

16--AIR POLLUTION CONTROL FOR
SYNTHETIC LIQUID FUEL PLANTS

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A. Introduction

1. Organization of the Discussion

In the assessment of the need for new technology for air pollution control in a future synthetic liquid fuel industry, the major steps are the following: (1) description and evaluation of the processes, emissions, and controls that can be used in the production of synthetic liquid fuels from coal and oil shale, (2) modeling the dispersion of pollutants emitted to the atmosphere, (3) comparing calculated ambient concentrations of pollutants with air quality standards that could apply in regions where the plants may be built, and (4) drawing conclusions regarding the adequacy of air pollution control technology for synthetic fuel plants. These steps are amplified in Sections B through E of this chapter, as indicated in the following paragraphs.

Section B identifies the sources of emission of air pollutants from various synthetic fuel processes by unit operation within the process and specifies the emissions that could be expected with best available control applied to each unit. Explicit assumptions about what constitutes the best available control are given and some of the choices that must be made in selecting the control technology to be applied to various unit operations within the process are discussed. Tables are given to summarize the resulting emission characteristics of each of the

processes considered. Two processes for making synthetic crude oil are emphasized: TOSCO II retorting of oil shale and H-Coal liquefaction of western coal.

Section C uses the emission characterization of Section B to specify the source terms for atmospheric dispersion modeling. Reasonable assumptions regarding stack configurations and parameters are combined with meteorological data from energy resource regions in Colorado and Wyoming to calculate ambient concentrations of air pollutants. The calculated values are compared with various ambient air quality standards. Finally, the results of a preliminary sensitivity analysis are presented as an indication of the range of control requirements that could be derived from such calculations.

Section D summarizes the two preceding sections by presenting our best estimates of the percent additional control required to meet the Class II nondegradation standards. These standards are expected to apply in the oil shale and coal regions of Colorado and Wyoming, as well as to other energy resource regions of the western United States.

Section E presents conclusions and recommendations based on this analysis of air pollution control for synthetic liquid fuel plants.

2. Background

The assessment reported is a continuation of SRI work for EPA* in which the environmental implications of the development of solar, geothermal, oil shale, and solid waste energy sources were studied.¹ Phase II of that work focused on determination of the requirements for additional air pollution control for an oil shale industry² and is the

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prototype for the analysis presented here on the broader problem of air pollution control for synthetic liquid fuel plants.

The context for this discussion of air pollution control is established in Chapters 4, 6, and 9 of this report. Chapter 4 on the technology of alternative fuel production is most closely related to the air pollution problems and is referred to for some description of the processes. However, Chapter 6, on maximum credible implementation scenarios, and Chapter 9, on decision making for synthetic fuels, while not referred to explicitly here, help to set the stage for this discussion by indicating the possible magnitude of a major shift to synthetic liquid fuel production.

3. Air Pollution Standards

Standards play a key role in this assessment of air pollution control requirements.

Emission standards regulate the quantities of pollutants that can be emitted to the atmosphere from various specific processes or facilities. Such standards may be expressed as the amount of pollutant allowed per unit weight or volume of the total emission stream or as the amount of pollutant allowed per unit level of operation of the facility. Examples of the former are (1) the Colorado emission standard of 500 parts per million (ppm) of SO_2 relative to the total flue gas emitted from a stack and (2) the so-called "new source performance standard" for municipal incinerators of 0.18 g/m^3 (0.08 gr/SCF^*) of

*Grains per standard cubic foot. One pound equals 7000 grains. A standard cubic foot of any gas is the amount of gas that occupies a cubic foot at a standard temperature and pressure, in this case a temperature of 15°C (60°F) and a pressure of 1 atmosphere.

particulates in the exit flue gas. The latter type of emission standard is expressed in units used for "emission factors," such as pounds of sulfur dioxide (SO_2) released to the atmosphere per ton of copper ore processed in a smelter or kilograms of nitrogen oxides (NO_x) per gigajoule (GJ) of energy consumed in a boiler.

