use of closed vent systems and thermal oxidizers to control VOC emissions from storage vessels. For the reasons discussed in Enclosure B, this permit condition should be deleted entirely.
32. On pages 65-67 of the draft permit, permit condition 11.1 would require the use, for each of several combustion sources, of either a continuous emissions monitoring system (CEMS) for exhaust gas SO_2 concentration or a continuous monitoring system for refinery fuel gas H_2S concentration. There are several revisions that should be made to this permit condition.
    a. Permit condition 11.1 would require that each SO_2 CEMS meet the performance specifications in appendix A to 40 CFR part 75 and the quality assurance requirements in appendix B to 40 CFR part 75. This requirement is redundant, unnecessary, and inappropriate. Each of the fuel gas combustion units and sulfur recovery plant thermal oxidizers in table 11-1 is an affected facility under subpart Ja of 40 CFR part 60, which requires adherence to the performance specifications in appendix B to 40 CFR part 60 and the quality assurance requirements in appendix F to 40 CFR part 60 for each monitoring device. The reference to part 75 monitoring system requirements for all units subject to subpart Ja should be replaced with references to part 60 monitoring system requirements.
    b. Table 11-1 indicates that the wastewater treatment plant catalytic oxidizer is subject to the monitoring requirements in permit condition 11.1. The permit condition should be revised to clarify that vapors from the wastewater treatment plant are not are not "fuel gas" for the purposes of this permit condition. In addition, table 11-1 describes this control device as a thermal oxidizer. The device is more accurately described as a catalytic oxidizer, as noted in table 1-1 of the draft permit.
    c. Table 11-1 indicates the tank farm thermal oxidizers are subject to the monitoring requirements in permit condition 11.1. As discussed in Enclosure B, the reference to these thermal oxidizers should be deleted entirely. In the alternative, the permit condition should be revised to clarify that vapors from storage tanks are not "fuel gas" for the purposes of this permit condition.
    d. Table 11-1 of this permit condition indicates that a hydrogen sulfide CEMS is required for the power island acid gas removal system. This is inconsistent with the text of permit condition 11.1, which provides only for a continuous monitoring system for "total sulfur in the fuel gas being burned." Hyperion suggests that the

power island acid gas removal system CEMS requirement be deleted from permit condition 11.1 and be moved to a new permit condition 11.4. Hyperion further suggests that the new permit condition for the power island acid gas removal system CEMS requirement clarify that the monitored stream is an exhaust gas stream, not a fuel stream; that the monitored pollutant is H_2S, not total sulfur; and that the applicable performance specifications are those in appendix B to 40 CFR part 60.

33. On pages 67-68 of the draft permit, permit condition 11.2 would require the use of a NO_X CEMS for several fuel gas combustion units and would require that each CEMS meet the performance specifications in appendix A to 40 CFR part 75 and the quality assurance requirements in appendix B to 40 CFR part 75. This requirement is redundant, unnecessary, and inappropriate. Each of the fuel gas combustion units in table 11-2 is an affected facility under subpart Ja of 40 CFR part 60, which requires adherence to the performance specifications in appendix B to 40 CFR part 60 and the quality assurance requirements in appendix F to 40 CFR part 60 for each monitoring device. The reference to part 75 monitoring system requirements for all units subject to subpart Ja should be replaced with references to part 60 monitoring system requirements.
34. On page 73 of the draft permit, permit condition 13.1 would require that flaring of gases from the refinery be completed in accordance with a flare minimization plan. This requirement is redundant with permit condition 12.1, and appears to be the result of a transcription error by DENR. Permit condition 13.1 should be revised to refer to flaring of gases from the gasification system rather than gases from the refinery.
35. On page 74 of the draft permit, paragraph 18.a of permit condition 13.1 would require a periodic review of flaring that has occurred during planned major maintenance of the gasification system, including flaring during associated startup events, and a periodic evaluation of the feasibility of performing these activities without flaring. Similarly, paragraph 18.b of permit condition 13.1 would require a periodic review of flaring that is expected to occur "due to issues of gas quantity and quality" and a periodic evaluation of the feasibility of "reducing flaring through the recovery, treatment, and use of the gas or other means." The final paragraph of permit condition 13.1 would require that the flare minimization plan be revised as necessary to ensure that the plan complies with these requirements. These permit conditions must be revised to clarify that the flare events described in Table 5.2-5 of Hyperion's PSD permit application are not subject to any requirements for implementing measures for reducing flaring below the levels described in the permit application. Hyperion's permit application demonstrates that there are no technically feasible control measures for eliminating or further reducing emissions from initial start, hot restart, warm restart, or cold restart events, and DENR's BACT determination provides for occurrence of flaring during these events. Hyperion cannot be subjected to a requirement for arbitrary, future re-evaluation of BACT requirements after designing and constructing the gasification system.
36. Chapter 13.0 of the draft permit does not include any restrictions on the sulfur content of off-specification syngas to be burned in the gasification flare. As described in Section 4.13.2 of the permit application, Hyperion has committed to flaring only off-specification syngas that has been desulfurized to a sulfur concentration of 40 parts per million by volume, based on an hourly average, beginning six months after startup of the IGCC power plant. Hyperion requests that this commitment be reflected in the permit as an enforceable emission limit representing BACT for SO_2 emissions from the gasification flare.
37. On page 84 of the draft permit, permit condition 14.13 would require successful repair of a leaking heat exchanger within seven days after detection, with no provision for delay of

repair in the event that a process unit shutdown would be required or in the event of unavailability of parts necessary for repair. Section 7.1.4.8 of DENR's Statement of Basis indicates that its BACT determination for VOC emissions from the cooling water system is based on the work practices imposed in the expired PSD permit for the Arizona Clean Fuels Yuma refinery, but permit condition 14.13 in the draft permit does not provide for the delay of repair provisions that are provided in the Arizona permit, and DENR's Statement of Basis does not provide any basis for omitting any delay of repair provisions. Hyperion requests that the delay of repair provisions from the proposed revisions to subpart CC of 40 CFR part 63, published in the Federal Register on September 4, 2007, be included in permit condition 14.13.

