

NOTICE

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## THE EFFECT OF OIL SHALE RECOVERY PROCESSES ON AIR EMISSIONS

By

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Development of oil shale production processes has led to a variety of retort designs. Figure 1 shows the total facility emissions as reported in the PSD permit applications for seven potential shale oil recovery plants. The actual facility emissions based on the reported processes, in some cases, would be significantly higher if assumptions made by the developers regarding low levels of organic sulfur and nitrogen species in retort gases prove incorrect. The degree of variation in total facility emissions is considerable with complicating tradeoffs. For example, the Clear Creek facility with a Chevron solids recycle retort has very high  $\text{NO}_x$  and CO emissions. Conversely, the Union facility with a gas recycle retort has much lower CO and  $\text{NO}_x$  emissions but higher  $\text{SO}_x$  emissions.

The purpose of this analysis was to evaluate these various processing schemes and determine the effect of improved air pollution controls. The information presented below will show that, with the proper selection of air pollution control techniques, the air emissions for each of these processes can be held to essentially equivalent values.

In developing the analysis for this process comparison, the EPA's Pollution Control Technical Manuals (PCTMs) for various shale oil processes (References 1, 2, 3) and various PSD Permit Applications (References 4, 5, 6, 7, 8, 9, 10) were used. The PCTMs present a

comprehensive analysis of the heat and material flows in a complete oil shale recovery process. The PSD applications provide controlled air emissions for the specific process considered by the developer. Thus, the comparison presented in this paper is based on the actual design conditions expected in a full-scale operation.

SHALE OIL RECOVERY PLANT

A shale oil recovery plant is quite complex involving many varied operations. The unit operations required to recover the oil from the shale include:

- mining
  - below-ground
  - above-ground
- retorting
- product recovery
- removal of nitrogen (ammonia and organic nitrogen gases) from the retort gas
- removal of sulfur (hydrogen sulfide and organic sulfur gases) from the retort gas
- gas utilization (retort gas combustion)
- end of pipe controls
- upgrading
- spent shale disposal

Within each of these unit operations there can be a number of process alternatives. The shale can be mined in an open pit mine or a room and pillar mine, or the

oil can be recovered without mining with an in-situ process. The retort heat can be provided by combustion of the spent char within the retort or with a recycled stream which can be either gas or solid. Each of these variations can affect the emission rates. Consequently, consideration of all the potential processing schemes can be quite complicated.

Figure 2 presents some possible processing combinations considered as viable alternatives for full scale processing. The specific process combinations used for this analysis are presented in Table 1.

Table 1. FIVE PROCESSES FOR ANALYSIS

Case No.	Mining	Retort
1	Open pit	direct combustion heat <sup>(a)</sup> (e.g., Paraho)
2	Room & pillar	direct combustion heat - circular grate (e.g., Superior, Dravo, Allis Chalmers)
3	Room & pillar	indirect combustion <sup>(b)</sup> gas recycle (e.g., Union)
4	Room & pillar	indirect combustion solids recycle (e.g., Lurgi, Chevron)
5	Modified in-situ	in-situ and indirect heat gas recycle above ground

(a) Direct combustion heat - the heat for retorting is provided by combustion of the spent char within the retort.

(b) Indirect combustion heat - the heat for retorting is provided by combustion of retort gas or spent shale outside of the retort.

In this paper the methodology used to evaluate the various processes will be presented first. Then an evaluation of the sulfur and nitrogen gases produced by the retort for the various processes will be presented along with a discussion of the effect on the acid gas removal processes and net facility emissions. Emissions from other facets of the shale oil recovery operation (e.g., mining, solids handling, spent shale disposal) will then be presented. This is followed by an analysis of the emissions for five typical processes being considered for full scale development.

For each analysis, a base case scenario representative of the process configuration proposed by the developers is presented, and the criteria pollutant emissions are determined. Then two alternative processing schemes to reduce these emissions to their lowest levels are considered.

#### METHODOLOGY

For this analysis, the oil recovery facility was divided into three basic categories: mining, retort, and upgrade. The emissions associated with mining and solids handling (primarily particulates, carbon monoxide, and nitrogen oxides) are similar to other mining operations. The data provided in the PSD permit applications were used to develop emission rates for each

type of unit operations (e.g., blasting, drilling, vehicles, conveying, crushing). The emissions associated with the upgrading process (hydrocarbons from storage and fugitive sources), other than those from the combustion of the retort gas, are similar to other oil refining operations and, again, the PSD permit applications were used to develop estimated emission levels.

The combustion of the retort gas can be the principal source of emissions from the facility and the source most affected by the particular retort process and gas cleanup scheme used.

The primary concern of this analysis is emissions of nitrogen and sulfur oxides and particulates. Emissions of carbon monoxide and hydrocarbons are generally consistent for all processes, with a few exceptions. The combustion of the spent shale can produce very high carbon monoxide emissions, and this will be discussed below for that particular process. High hydrocarbon emission rates can result from certain types of retort processes (e.g., Tosco II) that involve direct contact heating of raw shale or a heat carrier with flue gas. However, this process was not included in this analysis.

To evaluate the many process variations and develop the data necessary to estimate emission levels it was first necessary to determine what process combinations are feasible. The alternatives considered are shown in Figure 1.

The basic design parameters that affect the pollutant emissions for each process were defined. These design parameters are shown in Table 2.

Table 2. DESIGN PARAMETERS USED IN ANALYSIS

Unit Operation	Design Parameter
Mining	Type of Mining open pit room and pillar in-situ
Retort	<ul style="list-style-type: none"> <li>Retort Gas Produced, m<sup>3</sup>/m<sup>3</sup> of oil</li> <li>Heating Value of Retort Gas, kJ/m<sup>3</sup></li> <li>Partitioning of sulfur and nitrogen</li> </ul>
Product recv'ry	None- The product recovery process has no significant effect on emiss.
NH <sub>3</sub> removal	<ul style="list-style-type: none"> <li>NH<sub>3</sub> exit concentration, ppm</li> <li>Organic nitrogen content of retort gas, %</li> </ul>
H <sub>2</sub> S removal	<ul style="list-style-type: none"> <li>H<sub>2</sub>S exit concentration, ppm</li> <li>Organic sulfur content of retort gas, %</li> <li>Organic sulfur gas removal effic., %</li> </ul>
Gas utilization	<ul style="list-style-type: none"> <li>Boiler-dilution ratio (dry gas/fuel)</li> <li>Spent shale combustion exit concentrations for NO<sub>x</sub>, SO<sub>x</sub> &amp; CO, ppm</li> </ul>
End-of-pipe controls	<ul style="list-style-type: none"> <li>Particulate - Baghouse - exit loading, g/m<sup>3</sup></li> <li>Sulfur - FGD - exit SO<sub>x</sub>, ppm</li> <li>Nitrogen</li> <li>Ammonia injection - exit NO<sub>x</sub>, ppm</li> <li>Staged combus. - exit NO<sub>x</sub> &amp; CO, ppm</li> </ul>

For each of the unit operations, the design parameters were applied as indicated by either the retort

process conditions, performance of the pollution control equipment, or the reported emissions from the PSD applications. The following discussion presents the rationale for choosing the specific design parameters used in the analysis.

#### MINING, SOLIDS HANDLING, AND UPGRADING EMISSIONS

The data provided in the PSD permit applications were evaluated to determine typical emission rates for the various unit operations. Figures 3 through 7 show the emission rates from individual sources for the criteria pollutants. For this analysis, all emissions associated with combustion of the retort gas (i.e., upgrade heater, retort heater) are considered as part of the emissions from the retort operation.

The carbon monoxide emission sources (Figure 3) are blasting, below ground vehicles, above ground vehicles, and the combustion of the retort gas in the retort and upgrading process. The hydrocarbon emission sources (Figure 4) are primarily mining vehicles, storage, and fugitive emissions in the upgrading and retort gas combustion. Nitrogen oxide emission sources (Figure 5) are primarily from retort gas combustion and mining vehicles. The only significant sulfur oxide emissions source (Figure 6) is the combustion of the retort gas, with mining and upgrading adding a relatively small amount.

The particulate emission sources (Figure 7) are those associated with below ground mining (drilling, blasting, conveying, crushing, engines), above ground mining (surface soils removal, second and third degree crushing, conveying, storage, and spent shale disposal), retort gas combustion (steam generator, retort heater, and upgrade heaters), above ground vehicles, and fugitive emissions from truck traffic.

The values from the PSD permit applications presented for mining and upgrading emissions were used in the overall facility emission estimates presented below. The emissions from retort gas combustion were calculated as described below.

The choice of mining technique determines the emission rates. The values used were developed from the PSD analysis for room and pillar mining and from the literature for open pit mining (Reference 1). The emission rates used are shown in Table 3.

Table 3. EMISSION RATES FOR MINING  
(Above- and Below-Ground)

Type of Mining	Emissions, kg/1000 m <sup>3</sup> of Oil				
	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Open pit	370	50	470	40	410
Room & pillar	150	20	350	20	180
Room & pillar with catalytic converters on engines	15	2	350	20	180

#### RETORT GAS

The emissions from the combustion of the retort gas are determined by:

- volume and heating value of the retort gas
- presence of sulfur in the gas
- presence of nitrogen as ammonia or organic nitrogen compounds

The retort gas flow rates for three types of retorts are shown in Table 4.

Table 4. RETORT GAS PRODUCTION RATES

Type Retort	Gas Produced m <sup>3</sup> /m <sup>3</sup> of Oil	Heating Value g-cal/L
In-situ	7000	9000
Direct combustion	1800	9000
Indirect combustion	180	90,000

The in-situ process produces the highest retort gas flow rate due to the combined effect of the higher retort temperatures converting more of the kerogen to gas and the higher dilution gas flow required to provide adequate oxygen to burn the shale. The direct combustion retort has similar conditions (i.e., high temperatures and requirement for adequate oxygen for combustion) but to a lesser degree than the in-situ retort and, consequently, has lower retort gas flow rates. The indirect combustion process has the lowest retort gas flow rate due to the lower retort temperatures and low gas flow rate with no dilution required to provide oxygen.

The heating value of the retort gas is determined by the amount of dilution gas. In-situ and direct combustion retorts produce low heating value gas at 9000 g-cal/L (100 Btu/scf) and the indirect combustion retort produces high heating value gas at 90000 g-cal/L (1000 Btu/scf).

The retort gas flow and heating value determine the net exhaust gas flow after combustion. As the performance of the air pollution controls is often determined by an exit concentration (ppm or g/m<sup>3</sup>), high gas flow rates result in higher pollutant emissions.