The emission standards referred to in this chapter are among the "new source performance standards" promulgated by EPA. These regulations set maximum emission rates for a number of industrial processes and facilities. "New source" is used to designate the fact that these standards apply only to facilities begun after some date specified in the notice of the standard. When new source performance standards are set by EPA, the nature of the processes employed in the industry and the availability of control measures that can be applied at reasonable costs are taken into account. New source performance standards for industrial boilers that consume solid, liquid, or gaseous fossil fuels are variously referred to in this chapter as power plant emission standards, utility boiler standards, or fossil fuel-fired boiler standards.

Air quality standards regulate the concentration of pollutants found in the "ambient" air that the general population breathes or could breathe. Ambient air is that found in the ordinary environment beyond the plant boundary, usually at ground level. Concentrations of pollutants are expressed either in parts per million (a volume of pollutant to volume of air ratio) or in mass per unit volume. The latter expression is now preferred, and all of the federal ambient air quality standards are expressed in units of micrograms per cubic meter of air ($\mu\text{g}/\text{m}^3$). The atmospheric dispersion model used in this work uses emission rates, which could themselves be compared directly only to emission standards, and calculates from them the ambient air quality, in $\mu\text{g}/\text{m}^3$, at various points in the vicinity of the emission source. These

calculated concentrations can be compared directly to ambient air quality standards.

Ambient air quality standards used in this chapter include:

(1) national primary standards, set by the federal government at concentration levels intended to be low enough to prevent adverse effects on human health, (2) national secondary standards, also set by the federal government acting under the same law, but set at lower levels of concentration intended to prevent economic damage, especially to living plants, (3) state air quality standards, in particular those of Colorado and Wyoming, and (4) three classes of ambient air quality standards intended to prevent significant deterioration of air quality in regions in which air pollutant concentrations are currently well below the national standards.

Standards in the last category are frequently referred to as "nondegradation standards." The specific classes and levels of standards in this category have been promulgated by EPA recently.³ EPA proposed that the states be responsible for designating the clean air regions within their borders as belonging to one of three classes. Ambient air quality standards, expressed as increases in levels of concentrations of air pollutants to be allowed within the region, were set by EPA for each of the three classes. Of the three, Class I is the most strict, intended to keep air quality virtually unimpaired and consistent with very minimal industrial development of the regions so classified. Class II standards are strict but generally not so strict that substantial development is precluded, provided the development includes appreciable effort directed toward air pollution control. Class III standards allow the air quality in a region to meet the national primary or secondary levels, whichever is the strictest.

The complete specification of an ambient air quality standard includes, in addition to a level of concentration, the time interval over which the concentration is to be averaged. Standards mentioned in this chapter involve annual averages, 24-hour averages, and 3-hour averages. To completely specify standards tied to a daily or hourly average, the statement of the standard must also name the number of times per year that the specified level may be exceeded. Thus, the 24-hour or 3-hour levels of concentration are viewed as "worst-case" situations, with worst-case defined as the number of days per year a situation that severe is to be allowed under the standard. All such standards referred to in this chapter are to be exceeded no more than one day per year.

Table 16-1 is a summary of the ambient air quality standards referred to in this chapter. The standards are listed in the order of lenient to strict. Because background concentrations (pollutant levels present in the absence of any industrial activity in a region) must be added to the contributions from synthetic fuel plants for comparisons with all the standards other than Class I and Class II, it is possible that Class II, and perhaps even Class I, standards may not be as strict as a state standard in some cases. For example, due to background levels of SO_2 present in the Piceance Basin of Colorado, it would be easier for an oil shale industry to comply with the Class I nondegradation standard for SO_2 than with the corresponding state standard.

B. Synthetic Liquid Fuel Plants: Processes and Emissions of Air Pollutants

Emissions of air pollutants are estimated for three principal synthetic fuel processes:*

*These and other competitive processes are described and discussed in Chapter 4.