38. On page 84 of the draft permit, permit condition 15.2 would restrict the flow-weighted average benzene concentration in the wastewater entering the oil/water separators to 10 parts per million by weight "determined on a 365-day rolling average." Pursuant to 40 CFR §§ 61.343(c)(2) and 61.348(a)(1)(i), the correct expression for this limit is "on a flow-weighted annual average basis." See, also, comments on condition 3.6.6 and condition 3.8.12. The applicable regulatory requirements do not provide for a daily rolling average.
39. On page 86 of the draft permit, permit condition 16.7 includes an erroneous reference to permit condition 16.7. This appears to be a typographical error, and should be corrected to refer to permit condition 16.8.

Enclosure B. DENR's Proposed BACT Determination for VOC Emissions from Storage Vessels is Unsupported

As noted in Enclosure A, permit condition 5.11 in the draft permit would require the use of closed vent systems and thermal oxidizers to control VOC emissions from most of the organic liquid storage tanks at the HEC. This is inconsistent with the equipment configuration proposed by Hyperion as BACT for VOC emissions from the storage tanks. In Section 4.7.1 of the PSD permit application, and in supplemental information submitted to DENR in response to questions regarding the data underlying Hyperion's proposed BACT determination, Hyperion demonstrated that the use of closed vent systems and thermal oxidizers would result in unacceptable, adverse economic and environmental impacts.

According to Section 7.1.4.11 of the Statement of Basis, DENR disagreed with Hyperion's proposed conclusions, determined the use of closed vent systems and thermal oxidizers is "cost effective," and concluded that this configuration represents BACT for VOC emissions from the storage tanks. As shown in this Enclosure B and in the analysis by Mustang Engineering included as Enclosure C, DENR's conclusion is unsupported, and the equipment configuration proposed in Hyperion's permit application represents BACT for the storage tanks at the HEC.

The proposed equipment configuration would be unprecedented. As discussed below, DENR cites two precedents as bases for its proposed BACT determination, and both are inappropriate. In fact, the proposed equipment configuration is entirely unprecedented; we are unaware of even a single storage tank at any refinery, anywhere, configured in the manner proposed by DENR. In several instances throughout the draft permit and the Statement of Basis, DENR purports to rely on air pollution control technology and emission limit-setting decisions made by other air quality agencies, but here DENR has completely ignored the numerous, informed decisions by other agencies:

- In establishing National Emission Standards for Hazardous Air Pollutants for new sources, such as storage tanks at a new refinery, U.S. EPA is required by § 112(d) of the Clean Air Act to meet prescriptive criteria regarding stringency. Specifically, § 112(d)(2) requires that the established standard "shall require the maximum degree of reduction in emissions [] that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable...." In addition, § 112(d)(3) requires that the established standard "shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator." These criteria are more prescriptive than those associated with BACT and should always result in a control technology determination at least as stringent as BACT. Nonetheless, the U.S. EPA has established new source standards under § 112(d) for numerous categories of stationary sources that include organic liquid storage vessels, including petroleum refineries, and to our knowledge has never even identified the equipment configuration proposed by DENR as an available control option. See, for example, EPA Docket Number EPA-HQ-OAR-2003-0146.
- In ozone nonattainment areas, the applicable statutory requirement for air pollution control requirements is Lowest Achievable Emission Rate ("LAER") rather than BACT. Determinations of LAER, too, are required to meet prescriptive criteria that should always result in determinations that are at least as stringent as BACT determinations. Nonetheless, numerous permitting authorities have issued permits for tanks storing

gasoline and similar materials, at refineries and other types of stationary sources, establishing LAER based on configurations equal to or less stringent than the configuration proposed by Hyperion.

- For example, in September 2008, the San Joaquin Valley Air Pollution Control District issued a draft permit for a major expansion of the Big West refinery in Bakersfield, California. This refinery is one of only a handful of refineries in the United States located in an area designated as serious nonattainment with respect to the National Ambient Air Quality Standard for ozone. The permit authorizes construction of two new gasoline storage tanks, each with a capacity of 80,000 barrels. The permit requires as LAER only that these tanks be equipped with an external floating roof, which is a substantially less effective control measure than an internal floating roof as proposed by Hyperion. See, draft permit S-33-424-0, issued September 3, 2008.
- As another example, in July 2008, the Texas Commission on Environmental Quality issued a final permit for a major expansion of the Valero refinery in Port Arthur, Texas. The permit authorizes construction of two new gasoline storage tanks, each with a capacity of 200,000 barrels, and a new naphtha storage tank with a capacity of 150,000 barrels. The permit requires as LAER only that the gasoline tanks be equipped with internal floating roofs and that the naphtha tank be equipped with an external floating roof. See, Nonattainment NSR Permit N65, issued July 24, 2008.