#### Sulfur Gases

During the retorting, the sulfur in the raw shale is partitioned to the spent shale (60 percent), oil (10 percent), and retort gas (30 percent). The significant variations in raw shale sulfur content, percentage of sulfur partitioned to the gas phase, and chemical structure of these sulfur gases result in the sulfur gas cleanup strategy being quite difficult.

The sulfur emission problem can be solved either by removing the sulfur prior to combustion or by adding a flue gas desulfurization process after combustion. As the combustion process dilutes the pollutant concentra-

tions and increases the gas flow rate, the economically preferred technique usually is sulfur removal prior to combustion.

The form of the sulfur in the gas is extremely important when considering sulfur removal processes. Sulfur recovery processes that have been considered for cleaning the retort gas prior to combustion are not effective in removing organic sulfur compounds which can amount to as much as 10-16 percent of the total sulfur in the retort gas. Consequently, the effectiveness of these cleanup processes depends on the relative amounts of organic sulfur to  $H_2S$ . Even high efficiencies of  $H_2S$  removal (99 percent) are not sufficient to reduce the sulfur emissions below the 850 kg/1000  $m^3$  of oil (0.3 lb/bbl) regulatory level for Colorado if there are significant amounts of organic sulfur gases.

To avoid the costly alternative of adding an end-of-pipe flue gas desulfurization, two alternatives can be considered. The first, the activated carbon-hypochlorite  $H_2S$  removal process, is an improvement on the  $H_2S$  scrubbing process which also removes organic sulfur species (Reference 11). Therefore, this process is effective for removing sulfur gases prior to combustion, eliminating the need for more expensive post combustion control. The activated carbon-hypochlorite process reports removal of 99+ percent of the  $H_2S$  and 90-98+ percent of the organic sulfur gases. This results in a net sulfur removal efficiency of 99 percent and sulfur emissions ( $SO_x$ ) of 500 kg/1000  $m^3$  oil (0.17 lb/bbl) even when the organic sulfur gases are 15 percent of the total sulfur.

The second alternative to the use of post-combustion  $SO_x$  control is the indirect combustion-solids recycle retort process which limits sulfur gas emissions by the chemistry of the retort and combustion process. The sulfur contained in the retort gases from the recycle solids process can be as low as 1 percent of the total sulfur content in the feed with proper design of the retort. [The remaining sulfur is partitioned to the oil (10 percent) and the spent shale (89 percent)]. Therefore, the amount of organic sulfur is minimal, and the  $H_2S$  removal processes alone are sufficient to reduce the sulfur emissions below the regulatory limit.

The design conditions used for the  $H_2S$  removal process determine the residual  $H_2S$  and organic sulfur in the retort gas that eventually are emitted as sulfur oxides. The processes considered are:

1. Direct or indirect conversion of the sulfur (e.g., Stretford, Lo-Cat, Unisulf, alkaline, or amine scrubbing)

$H_2S$  exit concentration = 50 ppm  
organic sulfur assumed at 5 percent  
of total sulfur in retort gas  
- no removal

## 2. activated carbon-hypochlorite process

$H_2S$  exit concentration = 10 ppm  
organic sulfur - 90 percent removal

Two process operations result in the direct emission of sulfur oxides from the retort: the circular grate direct heated retort and the fluidized bed combustion of the spent shale. The design conditions for these two processes were taken from the literature (References 8 and 9).

Circular Grate Retort -  $SO_x$  = 175 ppm in retort gas  
Fluidized Bed Spent Shale Combustor in Retort Gas -  
 $SO_x$  = 20 ppm

### Nitrogen Gases

The removal of nitrogen gases is also difficult to predict due to the degree of variability of nitrogen content in shale, partitioning between gas, oil, and spent shale, and chemical form of the gaseous nitrogen species.

Using the data reported in the PSD permit applications and the Pollution Control Technical Manuals, the partitioning of the nitrogen was estimated as shown in Table 5.

Table 5. PARTITIONING OF NITROGEN IN RETORT

Process	% of Raw Shale Nitrogen in Product		
	Spent Shale	Oil	Retort Gas
In-situ (MIS)	21	25	54
Solids Recycle (Lurgi) (Chevron)	5	55	10 <sup>(a)</sup>
Direct Combust'n (Paraho)	33	37	30

(a) Remaining nitrogen content in the spent shale after retorting is burned in the lift pipe or fluidized combustor and exits with the flue gas.

The nitrogen content of the retort off-gas consists primarily of ammonia with smaller amounts of other nitrogen compounds. In a semi-quantitative investigation of nitrogen-containing species from an in-situ and above-ground retort process, hydrogen cyanide, various nitriles, pyrrole, pyridine, methyl and diethyl aniline, and other nitrogen gas species were identified (Reference 12). The organic nitrogen content of the retort gas was found to be as much as 1-2 percent of the ammonia content.

The presence of organic nitrogen species presents the same problem for limiting fuel-related  $NO_x$  emissions as that described above for the  $SO_x$  emissions; namely that the removal processes generally considered are not effective in reducing the organic nitrogen content of the retort gas.

The primary nitrogen removal technique considered is removal of ammonia from the retort gas by a water-wash absorption tower followed by an ammonia recovery stripper. The outlet ammonia concentration is deter-

mined by the effectiveness of the ammonia absorber. At atmospheric pressure the equilibrium exit partial pressure for ammonia at 50°C is 0.5 mm Hg.

The nitrogen content of the treated retort gas, and the subsequent NO<sub>x</sub> emissions from combustion of the retort gas, is determined by:

- the exit gas ammonia concentration (660 ppm NH<sub>3</sub>)
- the amount of retort gas produced by the retort (Table 4)
- the amount of nitrogen partitioned to the retort gas (Table 5)
- the percentage of nitrogen present as organic nitrogen compounds (2 percent)

The design conditions used to determine the NO<sub>x</sub> emissions from burning the retort gas are:

- water wash - NH<sub>3</sub> in exit gas based on  
NH<sub>3</sub> partial pressure = 0.5 mmHg  
organic nitrogen based on 2% of  
nitrogen in retort gas and no  
removal with water wash
- thermal NO<sub>x</sub> from retort gas rate,  
heating value and 0.2 lb/10<sup>6</sup> Btu
- acid wash - same as water wash except NH<sub>3</sub>  
assumed = 10 ppm

The processes that utilize the combustion of high-nitrogen-content spent shale for energy recovery can produce high NO<sub>x</sub> emissions if proper staging of the combustion is not used. For PSD permit applications, NO<sub>x</sub> emissions were based on a high estimate of 15 percent for the conversion of the nitrogen in the spent shale to NO<sub>x</sub> in the combustor. This level of conversion was also found by Lawrence Livermore Laboratory investigators who did not attempt to stage the combustion (Reference 12).

The principle of NO reduction in a staged combustor can be applied to reduce these high NO<sub>x</sub> emissions to approximately 3 percent nitrogen conversion to NO<sub>x</sub>.

#### RETORT GAS COMBUSTION AND END-OF-PIPE

The end-of-pipe controls are those either added after combustion of the retort gas to remove particulate, NO<sub>x</sub>, and SO<sub>x</sub>, or incorporated as part of the combustion process as in staged combustion for NO<sub>x</sub> control.

#### Particulate

For particulate control, two alternatives were considered. The first is the base case using a standard baghouse. The second control technique is the combined dry venturi-baghouse (Reference 13).

The dry venturi-baghouse combination provides for particulate control that is somewhat independent of type of particulate. The applicants for PSD permits all considered a minimum particulate exit loading of 0.07 g/m<sup>3</sup> (0.03 gr/scf) which was based on standard

technology within the limits of the unknowns associated with oil shale particulate. By capturing the small particles on larger target particles of specified physical properties, the dry venturi eliminates the major uncertainties in designing baghouses with respect to particulate type and size.

Two design conditions based on the face velocity in the baghouse of 0.5 and 1.5 m/sec were used (Reference 14):

<u>particulate loading</u>	<u>face velocity</u>
<u>g/m<sup>3</sup></u>	<u>m/sec</u>
0.02	0.5
0.001	1.5

#### Sulfur Oxides

If the H<sub>2</sub>S (and organic sulfur) removal is not sufficient to reduce the sulfur emissions to an acceptable level, a post-combustion flue gas desulfurization system must be added. This could be either a wet or dry scrubber.

Another sulfur control technique is the use of a spent shale combustor. The combustion of the spent shale has two important advantages: 1) recovery of the energy value of the char, and 2) reduction of the sulfur oxide emissions due to the scrubbing nature of the spent shale. However, spent shale combustion also has two distinct disadvantages: 1) high emissions of NO<sub>x</sub> from the nitrogen in the spent shale, and 2) high emissions of CO due to incomplete combustion. These emissions (NO<sub>x</sub> and CO) are discussed in the following section.

The design conditions for SO<sub>x</sub> emissions used in the analysis are:

- Flue Gas Desulfurization - 50 ppm SO<sub>x</sub> exit concentration
- Combustion of spent shale with retort gas
  - 10 ppm SO<sub>x</sub>
  - 300 ppm NO<sub>x</sub>
  - 1000 ppm CO

#### Nitrogen Oxides

Two controls were considered for reducing post-combustion NO<sub>x</sub> emissions. The first is ammonia injection; this technique has been applied successfully in utility boilers and could be used when the retort gas is burned in a conventional boiler for steam and electrical generation.

The second NO<sub>x</sub> control considered is staged combustion which has particular advantages for spent shale combustion due to its ability to adequately control fuel related NO<sub>x</sub>. The staged combustion could be applied to either the conventional boiler or the spent shale combustor.

Selective catalytic reduction (SCR) was not considered due to its potential for poisoning the catalyst.

The retort gas particulate contains a wide variety of heavy metals which have a deleterious effect on catalyst life. In addition, there are still a number of unknown factors which can affect the long term catalyst performance that have not been completely identified. For example, it had been assumed that the mercury associated with the retort gas was in the form of elemental mercury and would be substantially removed prior to combustion during the standard gas cleaning (ammonia and hydrogen sulfide removal) processes. However, it has been shown that the mercury is present primarily as methyl mercury which is volatile and is present in the retort gas during combustion (Reference 15). Consequently, any post-combustion control processes must be capable of handling these emissions of elemental and oxides of mercury. This is only one instance where unknown factors could have a negative effect on catalyst performance. Consequently, due to the inherently variable nature of the retort gas from an oil shale retort and the known presence of many catalyst poisons, the use of SCR was not considered.

There is a tradeoff between the  $\text{NO}_x$  and CO emissions in the spent shale combustor. As indicated above, the  $\text{NO}_x$  and CO emissions are quite high (300 and 1000 ppm, respectively). Higher combustor temperatures increase the  $\text{NO}_x$  emissions but decrease the CO emissions. In the range of 600-800°C the  $\text{NO}_x$  emissions can range from 250 to over 600 ppm, while the CO emissions can vary from 200 to over 1000 ppm at the lower temperatures with low excess oxygen.