Table 16-1

AMBIENT AIR QUALITY STANDARDS

Standard	Pollutant	Concentration Level for Different Averaging Times ($\mu\text{g}/\text{m}^3$)		
		1-yr	24-hr	3-hr
Federal* primary	Particulates	75	260	--
	SO ₂	80	365	--
	NO ₂	100	--	--
	Hydrocarbons (HC)	--	--	160
Federal* secondary	Particulates	60	150	--
	SO ₂	--	--	1300
Colorado [†] (nondesignated areas)	Particulates	45	150	--
	SO ₂	--	15	--
Wyoming [†]	Particulates	60	150	--
	SO ₂	60	260	1300
	NO ₂	100	--	--
	HC	--	--	160
Class II [‡]	Particulates	10	30	--
	SO ₂	15	100	700
Class I [‡]	Particulates	5	10	--
	SO ₂	2	5	25

*Federal primary and secondary from The Federal Register, quoted in Environment Reporter, The Bureau of National Affairs, Inc. (1975).

[†]Colorado and Wyoming standards from The Federal Register, quoted in Environment Reporter, The Bureau of National Affairs, Inc. (1975).

[‡]Class I and II from The Federal Register, Vol. 39, No. 235, Part III (5 December 1974).

- TOSCO II production of oil from shale
- H-Coal production of oil from coal
- SASOL production of methanol from coal.

As cited earlier (Chapter 4), these processes were selected for study because of the advanced or proven development of the process, the suitability of the product for further refinement into automotive fuels in substantial proportion, and the availability of process data. In addition, data that were available on emissions associated with the Solvent Refined Coal (SRC) and Consol Synthetic Fuel (CSF) coal liquefaction processes have been included for comparison.

The relatively rich shale deposits of the Piceance Basin in Colorado are the source of raw material for the TOSCO II process. The H-Coal process emissions are estimated for two representative coals--a relatively high sulfur midwestern (Illinois No. 6) coal and a low sulfur subbituminous western (Powder River, Wyoming) coal. The data cited for the SRC and CSF processes pertain to the use of a "northwest" coal, similar to the Powder River coal, and a "central" coal, which is similar to the Illinois coal. The SASOL process consumes a low sulfur "western" coal similar to Powder River coal. Two process variations are also considered in the SASOL case: (1) the "design" process in which plant heat demand is met with a fuel gas manufactured from the coal and (2) an alternative process in which the necessary coal is burned directly. The latter process conserves energy but increases emissions.

In each case emissions from the production of electricity needed by the plant are estimated. These emissions are ascribed to the process regardless of plans to purchase the electricity or generate it on-site. However, the ambient concentration modeling in Section C excludes emissions ascribed to generation of electricity.

1. Syncrude from Oil Shale

The process of extracting the organic material from oil shale and of converting and upgrading the material to a suitable product is described in Chapter 4 and the analysis of air pollution control necessary for the TOSCO II process² is summarized here. Also included here are emissions that result from the generation of electricity supplied to the plant. Plans for the first TOSCO II installation by Colony Development Operation⁴ call for purchase of electricity; other installations may generate electricity on-site. In either case the resulting emissions are attributable to the plant. Comparisons with the other synthetic fuels, those derived from coal, will then include emissions from all combustion needed for the plant. In all cases it is assumed that coal is consumed to generate electricity.

In addition, the TOSCO II plant is considered to produce a synthetic crude oil rather than a fuel oil. The difference in product does not have a significant effect on the air pollution expected from the plant. The dominant emissions from the plant are from the ore-preparation system and the pyrolysis and oil recovery unit, and these processes are the same for either product. Emissions from the product-upgrading units could vary with product changes, but these units consume relatively little fuel and therefore are relatively minor contributors to emissions. The crude shale oil must be upgraded to some degree in any case to permit transport by pipeline.

a. Control of Emissions

Emissions of a TOSCO II plant producing 16,000 m³/day (100,000 B/D) of syncrude are summarized in Tables 16-2 through 16-5. Table 16-2 lists emissions attributed to the generation of electricity. Tables 16-3 through 16-5 summarize emissions of each major pollutant

Table 16-2

ELECTRIC POWER GENERATION* EMISSIONS ATTRIBUTABLE TO A TOSCO II
OIL SHALE PROCESSING PLANT
(16,000 m³/day of syncrude)