DENR's reliance on the expired permit for Arizona Clean Fuels Yuma is not appropriate. According to Section 7.1.4.11 of the Statement of Basis, part of the basis for DENR's conclusion regarding BACT for VOC emissions from storage tanks at the HEC is a similar requirement in the September 2006 PSD permit issued to Arizona Clean Fuels Yuma for a new refinery in Arizona. (It should be noted that the September 2006 permit was simply a renewal of the final PSD permit issued in April 2005. The Arizona agency's BACT determination was made in 2005 and was affirmed at the time of the 2006 permit renewal.) Construction of this facility never began, and the permit expired in March 2008. This proposed facility currently has no authorization to construct or operate. The mere issuance of a (now-expired) permit by another state agency does not create a precedent for similar facilities; in fact, as discussed above, the proposed requirement would be entirely unprecedented.

DENR's reliance on Santa Barbara Air Pollution Control District Rule 325 is incorrect. According to Section 7.1.4.11 of the Statement of Basis, part of the basis for DENR's conclusion regarding BACT for VOC emissions from storage tanks at the HEC is a requirement in Rule 325 of the Santa Barbara Air Pollution Control District. Specifically, DENR's Statement of Basis indicates that this rule would apply to the storage tanks at an oil refinery and would require the use of a vapor recovery system that would obtain 90 percent removal efficiency. This statement is incorrect with regard to applicability – Rule 325 expressly applies only to storage tanks "used in the production, gathering, storage, processing, and separation of crude oil and natural gas prior to custody transfer." (Emphasis added.) The rule that would apply to storage tanks at a refinery in Santa Barbara County, if one existed, would be Rule 326. The substantive requirements of this rule are similar to those of Rule 325 – for a tank meeting certain criteria with respect to size and vapor pressure, such as those at the HEC, any of four compliance options may be used. These control options include an external floating roof, an internal

floating roof, a closed-vent system vented to a control device achieving at least 95 percent removal efficiency, or any other vapor loss control device with an efficiency of at least 95 percent. There is no requirement for using two of these control options (e.g., an internal floating roof and a closed-vent system vented to a control device) in combination. The equipment configuration proposed by Hyperion would easily satisfy the requirements of this rule.

It is inappropriate for DENR to rely on the cost effectiveness of the floating roofs that Hyperion has proposed to install voluntarily as a "baseline" for additional controls. In response to questions from DENR during the permit application review process, Hyperion provided cost information and estimates of actual emissions, both in the proposed internal floating roof configuration and in a hypothetical fixed roof tank configuration, for 33 storage tanks at the HEC. All of these tanks are intended to serve primarily in storage of non-volatile materials; however, as noted by DENR in Section 7.1.4.11 of the Statement of Basis, Hyperion has proposed to configure each tank with an internal floating roof in order to maximize the operating flexibility of the refinery. The supplemental data provided by Hyperion indicated the total cost of the internal floating roofs is $36 million and, assuming each tank stores only the material that is nominally the intended material for each tank, the VOC emissions controlled by these internal floating roofs is 194 tons per year. Based on these data, DENR calculated an "annualized cost" of $20,649 per ton of VOC emissions reduction. DENR then makes the following statement:

> With the request for operational flexibility for the storage tanks, Hyperion has established a baseline for what would be considered cost effective for reducing volatile organic compound emission in the tank farm at approximately $20,000 per ton.

As discussed below, DENR subsequently made its own calculations of cost effectiveness of adding closed-vent systems and thermal oxidizers to the storage vessels and determined these additional controls are "cost effective" because they are no more costly than the floating roofs that Hyperion proposed to install voluntarily.

DENR is correct that some of the emission reduction measures proposed by Hyperion would appear to come at a high cost. However, for several reasons, we vigorously disagree with this rationale as the basis for requiring additional controls, as DENR's proposed BACT determination would do. First, and most straightforwardly, DENR's apparent approach would create an unwanted disincentive for pollution prevention: If DENR's policy requires that any costs for voluntary pollution prevention measures must be matched by equally costly and involuntary air pollution control requirements, Hyperion could probably find a way to design the refinery in a way that would eliminate these voluntary pollution prevention measures. Second, DENR's approach focuses only on cost effectiveness and ignores the fact that the control options being evaluated have drastically different impacts other than economic: The floating roofs proposed by Hyperion are pollution prevention measures that will use no energy and will not result in any additional air pollution; whereas the thermal oxidizer configuration proposed by DENR will increase emissions of all regulated pollutants due to combustion. Third, DENR's approach ignores the product loss savings associated with the proposed internal floating roof configuration: The projected emission reduction of 194 tons per year represents an avoided loss of more than 50,000 gallons of valuable refined product annually. Assuming a nominal value of $3.00 per gallon, this represents a savings of more than $150,000 per year. Fourth,

and most significantly, DENR's approach completely ignores the economic value of increased operating flexibility: In preparing the permit application and proposing controls as BACT, Hyperion and RTP recognized that certain assumptions made today with regard to operating scenarios may not hold true for the life of the refinery. Hyperion and RTP also recognized that, if a fixed-roof configuration were proposed for any tank based on the low volatility of the materials to be stored in that tank, then the PSD permit would likely contain enforceable restrictions on the stored materials. The operating costs of such a restriction can be tremendous; depending on upgrading margins, shutting down a processing unit at a 400,000 barrel-per-day refinery because no suitably equipped tanks are available to store the products of that unit can easily result in lost opportunity costing hundreds of thousands of dollars per day. These costs can be avoided by installing state-of-the-art controls in each tank and maximizing operating flexibility. Emission reductions achieved by these controls are, from the refinery's standpoint, incidental.