In addition, the staged combustion technique of controlling fuel related  $\text{NO}_x$  depends on low excess oxygen (perhaps sub-stoichiometric combustion) which would further increase the CO emissions.

The fluidized bed combustor has limitations in process control which result in its inability to provide conditions that result in adequate staging for  $\text{NO}_x$  control. However, a cascading bed combustor may be designed as a staged device (Reference 12). Consequently, combustion conditions can be controlled at each stage of the process, alternating between fuel rich and fuel lean zones to reduce the NO formed to  $\text{N}_2$  and complete the combustion of the CO formed to  $\text{CO}_2$ .

There are as yet no specific test results of the staged combustion with spent shale. However, the reaction kinetics of the reduction of NO to  $\text{N}_2$  with spent shale have been investigated (Reference 12), and the engineering design of the cascading bed combustor is ideal for a staged system with easy means for controlling the process conditions.

The design conditions for post-combustion  $\text{NO}_x$  control are:

- $\text{NH}_3$  injection - 20 ppm  $\text{NO}_x$  exit concentration
- Cascading bed combustor - 50 ppm  $\text{NO}_x$   
- 50 ppm CO

## EMISSIONS FROM RETORT GAS COMBUSTION

The results for the emissions from the retort gas combustion from the analysis for all five cases are shown for particulates, sulfur oxides, and nitrogen oxides in Tables 6, 7, and 8, respectively. The total facility emissions for each of the five cases are shown in Tables 9 through 13. The emissions from combustion of the retort gas for particulates, nitrogen oxides, and sulfur oxides, are also shown in Figures 8, 9, and 10, respectively.

These figures indicate that there is wide variation in emission levels for the five processes based on the present day technology (Base Case conditions). For particulates, the emission levels vary from 200 to 800 kg/1000  $\text{m}^3$  of oil; for nitrogen oxides the emission levels vary from 1000 to 8000 kg/1000  $\text{m}^3$  of oil; for sulfur oxides the emission levels vary from 350 to 3000 kg/1000  $\text{m}^3$  of oil.

The first alternative considered was the use of the activated carbon enhanced  $\text{H}_2\text{S}$  removal process, an acid wash for improved ammonia removal, and the addition of a dry venturi-baghouse for post-combustion particulate control. Referring to Figures 8, 9, and 10, the emission levels for alternate No. 1 show considerably less variation, particularly for sulfur oxides (range from 100 to 250 kg/1000  $\text{m}^3$  of oil) and particulates (range from 50 to 200 kg/1000  $\text{m}^3$  of oil). The variation of nitrogen oxide emissions is still considerable, ranging from 1000 to 4000 kg/1000  $\text{m}^3$  of oil. Essentially, the acid wash removes only the residual ammonia (without affecting the organic nitrogen content) and has no effect on the thermal  $\text{NO}_x$ ; therefore, there is relatively little improvement in the  $\text{NO}_x$  emission rate.

The second alternative considered was the use of ammonia injection for  $\text{NO}_x$  control from boiler and/or furnace combustion, the use of staged combustion for control of  $\text{NO}_x$  emissions from the spent shale combustor, and the dry venturi-baghouse with an increased space velocity which improves collection performance at the expense of increased pressure drop. Again, referring to Figures 8, 9, and 10, it is apparent that the addition of these controls essentially levels the performance of all five processes.

Figures 11, 12, and 13 show the particulate, nitrogen oxide, and sulfur oxide emission levels for alternate No. 2 conditions along with the total facility emissions. The particulate emissions, Figure 11, still show variation from 4 to 12 kg/1000  $\text{m}^3$  of oil. However, the absolute value is considerably less than particulate emissions from the mining and solids handling operations, and the total facility is essentially equivalent for all five cases, ranging from 180 to 200 kg/1000  $\text{m}^3$  of oil.

The nitrogen oxide emissions (Figure 12) range from 75 to 500 kg/1000  $\text{m}^3$  of oil. While this is still a sig-

nificant variation, again the absolute magnitude of the values is such that the net variation in the total  $\text{NO}_x$  emissions for the five facilities is less than a factor of 2, ranging from 400 to 800 kg/1000  $\text{m}^3$  of oil.

The sulfur oxide emissions (Figure 13) range from 100 to 250 kg/1000  $\text{m}^3$  of oil and are essentially the same for the total facility as there are no other significant sources of sulfur emissions.

The basic conclusion derived from the above analysis is that, although the air emission levels for the different retort processes with controls considered to be Best Available Control Technology (BACT) can vary considerably, sometimes by as much as two orders of magnitude, the application of control techniques that are either improvements over existing technology or more suitable for a specific application, results in similar emission levels for all five processes considered. This statement does need to be qualified by the fact that some of the control techniques considered have not been applied specifically to the oil shale recovery process, and therefore cannot be considered as BACT. However, these techniques have been proven at the full scale level in various other difficult control applications.

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Table 6. PARTICULATE EMISSIONS

Case Process	Retort		Gas		Base		Alt. 1		Alt. 2	
							Face Velocity =		Face Velocity =	
							1.5 ft/sec		3.5 ft/sec	
	HHV	Gas	Combust'n	Flow	Part.	kg/	Part.	kg/	Part.	kg/
	cal/l	ft <sup>3</sup> /	Dilution	m <sup>3</sup> /m <sup>3</sup>	Loading	1000 m <sup>3</sup>	Loading	1000 m <sup>3</sup>	Loading	1000 m <sup>3</sup>
		bbl	Ratio	Oil	g/m <sup>3</sup>	of Oil	g/m <sup>3</sup>	of Oil	g/m <sup>3</sup>	of Oil
1. Direct combustion	9000	10000	2	3521	0.07	246	0.02	70	0.001	4
2. Direct combustion circular	9000	10000	2	3521	0.07	246	0.02	70	0.001	4
3. Indirect combust-gas	90000	1000	15	2641	0.07	185	0.02	53	0.001	3
4. Indirect combust-solids-recy.	9000	1000	15	2641	0.07	185	0.02	53	0.001	3
fluidized bed comb.		53000	1	9331	0.07	653	0.02	187	0.001	9
TOTAL		54000		11972	0.07	838	0.02	24	0.001	12
5. Modified in-situ (a)	9000	30000	2	10563	0.07	739	0.02	211	0.001	11
above ground-ind. gas recy.	90000	400	15	1056	0.07	74	0.02	21	0.001	1
TOTAL		30400		11619		813		232		12

(a) based on 60% of oil produced



Table 7. SULFUR OXIDE EMISSIONS

Activated Carbon Process										
Case Process	Organic S		SO <sub>x</sub>		SO <sub>x</sub>		Removal		SO <sub>x</sub>	
	H <sub>2</sub> S ppm	5% of H <sub>2</sub> S kg/1000 m <sup>3</sup> Oil	Emission kg/1000 m <sup>3</sup> Oil	Emission kg/1000 m <sup>3</sup> Oil	SO <sub>x</sub> Exit ppm	H <sub>2</sub> S (SO <sub>x</sub> ) ppm	Eff. for Organics %	SO <sub>x</sub> Emission kg/1000 m <sup>3</sup> Oil	SO <sub>x</sub> Emission kg/1000 m <sup>3</sup> Oil	SO <sub>x</sub> Exit ppm
1. Direct combustion	50	1197	199	2593	736	10	90	40	159	45
2. Direct combustion-circular grate	175(a)	0		370	105	50(a)			106	50
3. Indirect combustion-gas recycle	50	1197	20	2414	914	10	90	4	124	47
4. Indirect combustion-solid recycle	50	43(b)	20	106	40	10	90	4	8	3
fluidized	20			224	24				224	24
			0	330						
5. Modified in-situ	50	718	597	2033	192	10	90	119	191	18
above ground-indirect gas recy.	50	480	8	968	916	10	90	2	50	47
				3000					241	

(a) 175 ppm SO<sub>x</sub>

(b) low organic sulfur due to solids capture of H<sub>2</sub>S in retort

Table 8. NITROGEN OXIDE EMISSIONS

Case Process	NH <sub>3</sub>				Alt. 1				Alt. 2			
	Part. Press. = 0.5mmHg				Acid wash				NH <sub>3</sub> Injection			
	Exit	Organic	Fuel	Thermal	Exit	Fuel	NO <sub>x</sub>	Total	Exit	Conc	NO <sub>x</sub>	Total
	kg/1000	Nitrogen	NO <sub>x</sub>	NO <sub>x</sub>	Conc	NO <sub>x</sub>	kg/1000	kg/1000	Conc	NO <sub>x</sub>	kg/1000	kg/1000
	m <sup>3</sup> Oil	2% of N	kg/1000	m <sup>3</sup> of Oil	ppm	kg/1000	m <sup>3</sup> of Oil	m <sup>3</sup> of Oil	ppm	ppm	m <sup>3</sup> Oil	m <sup>3</sup> Oil
1. Direct combustion	790	256	2242	570	799	586	1156	2812	328	NH <sub>3</sub> -inj	20	85
2. Direct combustion-circular	790	256	2242	570	799	586	1156	2812	328	NH <sub>3</sub> -inj	20	85
3. Indirect combust-gas recycle	79	85	351	570	349	186	756	921	286	NH <sub>3</sub> -inj	20	63
4. Indirect combust-solid recycle	79	85	351	570	349	186	756	921	286	NH <sub>3</sub> -inj	20	63
fluidized	300(a)		3359	0	360		3359	3359	360	stgd/cbn	50	560
lift gas			0	0			4115	4281				623
5. Modified in-situ-	2370	258	5632	1710	695	665	3291	3457	225	NH <sub>3</sub> -inj	20	486
above ground-in	32	34	141	228	349	74	302	369	286	NH <sub>3</sub> -inj	20	254
												25
												279

(a) Based on 15% conversion of nitrogen in spent shale to NO<sub>x</sub>.