Type Emission	Emissions Without Control Devices		Control Methods		Emissions Remaining With Best Control	
	Factor (kg/10 ³ kg) †	Rate (g/s)	Device	Efficiency (%)	Factor (kg/GJ) †	Rate (g/s)
Particulates	46.4	1280	Electrostatic precipitator	99.5	0.013	6.4
SO ₂	9.5	260	Flue gas desulfurization	90	0.052	26
NO _x	9	245	None		0.50	245
HC	0.15	4.2	None		0.0083	4.2

*Assumes use of Powder River Coal (see Section B-2).

†Refers to kg of pollutant per 10³ kg of coal burned in the boiler.

‡Refers to kg of pollutant per 10⁹ joules (about 10⁶ Btu) of heat input to the boiler.

Table 16-3

PARTICULATE EMISSIONS FOR TOSCO II OIL SHALE PROCESSING PLANT
(16,000 m³/day)

System	Emissions Without Control		Control Methods		Emissions Remaining With Best Control	
	Loading (mg/m ³)	Amount (g/s)	Device	Efficiency (%)	Loading (mg/m ³)	Amount (g/s)
Ore preparation						
Primary crusher	2,300	540	Baghouse	98.0	46	11
Final crusher	26,000	7,400	Baghouse	99.8	46	13
Fine-ore storage	21,000	1,600	Baghouse	99.8	46	3.3
Pyrolysis and oil recovery						
Raw shale preheat	16,000	18,000	Venturi scrubber	99.7	46	53
Steam superheater--ball stacks	5,900	1,400	Cyclone and Venturi scrubber	99.2	46	11
Processed shale moisturizer	8,200	970	Venturi scrubber	99.4	46	5.6
Product-upgrading						
Hydrogen unit	9	2.7	None		9	2.7
Naphtha hydrogenation	7	0.05	None		7	0.05
Gas oil hydrogenation						
Feed heater	7	0.23	None		7	0.23
Fired reboiler	7	0.20	None		7	0.20
Delayed coker	9	0.39	None		9	0.39
Utility boilers	50	2.5	None		50	2.5

Table 16-4

SO₂ EMISSIONS FOR TOSCO II OIL SHALE PROCESSING PLANT
(16,000 m³/day)

System	Emissions Without Control Devices		Control Method		Emissions Remaining With Best Control	
	Factor (kg/GJ)	Amount (g/s)	Device or Other Method	Efficiency (%)	Factor (kg/GJ)	Amount (g/s)
Pyrolysis and oil recovery						
Raw shale preheat	27	295	Treated fuels†	--	24	255
Steam superheater--ball stacks	6.0	5.3	Treated fuels	--	6.0	5.3
Product upgrading						
Hydrogen unit	22	81	Treated fuels	--	22	81
Naphtha hydrogenation	22	1.3	Treated fuels	--	22	1.3
Gas oil hydrogenation						
Feed heater	6.0	1.8	Treated fuels	--	6.0	1.8
Fired reboiler	6.0	1.5	Treated fuels	--	6.0	1.5
Delayed coker	22	11	Treated fuels	--	22	11
Utility boilers	43	23	Treated fuels†	--	34	19
Sulfur plant	4-5,000*	320	Tail-gas scrubber	95	250*	16

*Units for sulfur plant emission factor--ppm by volume.

†Treated fuels include fuel oil meeting federal new source performance standards for power plants instead of fuel oil planned by Colony.