DENR's estimates of the costs of closed-vent systems and thermal oxidizers are not representative. In Section 4.7.1 of the PSD permit application and in supplemental information submitted to DENR during its review of the permit application, Hyperion submitted data characterizing the costs of equipping various combinations of storage tanks with closed-vent systems and thermal oxidizers. Each of these submittals demonstrated the use of these controls would result in unacceptable, adverse economic and environmental impacts. According to Section 7.1.4.11 of the Statement of Basis, DENR based its proposed BACT determination for the storage tanks at the HEC on its own cost estimates. DENR's cost estimates were apparently based on information developed for surface coating operations and other types of facilities and on general information in a report produced by U.S. EPA in September 2000. As explained in detail below and by the data provided in Enclosure C, DENR's cost estimates are not representative of current costs of installation and operation of these controls in a petroleum refinery.

Permit condition 5.11 in the draft permit allows for excluding several tanks from the thermal oxidizer requirement, provided that those tanks use internal floating roofs and store only material with low vapor pressure. Section 7.1.4.11 of the Statement of Basis indicates that this provision reflects DENR's conclusion that tanks meeting these criteria are not cost-effectively controlled. There are a total of 66 storage tanks that are covered by the thermal oxidizer requirement and are not eligible for the exclusion in draft permit condition 5.11, comprising 47 tanks in the west tank farm and 19 tanks in the south tank farm. This is a collection of tanks that is different from any of the various combinations that Hyperion has previously evaluated, including in the analysis requested by DENR during its review of the permit application. The revised economic impacts analysis discussed herein pertains to these 66 tanks. This analysis differs from the information Hyperion and RTP have provided to DENR previously in several respects – it reflects addition of the tanks storing very heavy materials such as vacuum residuum and vacuum gas oil, the engineering of the necessary closed-vent systems has progressed further, and Mustang Engineering obtained cost estimates from a vendor of thermal and catalytic oxidation systems in order to refine its estimate of total installed costs for the complete system. The vendor recommended energy-efficient recuperative systems, including a catalytic oxidizer for the south tank farm and a thermal oxidizer for the west tank farm. Based on these cost estimates, the cost effectiveness of the proposed control requirement is more than $25,000 per ton of VOC emission reduction, as shown in Table B-1.

Table B-1. Cost Effectiveness of Closed-Vent Systems and Incinerators for Control of VOC Emissions from Storage Vessels

PARAMETER		South	West	Total
Flow rate	ACFM	1,316	2,274	3,590
VOC in	tpy	28.1	114.5	142.6
VOC control efficiency	%	98.0	98.0	98.0
VOC out	tpy	0.6	2.3	2.9
VOC reduction	tpy	27.5	112.3	139.8
Natural gas in	MMBtu/yr	1,664	65,131	66,795
Capital cost	$	$ 3,700,000	$ 19,819,000	$ 23,519,000
Annualized capital cost	$/yr	$ 406,240	$ 2,176,020	$ 2,582,260
NG cost	$/yr	$ 21,637	$ 846,698	$ 868,335
Electricity cost	$/yr	$ 6,859	$ 11,432	$ 18,291
Total annual cost	$/yr	$ 434,736	$ 3,034,149	$ 3,468,886
Cost effectiveness (VOC only)	$/ton	$ 15,787	$ 27,029	$ 24,814
NO_X emissions	tpy	0.2	6.5	6.7
Cost effectiveness (VOC and NO_X)	$/ton	$ 15,883	$ 28,693	$ 26,059

The drastic differences between the cost effectiveness values shown above and those calculated by DENR are attributable to several factors:

- The very long runs of piping in going from a plot the size of a large refinery increases the need for additional vapor/liquid separation protection for the incinerator. Mustang's cost estimate includes liquid knock out drums and pumps, installed below grade in a sump, to minimize operability problems in the oxidizers.
- For the tanks storing very heavy liquids, such as vacuum residuum and vacuum gas oil, heat tracing is required in order to prevent the material from solidifying in the vent gas lines. This cost element was not reflected in Hyperion's initial permit application, and it appears not to have been reflected in DENR's cost estimate, but it is included in Mustang's cost estimate.
- The west tank farm includes tanks serving tanks storing both sweet and sour materials, including materials that cannot be exposed to oxygen. Natural gas is required as sweep gas in order to prevent oxygen exposure and cross-contamination. This cost element was not reflected in Hyperion's initial permit application, and it appears not to have been reflected in DENR's cost estimate, but it is included in Mustang's cost estimate.
- The safety requirements in a refinery, and the corresponding requirements for instrumentation and other equipment, are greater than in other types of facilities.
- The environmental requirements in a refinery exceed those in other types of facilities. In particular, for the closed-vent systems that would be required by the draft permit, condensate drains will be required, and the material collected in these drains will contain benzene, which triggers extensive and prescriptive requirements not applicable to the other types of facilities reviewed by DENR.
- Commodity costs have escalated significantly over the past several years, and DENR's cost estimates appear not to have reflected current costs.