Table 9. TOTAL FACILITY EMISSIONS

Case 1 - Direct Combustion  
(Paraho type retort)

Base Conditions; H<sub>2</sub>S removal (50 ppm), NH<sub>3</sub> water wash  
Particulate loading = 0.07 g/m<sup>3</sup>

Emissions, kg/1000 m<sup>3</sup> of oil

Base Case Source	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Open pit	370	50	471	38	410
Retort gas	125	35	2812	2593	246
Upgrade	25	150			
Total	520	235	3283	2631	656

Alternate 1 SO<sub>x</sub> - H<sub>2</sub>S removal - activated carbon  
NO<sub>x</sub> - NH<sub>3</sub> removal - water & acid wash  
PM - dry venturi & baghouse  
room & pillar mining

Pollutant	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	150	20	345	20	181
Retort gas	125	35	1156	159	70
Upgrade	25	150			
Total	300	205	1501	179	251
Reduction	220	30	1782	2451	405
% Reduction	42	13	54	93	62

Alternate 2 NO<sub>x</sub> - ammonia injection  
PM - dry venturi/baghouse  
HC & CO - vehicles  
catalytic converter

Pollutant	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	85	159	4
Upgrade	2	60			
Total	142	97	430	179	185
Reduction	158	108	1071	0	67
% Reduction	52	53	71	0	27

Table 10. TOTAL FACILITY EMISSIONS

Case 2 - Direct Combustion  
Circular Grate Retort

Base Case	Emissions, kg/1000 m <sup>3</sup> of oil				
Pollutant	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	150	20	345	20	181
Retort gas	125	35	2812	370	246
Upgrade	25	150			
Total	300	205	3157	390	427

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Alternate 1 SO<sub>x</sub> - Flue Gas Desulfurization  
 NO<sub>x</sub> - NH<sub>3</sub> removal - water & acid wash  
 PM - dry venturi/baghouse  
 HC & CO - vehicles  
 catalytic converter

Pollutant	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	1156	106	70
Upgrade	2	60			
Total	142	97	1501	126	251
Reduction	158	108	1656	264	176
% Reduction	52	53	52	68	41

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Alternate 2 NO<sub>x</sub> - ammonia injection  
 PM - dry venturi/baghouse

	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	85	106	4
Upgrade	2	60			
Total	142	97	430	126	185
Reduction	0	0	1226	0	66
% Reduction	0	0	74	0	26

Table 11. TOTAL FACILITY EMISSIONS

Case 3 - Indirect Combustion  
Gas Recycle Retort (Union)

		Emissions, kg/1000 m <sup>3</sup> of oil				
Base Case Process	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM	
Room & pillar	15	20	345	38	181	
Retort	125	35	921	2414	185	
Upgrade	25	150	-----No	Data-----		
Total	165	205	1266	2452	366	
<hr/>						
Alternate 1	NO <sub>x</sub> - NH <sub>3</sub> removal - water & acid wash SO <sub>x</sub> - H <sub>2</sub> S removal - activated carbon PM - dry venturi/baghouse					
Pollutant	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM	
Room & pillar	15	2	345	20	181	
Retort	125	35	756	124	53	
Upgrade	2	60				
Total	142	97	1101	144	234	
Reduction	22	108	166	2308	132	
% Reduction	14	53	13	94	36	
<hr/>						
Alternate 2	NO <sub>x</sub> - ammonia injection PM - dry venturi/baghouse					
Pollutant	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM	
Room & pillar	15	2	345	20	181	
Retort gas	125	35	63	124	3	
Upgrade	2	60				
Total	142	97	408	144	184	
Reduction	0	0	692	0	50	
% Reduction	0	0	63	0	21	

Table 12. TOTAL FACILITY EMISSIONS

Case 4 - Indirect Combustion  
Solids Recycle/Fluidized Bed Combustor

Emissions, kg/1000 m <sup>3</sup> of oil					
Process	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	150	20	345	20	181
Retort gas	125	35	921	106	185
Combustion	11197		3359	224	653
Upgrade	25	150	No Data		
Total	11497	205	4626	350	1019
-----					
Alternate 1 NO <sub>x</sub> - NH <sub>3</sub> removal - water & acid wash SO <sub>x</sub> - H <sub>2</sub> S removal-activated carbon PM - dry venturi/baghouse HC & CO - vehicles catalytic converter					
	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	756	8	53
Combustion	11197		3359	224	187
Upgrade	2	60			
Total	11340	97	4460	252	420
Reduction	158	108	166	98	599
% Reduction	1	53	4	28	59
-----					
Alternate 2 NO <sub>x</sub> - ammonia injection for retort staged combustion for combustor gas cascading bed spent shale combustor PM - dry venturi					
	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	63	8	3
Combustion	423		423	169	9
Upgrade	2	60			
Total	565	97	831	197	193
Reduction	10775	0	3629	55	227
% Reduction	95	0	81	22	54

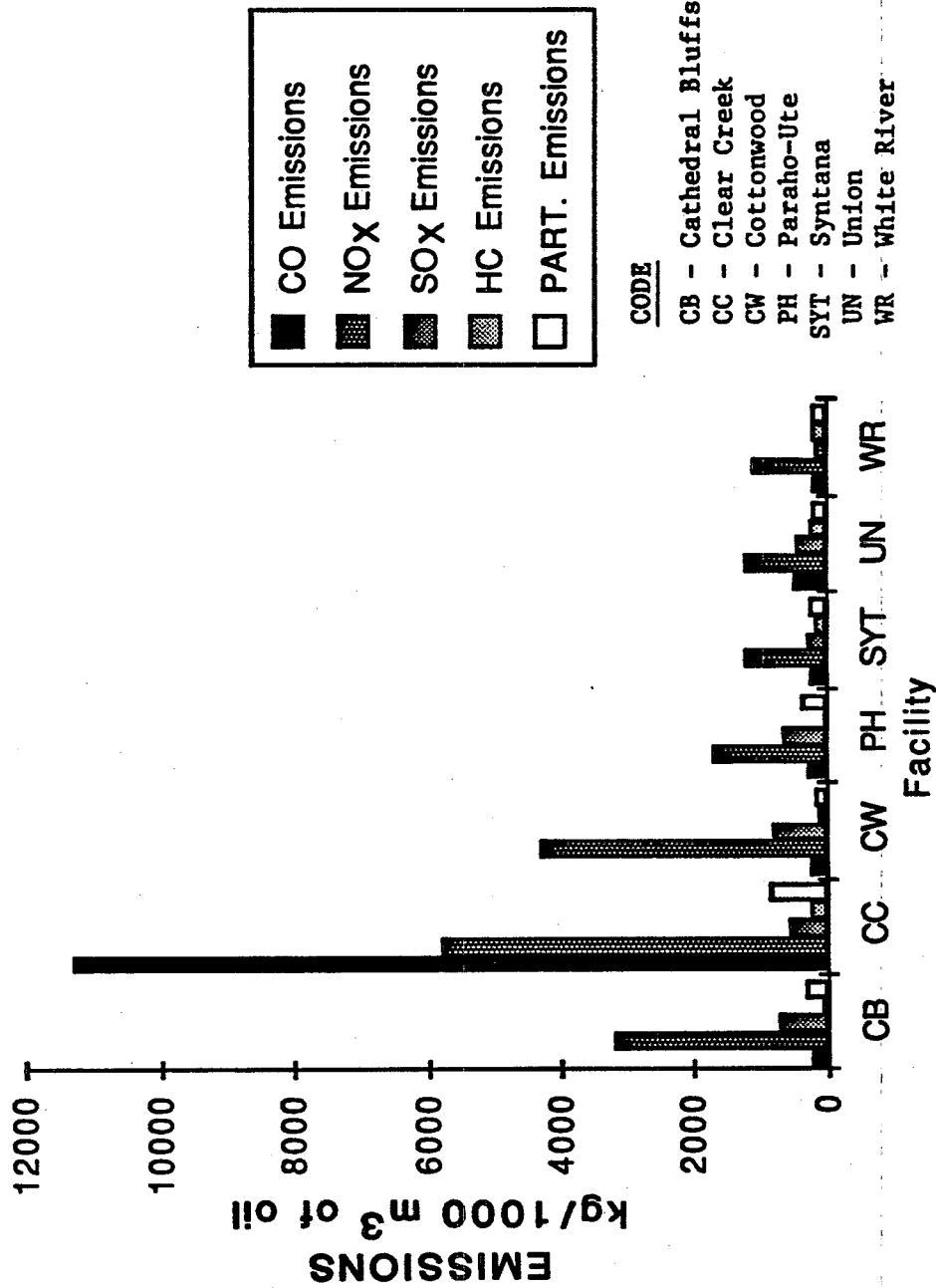
Table 13. TOTAL FACILITY EMISSION

Case 5 - Modified In-situ  
Indirect Combustion Above-Ground

Emissions, kg/1000 m <sup>3</sup> of Oil					
	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	150	20	345	20	181
Retort gas in-situ	72	35	7342	2033	739
Above ground	53		369	968	74
Upgrade	25	150			
Total	300	205	8056	3020	994
-----					
Alternate 1 NO <sub>x</sub> - NH <sub>3</sub> removal - water & acid wash SO <sub>x</sub> - H <sub>2</sub> S removal-activated carbon PM - dry venturi/baghouse HC & CO - vehicles catalytic converter					
	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	15	2	345	20	181
Retort gas in-situ	72	35	2375	191	211
Above ground	53	0	302	50	21
Upgrade	2	60			
Total	142	97	3022	261	413
Reduction	158	108	5034	2760	581
% Reduction	52	53	62	91	58
-----					
Alternate 2 NO <sub>x</sub> - ammonia injection PM - dry venturi/baghouse					
	CO	HC	NO <sub>x</sub>	SO <sub>x</sub>	PM
Room & pillar	15	2	345	20	181
Retort gas in-situ	72	35	254	191	11
Above ground	53	0	25	50	1
Upgrade	2	60			
Total	142	97	624	261	193
Reduction	0	0	2398	0	221
% Reduction	0	0	79	0	53

Figure 1.

# TOTAL FACILITY EMISSIONS SUMMARY





# POSSIBLE PROCESSING COMBINATIONS

Figure 2.