Table 16-5

NO_x EMISSIONS FOR TOSCO II OIL SHALE PROCESSING PLANT
(16,000 m³/day)

System	Emissions Without Control Devices		Control Methods	Emissions Remaining With Best Control	
	Factor (kg/GJ)	Amount (g/s)		Factor (kg/GJ)	Amount (g/s)
Pyrolysis and oil recovery					
Raw shale preheat	107	1,160	Treated fuels*	28	295
Steam superheater--ball stacks	39	33	None	39	33
Product upgrading					
Hydrogen unit	37	135	None	37	135
Naphtha hydrogenation	37	2.3	None	37	2.3
Gas oil hydrogenation					
Feed heater	39	11	None	39	11
Fired reboiler	39	9.2	None	39	9.2
Delayed coker	37	19	None	37	19
Utility boiler	210	114	Treated fuels*	13	6.9

*Treated fuels include fuel oil meeting federal new source performance standards for power plants instead of fuel oil planned by Colony.

from individual subsystems in the plant. The only other substantial emission is 76 g/s of hydrocarbons from the raw shale preheat system. An incinerator controls hydrocarbon emissions to this level.

The final column for each table lists the estimate of emissions remaining after application of "best control." The assumptions leading to establishment of standards for best control are:

- Dust loading controlled to a level not exceeding 46 mg/m³, equivalent to 0.02 gr/ACF.*
- Use of treated fuels, including use of a fuel oil meeting the federal new source performance standards for oil fired boilers, to control levels of SO₂ and NO_x.
- Sulfur plant emission of SO₂ controlled to a level of 250 ppm by volume.
- Electric power plant emission of particulates controlled 99.5 percent and emission of SO₂ controlled 90 percent.

A principal uncertainty in the estimates is the oil originally intended to fuel the plant. Other captive fuels planned for use have relatively lower emissions than the fuel oil in all categories.³ Colony has indicated that this fuel oil will be subjected to further hydrotreatment, reducing both sulfur and nitrogen content, when it is necessary to insure that the plant meets relevant emission or ambient standards.⁵ This procedure is said to be expensive, although relatively less costly than flue gas desulfurization. Until experience is gained with the

*Grains per actual cubic foot; at the elevated temperatures involved, an actual cubic foot is considerably less dense than a cubic foot at normal temperatures and pressures.

process in its given environment, the present estimates serve best for comparison with other synthetic fuel processes.

A recent discovery⁵ at Colony, not yet fully confirmed, adds another element of uncertainty. It appears that SO₂ emissions in the raw shale preheat subsystem (Table 16-4) may be effectively lowered by contact with materials present in the raw shale. The effect on emission levels would be significant since most of SO₂ is emitted from this unit. The tentative finding is that as much as two-thirds of the expected SO₂ may be removed from the raw shale preheat exhaust.

b. Options for Further Control

Later sections of this chapter indicate that further control of particulates and SO₂ may be required.

It is likely that improved control of particulates can be obtained. Principal sources are shale dust from the ore-preparation system and the raw shale preheat subsystem. Where shale dust is controlled, estimates of efficiency were derived using the quantities of sludge disposed to estimate loadings before control. This procedure overestimates efficiency since coarse particles are trapped by gravity to some extent before final collection. Since no measure of the proportion of fine particulates was available, the estimated emissions must be considered an upper limit. In addition to this consideration, the "best control" level used here may be conservative, depending on the proportion of fine particulates present.

Flue gas desulfurization remains an option for further control of the SO₂ levels. The economics of this process compared with hydrotreatment of the fuel oil, at the time of plant construction and later, would determine the selection.

c. Other Processes

In general, the estimates of emissions for ore-preparation systems and product upgrading systems associated with other surface retorting processes would be similar to TOSCO II. The emissions from a different retorting module could vary significantly, especially in dust emissions. The TOSCO II estimates would probably be highest of all processes under consideration with regard to dust from this module. Other emissions would depend primarily on similarity of fuels. Further discussion of these considerations may be found in Reference 2.

2. Syncrude from Coal

In estimating the emissions to the atmosphere from the operation of an H-Coal plant* producing 16,000 m³/day (100,000 B/D) of syncrude two cases are considered: (1) processing Wyoming Powder River sub-bituminous coal, and (2) processing Illinois No. 6 bituminous coal. The characteristics of these coals are given in Table 16-6.

a. Control of Emissions

Tables 16-7 and 16-8 contain a summary of the emissions for an H-Coal plant processing each type of coal. In contrast to TOSCO II, a detailed breakdown of the fuel consumed in each major unit of the process is not available. Only two fuels are consumed--a captive fuel gas and coal. Emission factors for natural gas⁷ were used for the fuel gas.