Enclosure C

Cost Estimate from Mustang Engineers & Constructors, LP for Tank Farm Closed-Vent Systems and Thermal/Catalytic Oxidizers

REVISION NO. 1
Estimate No. 2
CLIENT: Hyperion
LOCATION: Elk Point, SD
PLANT: Hyperion Energy Center
JOB NO.: 14912
DATE: October 22, 2008

Tank Farm Vapor Oxidation system

Basis Of Estimate

The estimate is broken down into two components:

- The tank farm recovery incineration unit.
- Piping, Instrumentation, and electrical to recover vapor from the tanks

The two sections were estimated with two different methods. What follows will be a short discussion of the method for each section:

Vapor Oxidation

Order of magnitude estimate for refinery facilities are normally done by a factor method that uses a cost for major tagged equipment as a basis for the factor.
Costs are added to the base equipment cost using a factor to account for the associated commodities required for the facility. These factored estimates are developed in three steps:

1. The major equipment cost for this estimate was developed from informal pricing from a typical equipment supplier. The block flow diagram on the oxidizer specification shows the extent of the oxidizer package. Additionally we have added additional equipment that will be required to control condensate drainage in the vent gas lines.

2. An estimate such as this can be generated using an overall cost factor, but the factor is generally composed of the following cost elements and the percentage normally obtained from completed projects. The factor is deemed relevant to an installation in a simple process unit area such as the oxidizer unit.

a.	Major Equipment	30%
b.	Commodity Material and Construction Cost	50%
c.	Engineering	15%
d.	Client Cost.	5%
e.	Total	100%

3. The overall cost factor as a multiplier on major equipment, that results from this type of breakdown is 100/30 = 3.33.

In a refinery, the largest single component of the cost is the commodity cost. This is broken down in the following components:

1. Piping	20%	
2. Concrete/ Sewers and Structural	15%	
3. Instrument Electrical	10%	
4. Insulation Paint and Other	5%	
5. Total		50%

- These items are required because the Oxidation Unit installation will require foundations, fluid and gas services, sewer services, electrical services, and associated instrument controls located remotely from the Oxidation Unit. In a refinery, all equipment and piping

must be built to standardized codes typical to refinery construction (such as API) and must conform to electrical classification standards for hazardous areas. Conformance to these codes usually results in installed costs that tend to be higher than commercial of chemical type installations

- One of the largest components of the commodity cost is piping. This piping is the utility feeds and support to operate the oxidizers. These services will be incremental additions to the normal refinery utilities. Services such as fuel gas, air, utility water services for the area, and sewer drain systems will be required to support the oxidizer units. These items are shown diagrammatically on the simplified block flow on the Oxidizer specification sheets. Such piping services will be required to support the condensate control sump equipment as well.

  The final routing and lengths of the services are not defined as of yet so they are included in the factor for installation. In the case of the south tank farm the piping run lengths for these is not definitively determined but will be considerable because of the distance from the sources in the main process areas.

Tank Piping / Instrument and Electrical

This section of the estimate includes all commodities that are outside of the process area for the oxidizers. This estimate is developed by use a quantity based estimate. A plot plan was used to estimate linear footage of piping for the recovery. The block flow diagram included with the oxidizer specification was used as a basis for the required pipeline services.

Piping systems included the following services:

- Vapor vent lines in the west tank farm are routed from each applicable tank to the incinerator unit for the west tank farm. The unit will be located in the process unit area as refinery spacing guidelines will dictate that it be located at a minimum 300 ft. distance from the tankage.
- The vapor vent lines in the south tank farm will be routed to the incinerator located in an isolated area near the loading facilities.
- A gas blanketing line for the Heavy Coker Gas Oil service tanks. This provides constant pressure from these tanks.
- Air pressuring lines for each of the major headers (2 in the west tank farm, 1 in the south tank farm). These lines will provide compensation gas pressure when other tank volumes are lowered due to reduced inventories.
- Heat tracing on the heavy vapor header is required to prevent precipitation of heavy liquids in the vapor lines and a resulting blockage of flow. This system is usually implemented with electrically heated wiring attached to the pipe lines.

The Cost of the piping is the extension of footage of the piping takeoff times a unit cost that is all inclusive of piping construction cost (excluding client cost).

The unit cost is the all-in installed cost per linear foot of piping

The cost basis is third quarter 2008

MUSTANG ENGINEERS & CONSTRUCTORS, L.P.	OXIDIZER DATA SHEET	REV.	DATE	DESCRIPTION	APPV.	SHEET 1 OF 2
		A	JMM	For Inquiry		SPEC. NO.:
						REV. NO.:
CLIENT: Hyperion						PROJ. NO.: 14192
PROJECT: Grass Roots Refinery						BY: JMM
LOCATION: South Dakota						DATE: Oct-01-08

NOTE: APPLICABLE TO INQUIRY (X) PURCHASE ( ) AS BUILT ( )

Service: West Tank Farm Oxidizer(s) **Item No.:** Z-1001

Description:

A grassroots refinery is obtaining an air permit and is performing emission reduction studies to determine the cost effectiveness of emission abatement options.

One option under study, and potentially required by the permitting authorities, is to collect the tank farm working/breathing losses and combust those vents in an oxidizer device. In this option, the West tank farm will have three independent vent collection headers to minimize tank cross contamination issues. The tank vapors in these three vent collection headers must be combusted in either a single device which ensures no interchange between the headers or in independent devices. The oxidizer vendor is requested to propose the system design which ensures no interchange between headers but which also sensibly minimizes duplication of equipment.

The three feed streams will enter the oxider(s) in segregated piping. The feed streams are composed of a mixture of air, methane and a small amount of tank contents. The exact composition of the tank contents is not known at this time, but the vendor may consider them to be hydrocarbons. The MW of the tank contents is given. Also a heat of combustion of the tank contents is approximated and listed on this data sheet.