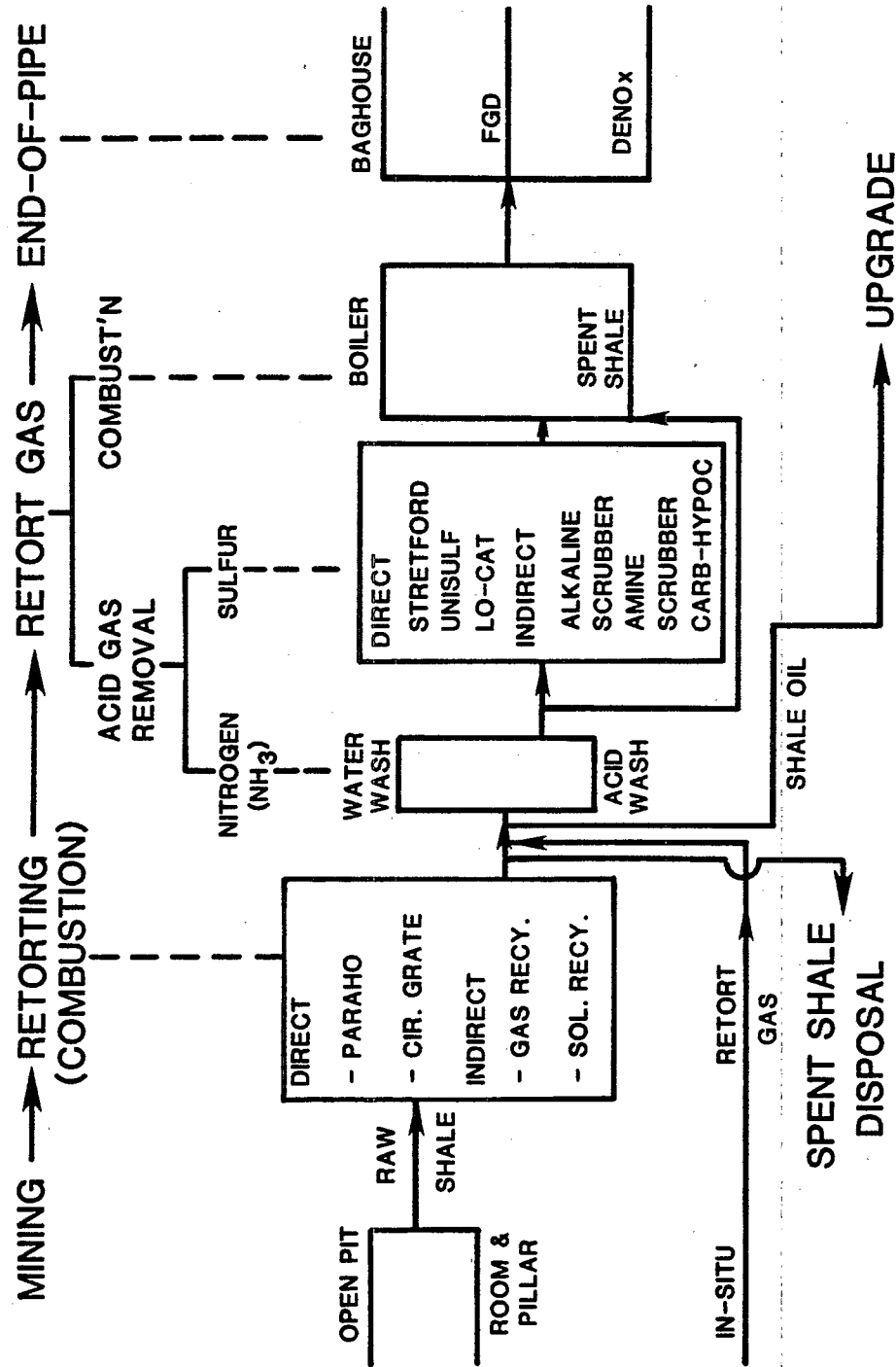


Figure 3.

## CARBON MONOXIDE EMISSIONS

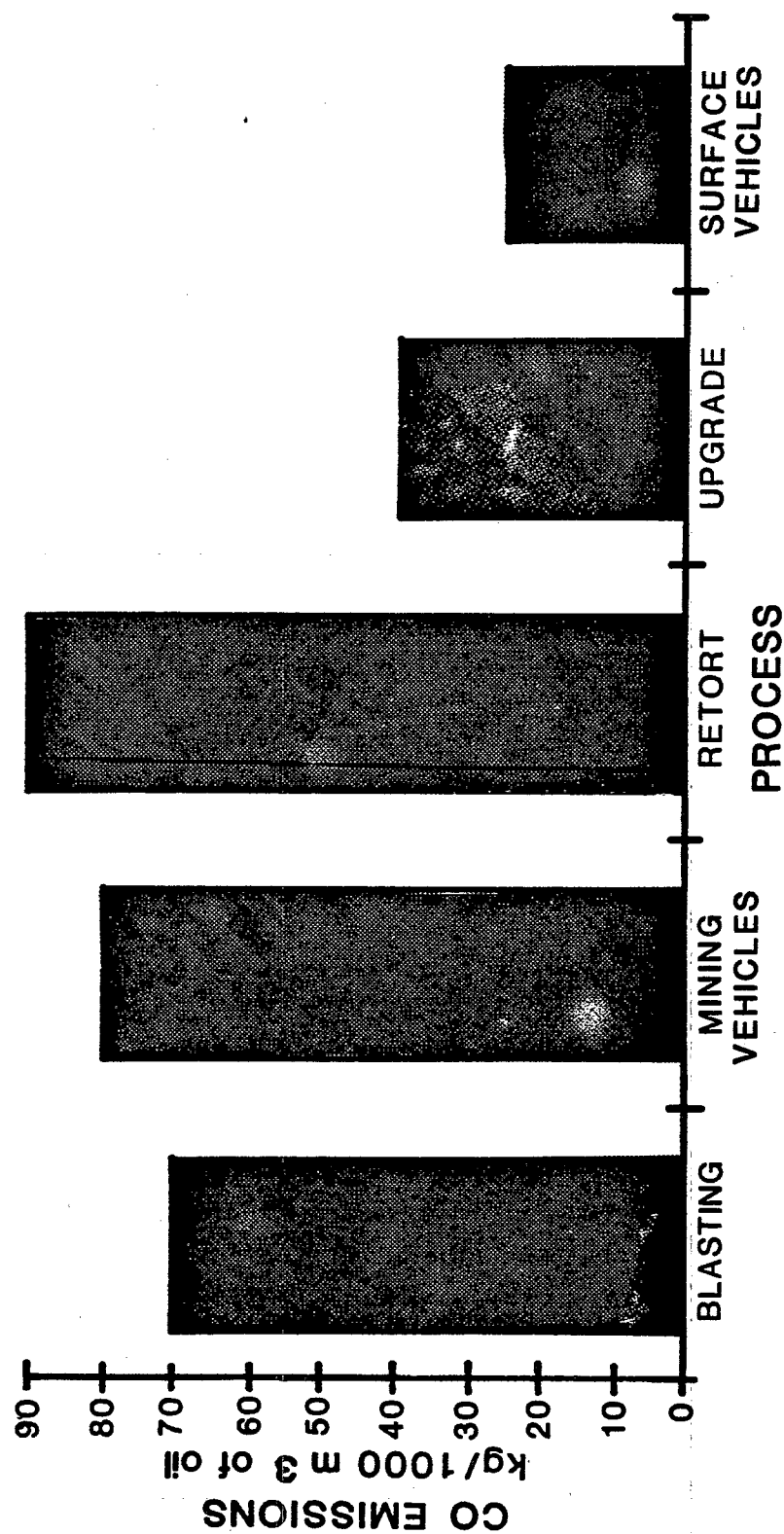


Figure 4.

# HYDROCARBON EMISSIONS

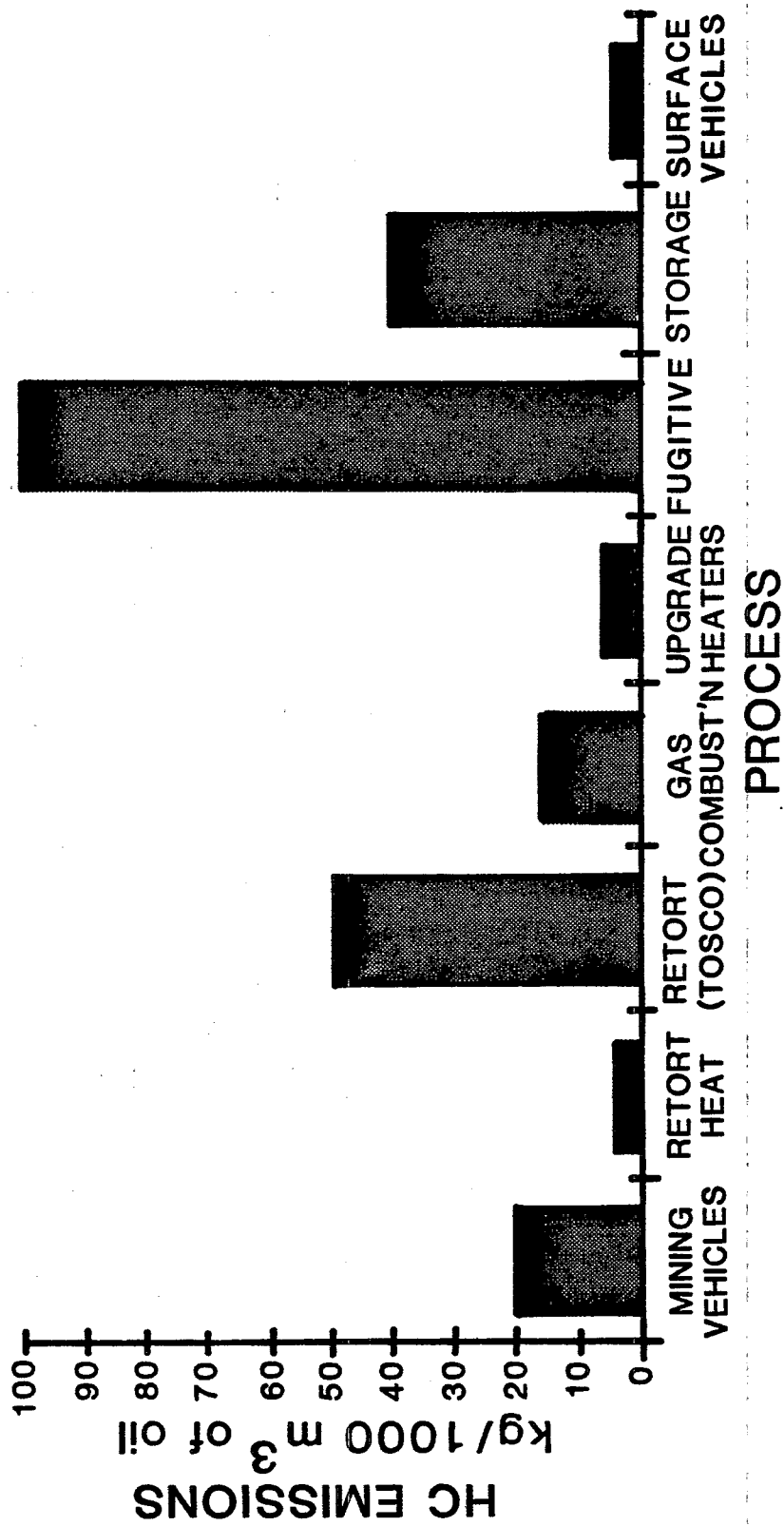


Figure 5.