For Illinois coal, adequate quantities of fuel gas are expected to provide all fuel needed for the process. Coal is combusted

*H-Coal process is described in Chapter 4 and Reference 6.

Table 16-6

CHARACTERISTICS OF REPRESENTATIVE
WESTERN AND EASTERN COALS

	Ultimate Analysis	
	(% by wt)	
	Wyoming Powder River Subbituminous Coal	Illinois No. 6 Bituminous Coal
Moisture	33	10
Ash	5.8	9
Carbon	45.7	62.7
Hydrogen	3.2	4.8
Oxygen	11.1	8.9
Sulfur	0.5	3.5
Nitrogen	0.7	1.1
 Total	 100.0	 100.0
 Higher heating value		
MJ/kg (Btu/lb)	18(7800)	26(11,000)

only to provide the electricity required. For Powder River coal, the fuel gas evolved in the process is not adequate to supply fuel needs, and coal is used to make up the difference as well as to produce electricity.

The emission factor for coal dust from the dryers is a pessimistic choice from the range of factors⁷ that are likely. Removal of essentially all moisture is specified for the process.

Control of emissions from coal combustion,⁸ using an electrostatic precipitator and flue gas desulfurization, is estimated at 99.5 percent for particulates and at 90 percent for SO₂. While the estimate for SO₂ removal may be controversial, the best independent judgment at present is that it can be met.⁸ A high performance Venturi

Table 16-7

EMISSIONS FOR H-COAL LIQUEFACTION OF POWDER RIVER COAL
(16,000 m³/day)

Emissions Without Control Devices		Control Methods		Emissions Remaining With Best Control		
Type	Factor	Rate (g/s)	Device	Efficiency (%)	Loading	Rate (g/s)
Coal drying						
Dryer exhaust	12.5 kg/10 ³ kg*	4200	Multiple cyclones and Venturi scrubber	99.0	36.7 mg/m ³ †	44
Fuel combustion (coal)	46.4 kg/10 ³ kg	1325	Electrostatic precipitator	99.5	12.8 g/GJ	6.6
	9.5	271	Flue gas desulfurization	90	52.4	27.1
	9	237	None		496.	257
	0.15	4.3	None		8.3	4.3
Steam reformer						
Fuel combustion (gas)	290 kg/10 ⁶ m ³	5.8	None		6.2	5.8
	9.2	0.19	None		0.2	0.19
	3700	74	None		81.	74
	48	1.0	None		1.	1.0
Plant						
Fuel combustion (coal)	46.4 kg/10 ³ kg	2340	Electrostatic precipitator	99.5	12.8	11.7
	9.5	479	Flue gas desulfurization	90	52.4	47.9
	9.	454	None		496.	454
	0.15	7.6	None		8.3	7.6
Fuel combustion (gas)	290 kg/10 ⁶ m ³	1.3	None		6.2	1.3
	9.2	0.04	None		0.2	0.04
	3700	17	None		81.	17
	48	0.2	None		1.	0.2
Sulfur plant	5000 ppm (vol)	320	Tail-gas scrubber	95	250 ppm (vol)	16.
Electricity						
Fuel combustion (coal)	46.4 kg/10 ³ kg	1079	Electric precipitator	99.5	12.8 g/GJ	6.4
	9.5	221	Flue gas desulfurization	90	52.4	22.1
	9.	209	None		496.	209
	0.15	3.5	None		8.3	3.5

*2.87 gr/dSCF (grains per dry standard cubic foot).
†0.03 gr/dSCF.