		Feed 1	Feed 2	Feed 3
Feed Description		West Light Sour	West Light Sweet	West Heavy
Air Rate (MW = 29)	lb/hr	2,908	5,161	1,269
Methane Rate (MW = 16)	lb/hr	0	0	278
Tank Vapors Rate	lb/hr	11.0	5.5	33.2
Tank Vapors Molecular weight	lb/lbmole	54	77	130
Tank Vapors Heat of Comb	btu/lb	19,677	19,468	19,267
Total Feed Rate	ACFM	672	1,191	411

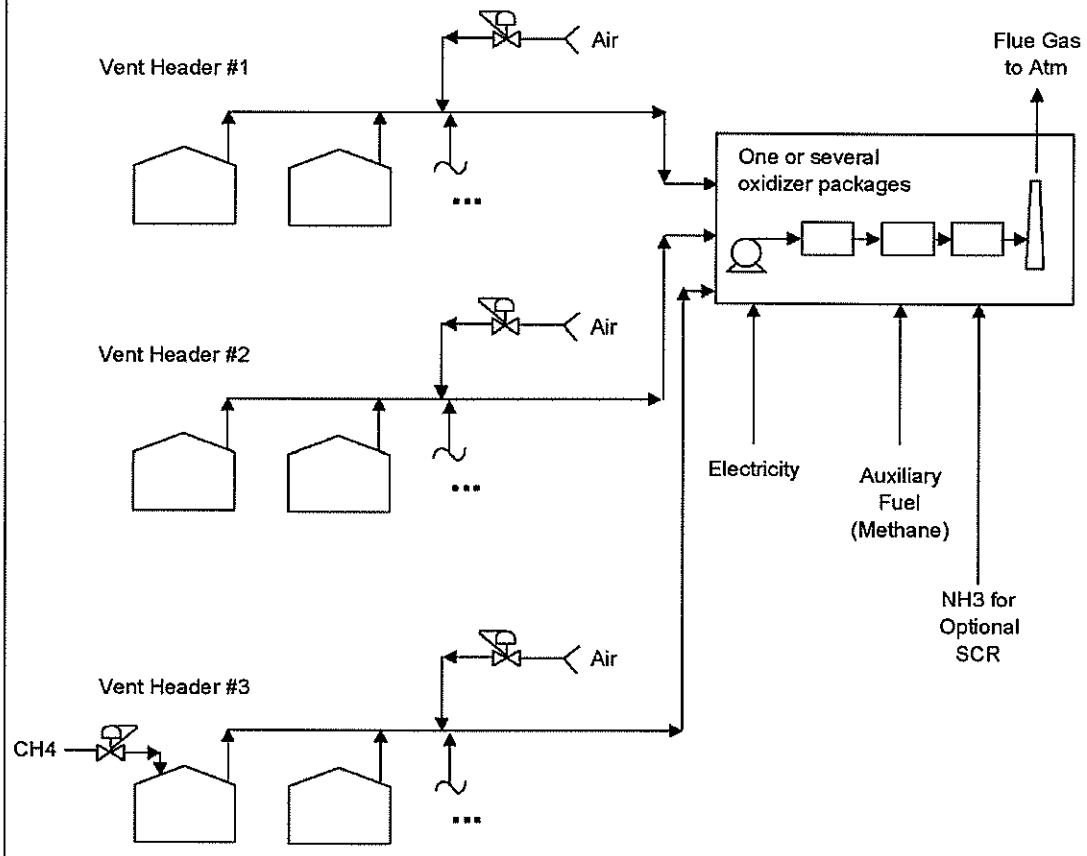
1) Destruction efficiency to be 98% minimum.
2) Vendor to report auxiliary fuel gas rate.
3) Vendor to report emission rates of NOx emission rates in terms of overall heat release or burner heat release.
4) Vendor to include options with and without SCR to indicate NOx reduction possible with SCR.
   Vendor to provide the NH3 injection rate for the SCR option.
5) Vendor to indicate scope of package including type of oxidizer chosen as well as any support equipment required which is not part of the vendor package
6) Feed to the oxidizer is to be considered to vary between 0 °F and 100°F at 0.1 psig.
7) Vendor to assume auxiliary fuel is methane.
8) If single oxidizer proposed, vendor to indicate how cross header contamination is to be avoided.

MUSTANG ENGINEERS & CONSTRUCTORS, L.P.	OXIDIZER DATA SHEET	REV.	DATE	DESCRIPTION	APPV.	SHEET 2 OF 2
		A	JMM	For Inquiry		SPEC. NO.:
						REV. NO.:
CLIENT: Hyperion						PROJ. NO. 14192
PROJECT: Grass Roots Refinery						BY: JMM
LOCATION: South Dakota						DATE: Oct-01-08

NOTE: APPLICABLE TO INQUIRY (X) PURCHASE ( ) AS BUILT ( )

Service: West Tank Farm Oxidizer(s) **Item No.:** Z-1001

System Sketch



MUSTANG ENGINEERS & CONSTRUCTORS, L.P.	OXIDIZER DATA SHEET	REV.	DATE	DESCRIPTION	APPV.	SHEET 1 OF 2
		A	JMM	For Inquiry		SPEC. NO.:
						REV. NO.:
CLIENT: Hyperion						PROJ. NO.: 14192
PROJECT: Grass Roots Refinery						BY: JMM
LOCATION: South Dakota						DATE: Oct-01-08

NOTE: APPLICABLE TO INQUIRY (X) PURCHASE ( ) AS BUILT ( )

Service: South Tank Farm Oxidizer **Item No.:** Z-1002

Description:

A grassroots refinery is obtaining an air permit and is performing emission reduction studies to determine the cost effectiveness of emission abatement options.