# NITROGEN OXIDES EMISSIONS

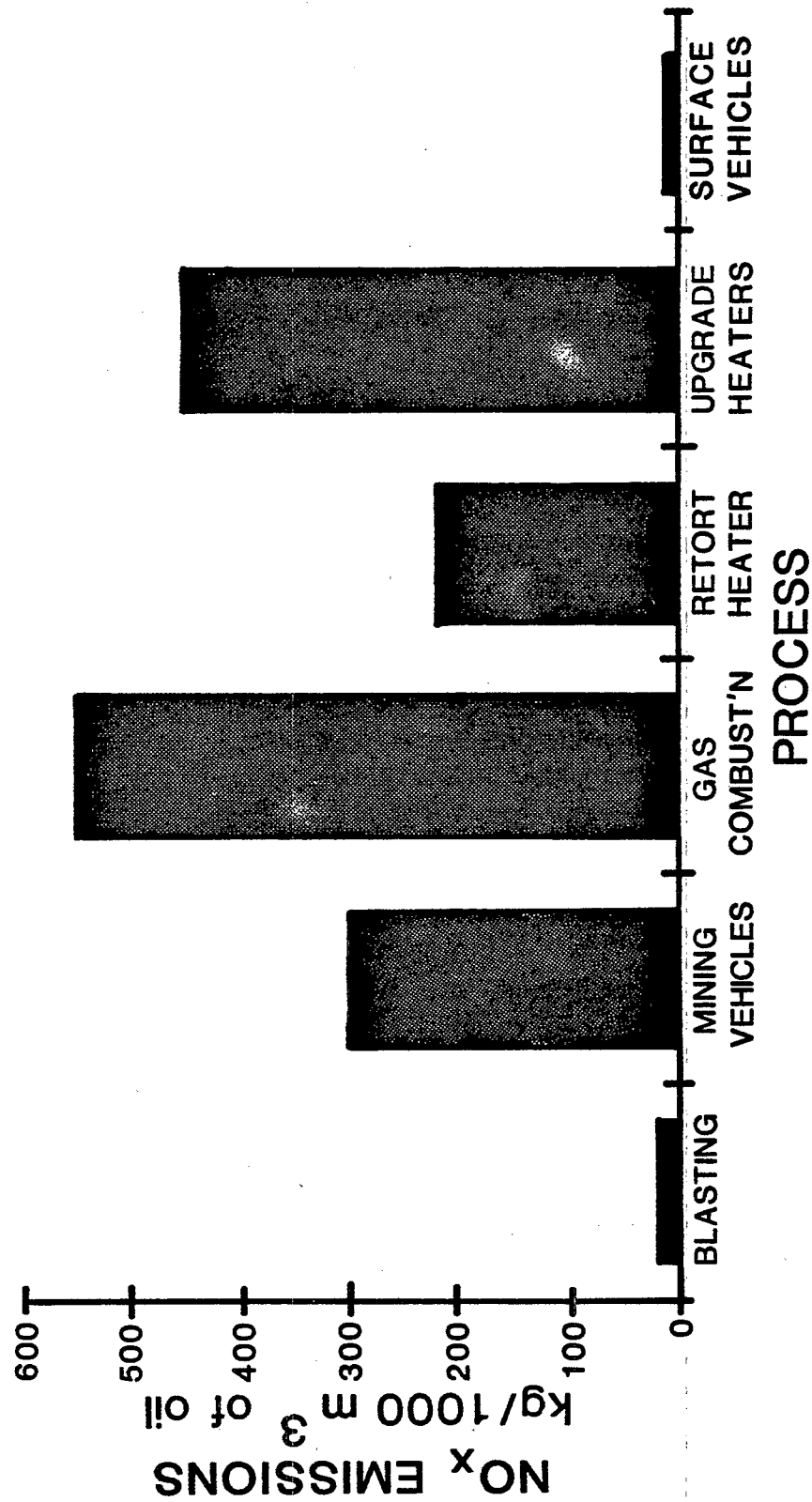


Figure 6.

## SULFUR OXIDES EMISSIONS

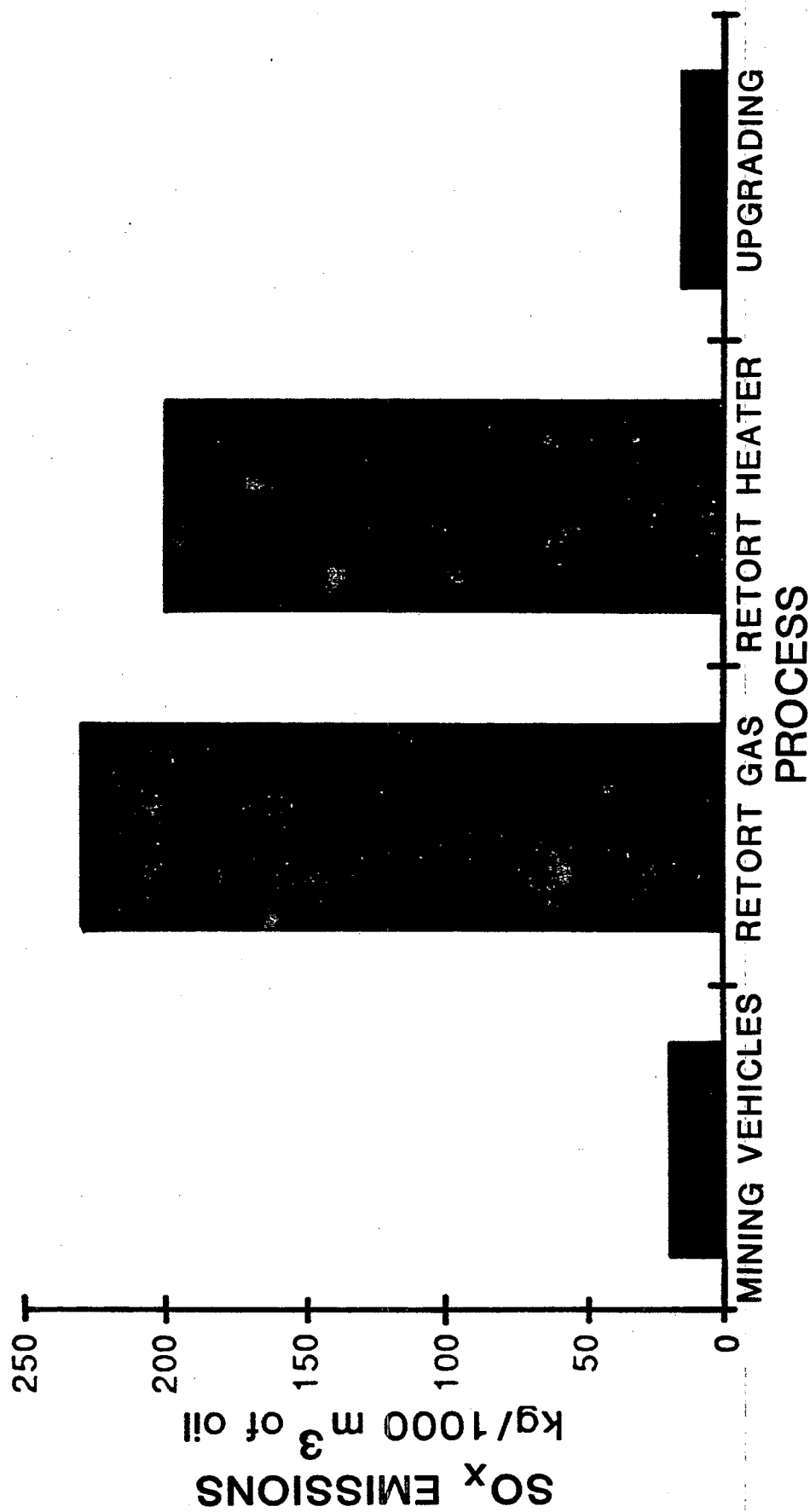


Figure 7.

# PARTICULATE EMISSIONS

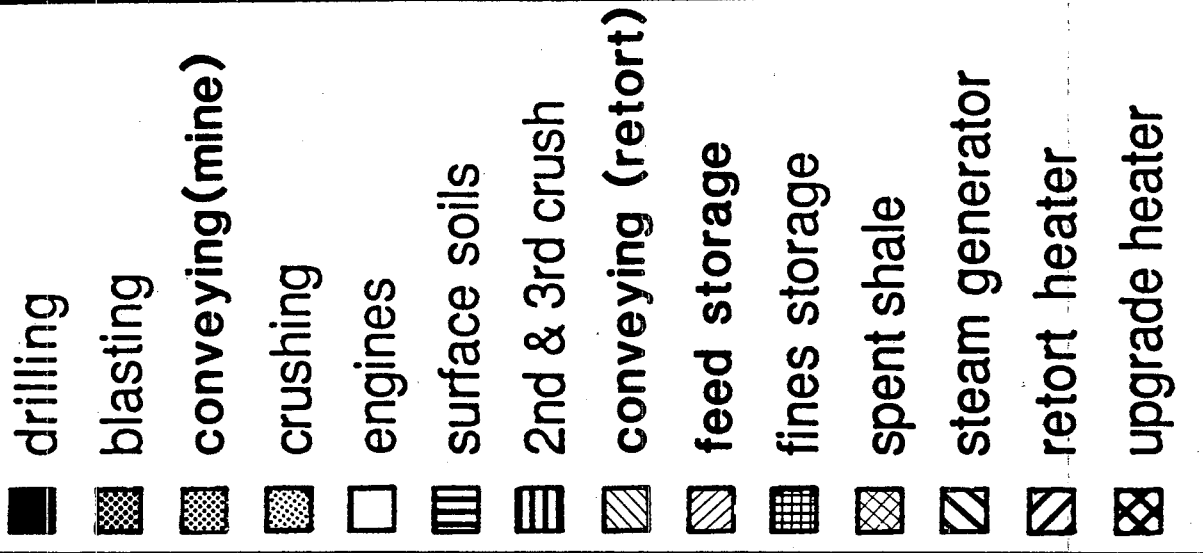
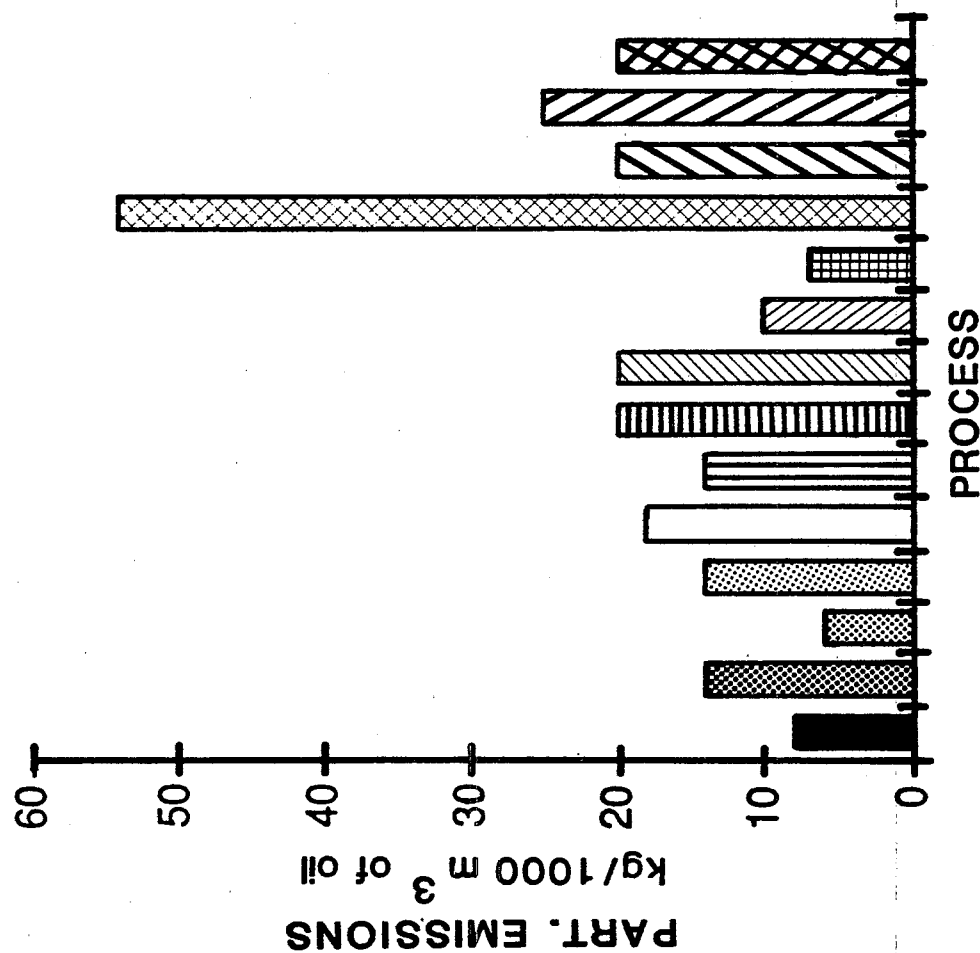