Table 16-8

EMISSIONS FOR H-COAL LIQUEFACTION OF ILLINOIS COAL
(16,000 m³/day)

Source Unit	Emissions Without Control Devices			Control Methods		Emissions Remaining With Best Control	
	Type	Factor	Rate (g/s)	Device	Efficiency (%)	Loading	Rate (g/s)
Coal drying Dryer exhaust	Particulates	12.5 kg/10 ³ kg*	4520	Multiple cyclones with Venturi scrubber	99.8	43.3 mg/m ³ †	10.7
	Particulates	290 kg/10 ⁶ m ³	0.69	None		6.0 g/GJ	0.69
	SO ₂	9.2	0.02	None		0.2	0.02
	NO _x	3700	8.8	None		76.4	8.8
	HC	48	0.11	None		1.0	0.11
Steam reformer Fuel combustion (gas)	Particulates	290 kg/10 ⁶ m ³	2.19	None		6.0	2.19
	SO ₂	9.2	0.07	None		0.2	0.07
	NO _x	3700	28.0	None		76.4	28.0
	HC	48	0.36	None		1.0	0.36
Plant Fuel combustion (gas)	Particulates	290 kg/10 ⁶ m ³	9.47	None		6.0	9.47
	SO ₂	9.2	0.30	None		0.2	0.30
	NO _x	3700	121	None		76.4	121
	HC	48	1.57	None		1.0	1.57
Sulfur plant	SO ₂	5000 ppm (vol)	1370	Tail-gas scrubber	95	250 ppm (vol)	68.7
Electricity Fuel combustion (coal)	Particulates	72 kg/10 ³ kg	1080	Electrostatic precipitator	99.5	14.1 g/GJ	5.4
	SO ₂	66.5	998	Flue gas desulfurization	90	260	99.8
	NO _x	9	135	None		351.7	135
	HC	0.15	2.25	None		5.9	2.25

*12.68 gr/dSCF (grains per dry standard cubic foot).
†0.03 gr/dSCF.

scrubber following multiple cyclones is likely to be necessary^{8,9} to meet the proposed federal standard⁹ for coal drying--70 mg per dry normal cubic meter (0.03 gr/dSCF).^{*} The efficiencies shown necessary to meet this standard are judged to be reasonable.^{8,9}

Sulfur plant emissions were calculated from the sulfur input and output rates. The efficiency of the scrubber applied to the tail-gas from the sulfur plant was estimated at 95 percent, a commonly achieved figure.

Combustion calculations were performed for all fuels (the fuel gas has a different composition for the different coals) to determine the flow rates and the set of stack parameters used in Section C to calculate the ambient air quality in the plant vicinity. Coal dryer flow rates were determined from coal moisture and typical exhaust temperatures.

The plant processing Illinois coal was assumed to be at sea level, while the Powder River elevation, 1230 m (4000 ft), corresponds to a pressure of 87.4 kPa (25.84 in. Hg).

b. Options for Further Control

The level of control indicated above is estimated in later sections to be adequate. Should further control become necessary, particulate emission from the coal dryers would be closely examined. Some improvement, especially for Powder River coal, seems possible with the same type of equipment. Improvement in flue gas desulfurization would bring about the best improvement in SO₂ levels. An alternative would be to replace at least part of the coal with a cleaner fuel.

*Grains per dry standard cubic foot.

c. Other Processes

Emissions associated with other coal conversion processes have been estimated by others.¹⁰ Total emissions from SRC and CSF plants* are given in Table 16-9 for comparison with other synthetic fuel processes. Emissions are shown for central coal (25 MJ/kg, 11.3 percent ash, 3.7 percent sulfur) and northwest coal (20 MJ/kg, 6 percent ash, 0.5 percent sulfur). These are very similar to Illinois No. 6 and Powder River coals, respectively (Table 16-6).

Table 16-9

CONTROLLED EMISSIONS[†] FOR SRC AND CSF
COAL LIQUEFACTION PLANTS
(16,000 m³/day)

<u>Process and Operation</u>	<u>Pollutant</u>	<u>Emission Rate by Coal Type</u> (g/s)	
		<u>Central</u>	<u>Northwest</u>
SRC			
Combustion and drying	Particulates	34	35
Combustion	SO ₂	97	16
	NO _x	900	900
	HC	2.9	2.9
Sulfur recovery	SO ₂	203	32
CSF			
Combustion and drying	Particulates	24	21
Combustion	SO ₂	257	44
	NO _x	550	540
	HC	2.7	2.5
Sulfur recovery	SO ₂	64	14

*SRC and CSF processes are described in Chapter 4.