One option under study, and potentially required by the permitting authorities, is to collect the tank farm working/breathing losses and combust those vents in an oxidizer device. In this option, the South tank farm will have a single vent collection header.

The feed stream is composed of a mixture of air, methane and a small amount of tank contents. The exact composition of the tank contents is not known at this time, but the vendor may consider them to be hydrocarbons. The MW of the tank contents is given. Also a heat of combustion of the tank contents is approximated and listed on this data sheet.

		Feed 1
Feed Description		South Light Sweet
Air Rate (MW = 29)	lb/hr	5,700
Methane Rate (MW = 16)	lb/hr	0
Tank Vapors Rate	lb/hr	7.1
Tank Vapors Molecular weight	lb/lbmole	68
Tank Vapors Heat of Comb	btu/lb	15,688
Total Feed Rate	ACFM	1,316

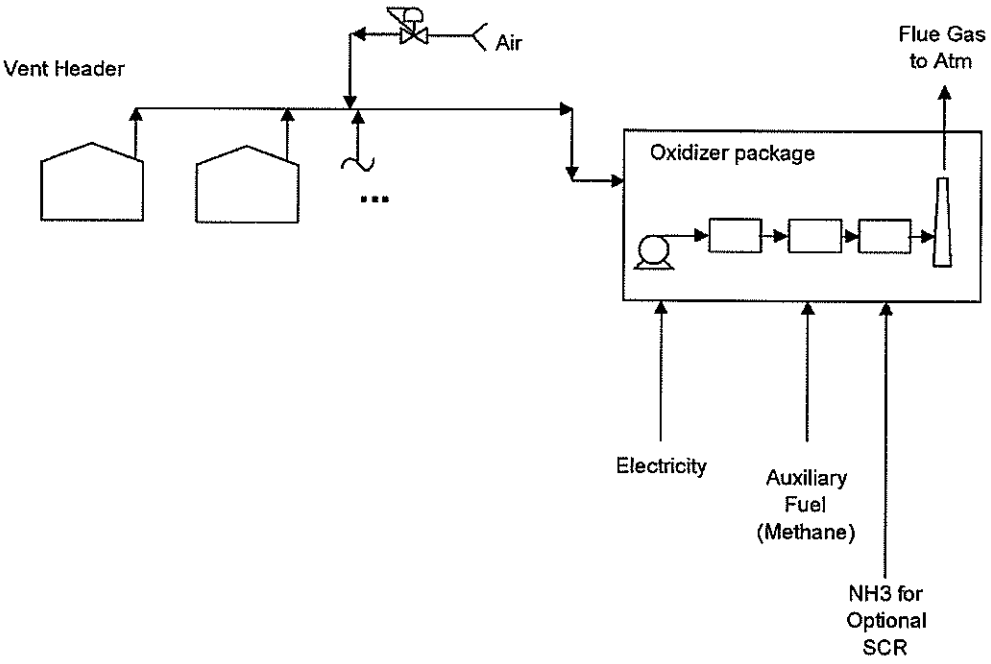
1) Destruction efficiency to be 98% minimum.
2) Vendor to report auxiliary fuel gas rate.
3) Vendor to report emission rates of NOx emission rates in terms of overall heat release or burner heat release.
4) Vendor to include options with and without SCR to indicate NOx reduction possible with SCR.
   Vendor to provide the NH3 injection rate for the SCR option.
5) Vendor to indicate scope of package including type of oxidizer chosen as well as any support equipment required which is not part of the vendor package.
6) Feed to the oxidizer is to be considered to vary between 0 °F and 100°F at 0.1 psig.
7) Vendor to assume auxiliary fuel is methane.

MUSTANG ENGINEERS & CONSTRUCTORS, L.P.	OXIDIZER DATA SHEET	REV.	DATE	DESCRIPTION	APPV.	SHEET 2 OF 2
		A	JMM	For Inquiry		SPEC. NO.:
						REV. NO.:
CLIENT: Hyperion						PROJ. NO. 14192
PROJECT: Grass Roots Refinery						BY: JMM
LOCATION: South Dakota						DATE: Oct-01-08

NOTE: APPLICABLE TO INQUIRY (X) PURCHASE ( ) AS BUILT ( )

Service: South Tank Farm Oxidizer **Item No.:** Z-1002

System Sketch



MUSTANG ENGINEERS & CONSTRUCTORS, LP.