Figure 8.

# PARTICULATE EMISSIONS FROM RETORT GAS COMBUSTION FOR FIVE CASES

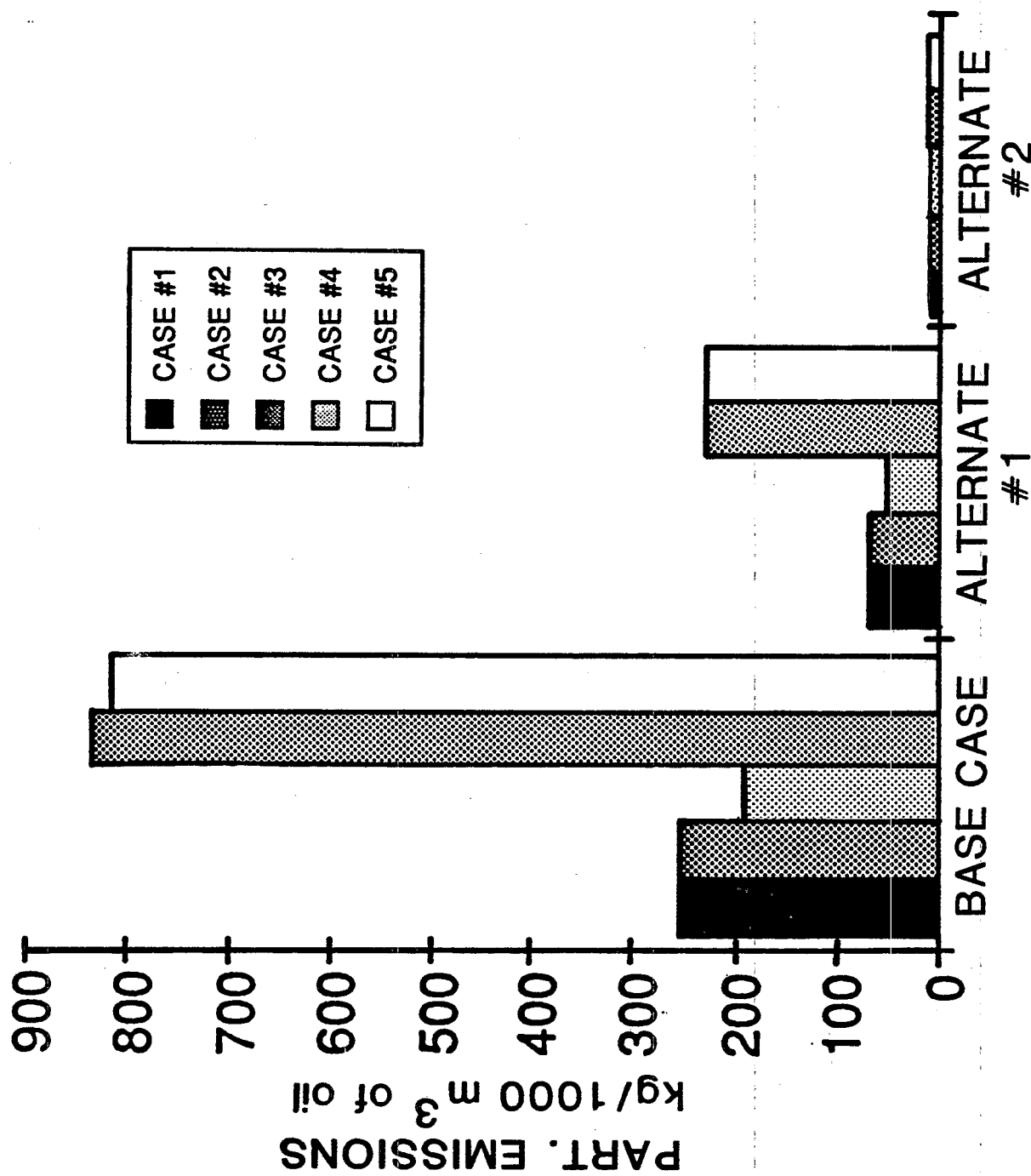


Figure 9.

# **NITROGEN OXIDES EMISSIONS SUMMARY FOR FIVE CASES**

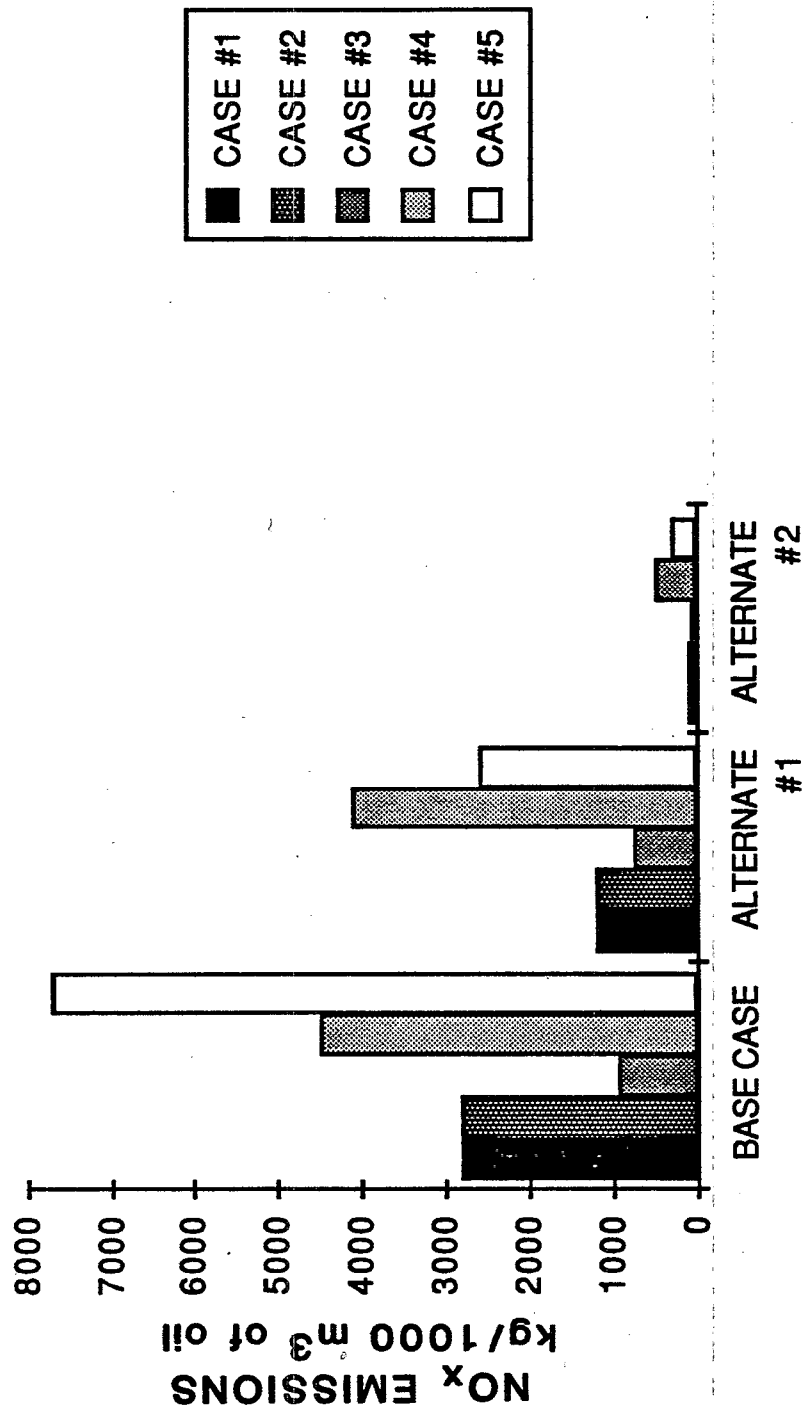




Figure 10.

# **SULFUR OXIDES EMISSIONS SUMMARY FOR FIVE CASES**

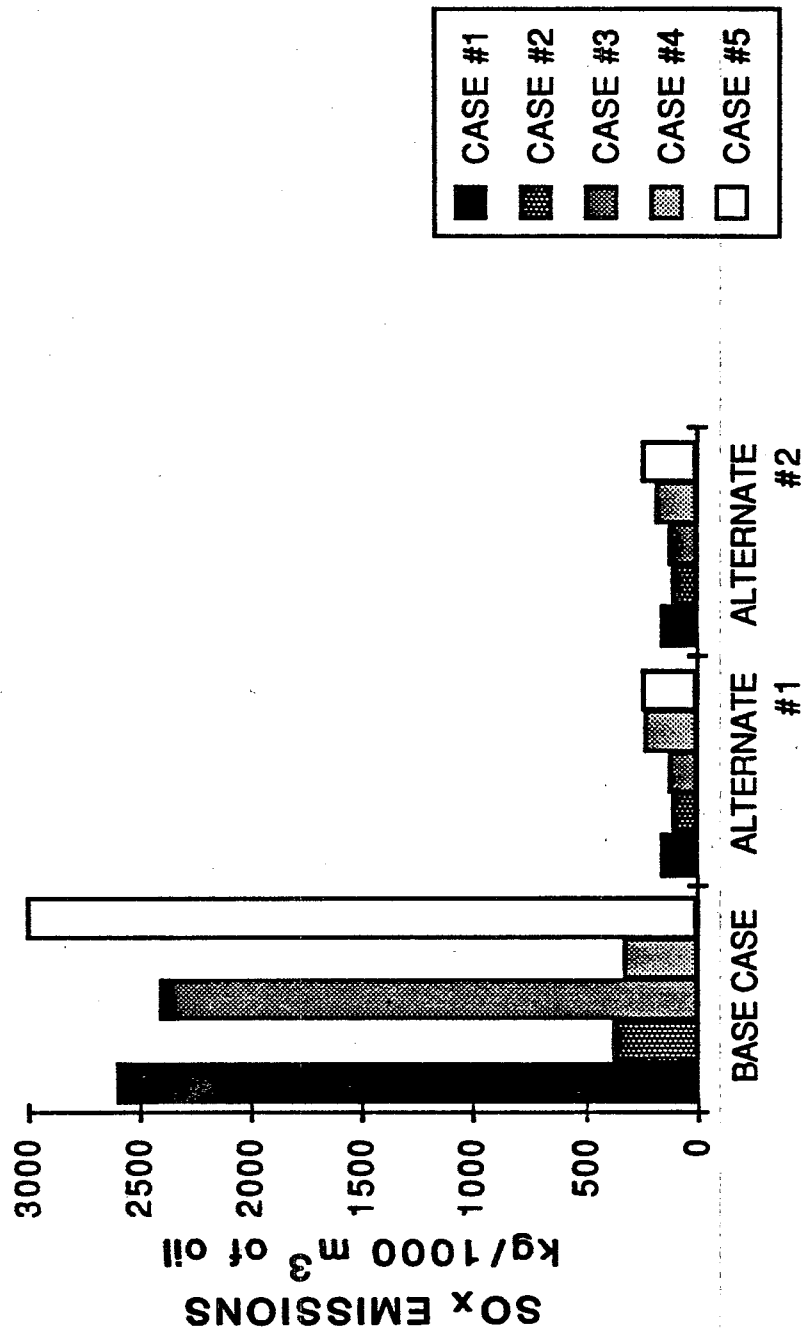


Figure 11.

# PARTICULATE EMISSIONS FOR FIVE CASES

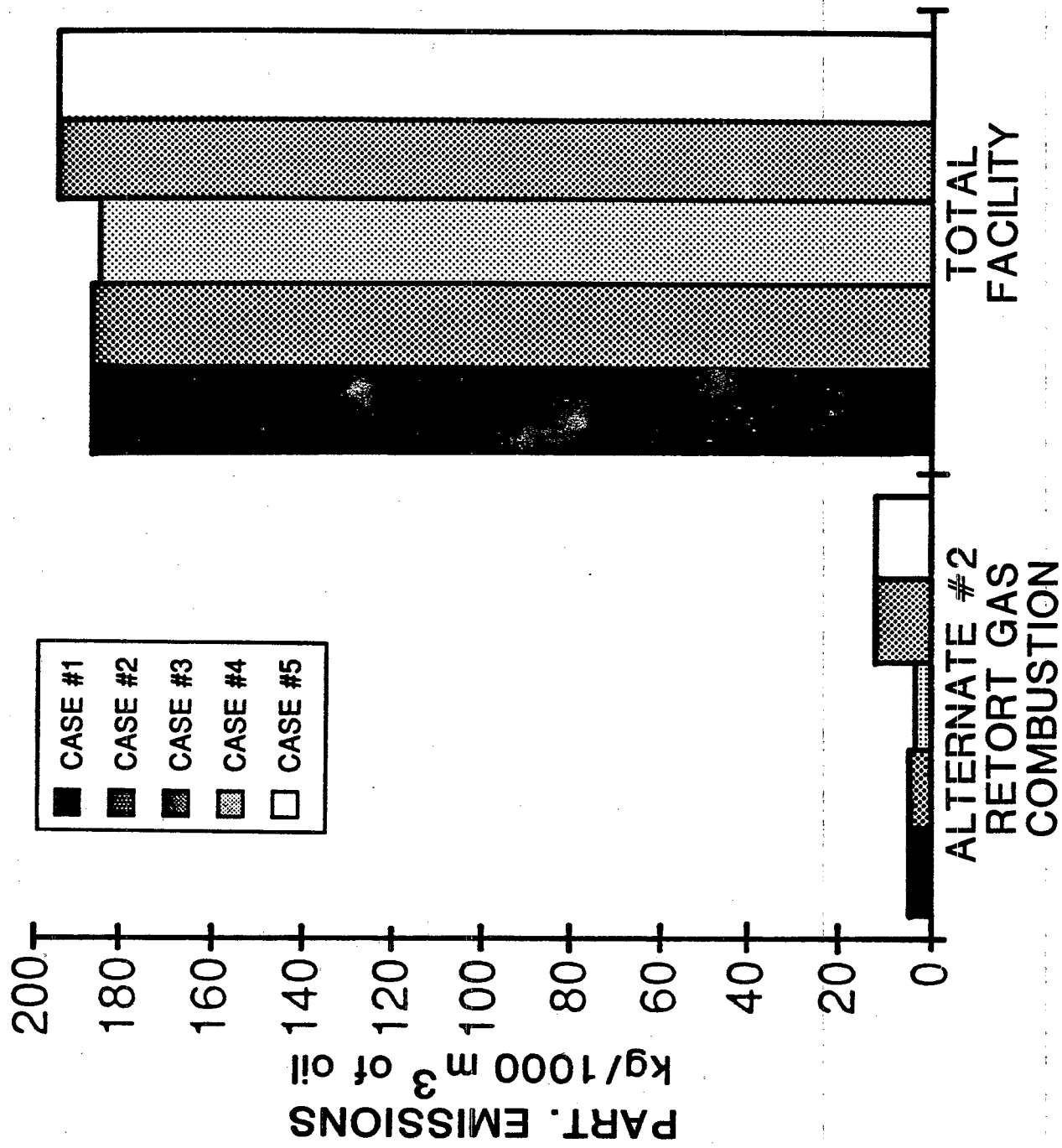


Figure 12.

# NITROGEN OXIDES EMISSIONS FOR FIVE CASES

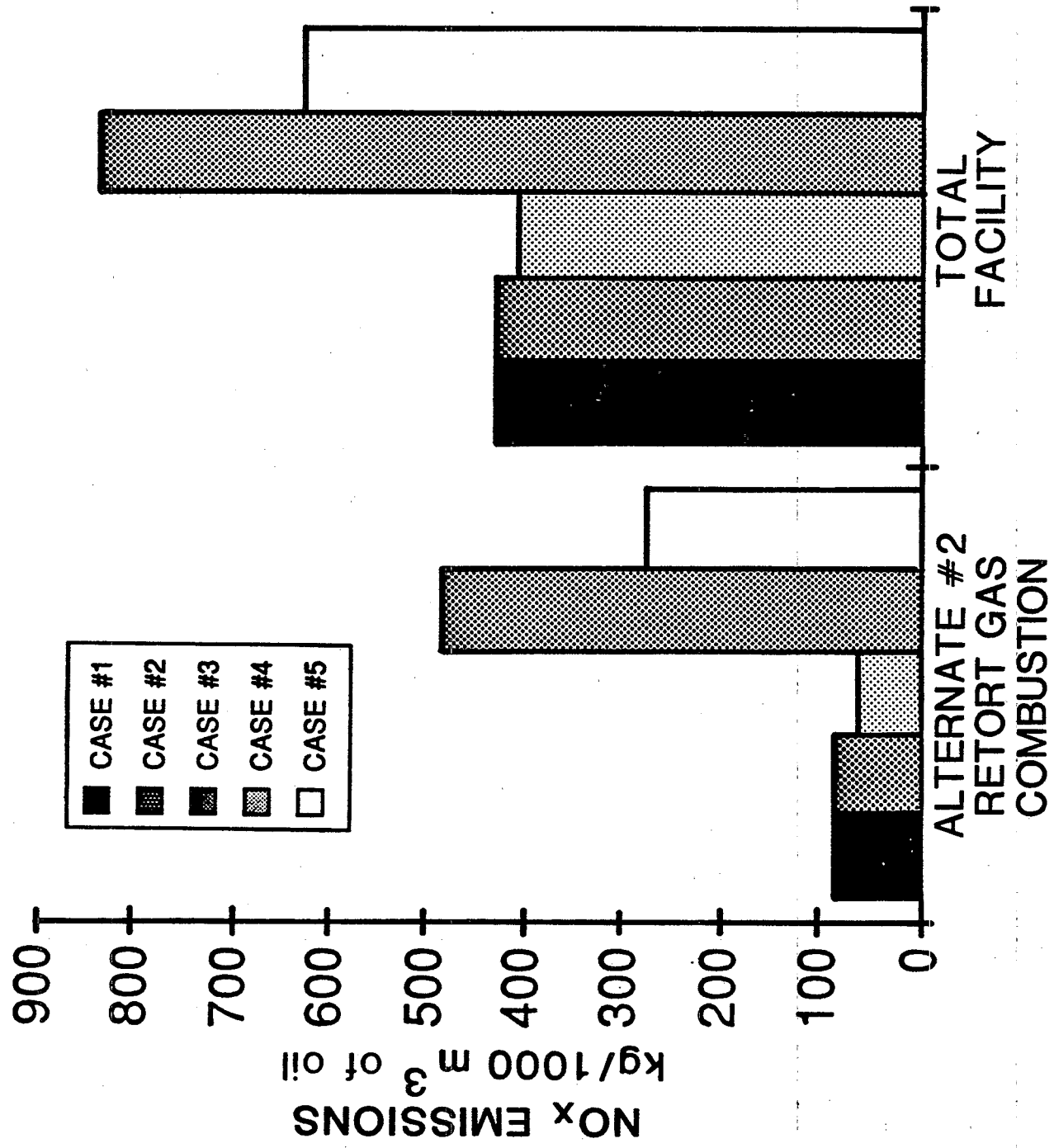


Figure 13.

# SULFUR OXIDES EMISSIONS FOR FIVE CASES