PAGE 1 OF 1
EST. BY: MDA

REVISION NO. 1
Estimate No. 2A
CLIENT: Hyperion
LOCATION: Elk Point, SD
PLANT: Hyperion Energy Center
JOB NO.: 14912
DATE: October 2008

CONFIDENTIAL PROJECT SUMMARY
DO NOT REPRODUCE-INHOUSE COPY ONLY
Rough Order of Magnitude Estimate
ACCURACY RANGE: +/- 50%

Case 3 Tank Farm Oxidizers

26-Oct-08
7:47 PM

	DIRECT COST	TA HOURS	PTA HOURS	LABOR DOLLARS	MATL DOLLARS	S/C DOLLARS	TOTALS
1	OXIDATION SYSTEM				$4,422,000		$4,422,000
2	SITEWORK						
3	EARTHWORK						
4	PILING						
5	CONCRETE						
6	STRUCT. STEEL						
7	BUILDINGS						
8	ABOVEGROUND PIPE				$17,097,000		$17,097,000
9	UNDERGROUND PIPE						
10	INSTRUMENTS				$1,000,000		$1,000,000
11	ELECTRICAL				$1,000,000		$1,000,000
12	INSULATION						
13	PAINTING						
14	FIREPROOFING						
15	DEMOLITION						
16	SUPPORT WORK						
17	TOTAL DIRECTS				$23,519,000		$23,519,000
18	INDIRECT MATL/LBR/S/C						
19	INDIRECT LABOR / TRAVEL & SUB						
20	FIELD STAFF / HOME OFFICE COST						
21	CONSTRUCTION EQUIPMENT						
22	MARKUP & FIXED FEE						
23	TOTAL INDIRECTS						
24	SUBTOTAL (17 & 23)						$23,519,000
25							
26							
27							
28							
29							
30	TOTAL HOME OFFICE						
31	SUBTOTAL (24 & 30)						$23,519,000
32							
33	SALES TAX						
34	ESCALATION						
35							
36	CONTINGENCY						
37							
38							
39							
40							
41	TOTAL INSTALLED COSTS (31 thru 38)						$23,519,000
42							
43	CLIENT COSTS 5%						$1,000,000
44							
45	TOTAL JOB COSTS						$24,519,000

MUSTANG ENGINEERS & CONSTRUCTORS, LP. PAGE 1 OF 1

REVISION NO. 1 — CONFIDENTIAL PROJECT SUMMARY — EST. BY: MDA
Estimate No. 2A — DO NOT REPRODUCE-INHOUSE COPY ONLY
CLIENT: Hyperion — **Rough Order of Magnitude Estimate**
LOCATION: Elk Point, SD — ACCURACY RANGE: +/- 50%
PLANT: Hyperion Energy Center
JOB NO.: 14912 — **Case 3 Tank Farm Oxidizers**
DATE: October 2008 — Equipment Installation — 26-Oct-08 7:47 PM

Item	Cost	Qty				
West Tank Farm Oxidation System						
Oxidizer Package(Quadrant SR-2500)	**300000**	**1**				**$ 300,000**
Sump Drums	150000	3				$ 450,000
Sump Pumps	60000	3				$ 180,000
Sub total						$ 930,000
Installed Cost Factor						3.3
West Tank Farm						$ 3,069,000
South Tank Farm Oxidation System						
Oxidizer Package (Vector CatOx)	**200000**	**1**				**$ 200,000**
Sump Drums	150000	1				$ 150,000
Sump Pumps	60000	1				$ 60,000
						$ 410,000
Installed Cost Factor						3.3
South Tank Farm						$ 1,353,000
Total						**$ 4,422,000**

MUSTANG ENGINEERS & CONSTRUCTORS, LP. PAGE 1 OF 1

REVISION NO. 1 — CONFIDENTIAL PROJECT SUMMARY — EST. BY: MDA
Estimate No. 2A — DO NOT REPRODUCE-INHOUSE COPY ONLY
CLIENT: Hyperion — **Rough Order of Magnitude Estimate**
LOCATION: Elk Point, SD — ACCURACY RANGE: +/- 50%
PLANT: Hyperion Energy Center
JOB NO.: 14912 — **Case 3 Tank Farm Oxidizers**
DATE: October 2008 — Piping Systems — 26-Oct-08 7:47 PM

Item	Count	Qty/Item	Total Qty		Unit Cost	
West Tank Farm						
No. 1 West Light Sour Header	1	12300	12300		390	4,797,000
Branches to Tanks	19	100	1900		280	532,000
Air Line	1	250	250		160	40,000
West Light Sweet Header	1	6300	6300		390	2,457,000
Branches to Tanks	20	100	2000		280	560,000
Air Line	1	250	250		160	40,000
No. 3 West Heavy Header	1	13300	13300		390	5,187,000
Branches to Tanks	8	100	800		280	224,000
Sweep Gas Line on HCGO	1	250	250		160	40,000
Air Line	1	250	250		160	40,000
Heat Tracing Allowance			14100		130	$ 1,833,000
Total West Tank Farm						**$ 15,750,000**
South Tank Farm						
South Tank Farm Header	1	2100	2100		390	819,000
Branches to Tanks	16	100	1600		280	$ 448,000
Air Line	1	500	500		160	$ 80,000
Total South Tank Farm						**$ 1,347,000**
Total						**$ 17,097,000**

West Tank Farm

QUADRANT SR-2500 Thermal Oxidizer

Feed 1 and 2 = 1,900 scfm @ 70 F w/ 17 pph VOC. Sent to Booster fan and to primary heat exchanger.
Feed 3 = 411 scfm @ 70 F w/ 33 pph VOC, sent to dedicated blower and injected into the combustion chamber.
60% primary shell and tube Hx.
Provide 99% removal of VOC
Equipment Cost: ~ $ 300,000
Natural Gas: < 800,000 BTUH (.12 lbs/hr NOx)
15 HP motor, 5 HP motor, 5 HP motor

South Tank Farm

VECTOR 1.5 Catalytic Oxidizer with VOC abatement catalyst

70% primary heat exchanger
Provide 98% removal of VOC
Equipment Cost: ~ $ 200,000
Natural Gas: 190,000 BTUH (.04 lbs/hr NOx)
15 HP motor