[†]Includes emissions from electricity generation.

The level of control of emissions assumed for Table 16-9 was similar to that used for H-Coal. Coal dryer dust was controlled to the 99.85-percent level with a Venturi or Baghouse following the multiple cyclones, and sulfur plant tail-gas scrubbing was 95 percent effective. The SRC plant derives 92 percent of fuel demand from a captive fuel gas and the remainder from a product fuel oil. Since the sulfur content of the fuel gas is negligible, and the fuel oil contains only 0.28 percent of the sulfur level of the feed coal, no further control is imposed on the SRC plant. The CSF plant fuel needs are met 84 percent with fuel gas containing 0.4 percent of the sulfur level of the feed coal; the remaining 16 percent fuel needs are satisfied with coal. As above, an electrostatic precipitator plus flue gas desulfurization control emissions from the burning of coal--particulates are reduced 99.5 percent and SO₂ is reduced 90 percent (95 percent was assumed in Reference 10--this was adjusted to give the data shown in Table 16-9). Emissions associated with generation of the required electricity are included in Table 16-9.

3. Methanol from Coal

A general description of the process for producing methanol from coal is given in Chapter 4 with the SASOL process described in more detail in Reference 11. In estimating emissions to the atmosphere resulting from the operation of a SASOL plant producing 16,000 m³/day (100,000 B/D) of methanol, two cases are considered: (1) operation of the plant as designed¹¹ using a fuel gas manufactured from the coal, and (2) operation of the plant burning the coal directly to obtain necessary process steam and electric power. A western coal yielding 20 MJ/kg (8700 Btu/lb) and containing 19 percent ash and 0.69 percent sulfur is assumed for both cases. This coal is of somewhat lower quality,

in terms of ash and sulfur content, than the Powder River coal (Table 16-6).

a. Control of Emissions

Tables 16-10 and 16-11 present emissions for a SASOL plant processing coal to methanol for each fuel scheme. In both cases all fuel is consumed in a steam and power generation plant, and all purge gases (those evolved as a byproduct) are consumed. For the case considered in Table 16-10, part of the coal input is gasified to produce a fuel gas that is cleaner burning than the coal. The efficiency of this conversion is about 67 percent, leading to a total coal input rate of 35.4×10^6 kg (39,000 tons) per day. When the coal is burned directly (Table 16-11), the total coal input rate is 31.6×10^6 kg (34,800 tons) per day for the same methanol output.

Emission factors for natural gas⁷ were used for both the purge gas and the manufactured fuel gas with one exception. The known sulfur content¹¹ of the manufactured fuel gas, in the form of H₂S, was assumed to be entirely converted to SO₂ during combustion. Sulfur content of the purge gas was specified¹¹ to be negligible, so that the factor for natural gas⁷ was used. Emission factors for the coal⁷ were calculated from the properties specified above. Since coal drying is not specified for this process, no special dust emissions are listed for this potential source. The uncontrolled emission rate for the sulfur plant was calculated from the specified¹¹ H₂S in the tail-gas stream. This flow was adjusted in Table 16-11 to account for deletion of manufactured fuel gas.

No controls are added for the relatively clean-burning gas. Controls for the coal burning are analogous to those imposed for the liquefaction processes (see Section B-2). A reduction in

Table 16-10

EMISSIONS FOR SASOL METHANOL PLANT USING MANUFACTURED FUEL GAS
(16,000 m³/day)

Source	Emissions Without Control Devices			Control Methods			Emissions Remaining With Best Control	
	Type	Factor	Rate (E/s)	Device or Other Method	Device Efficiency (%)	Loading	Rate (g/s)	
Combustion Purge gas	Particulates	290 kg/10 ⁶ m ³	4.6	None		7.3 g/GJ	4.6	
	SO ₂	9.2	0.1	None		0.16	0.1	
	NO _x	3700	60	None		95	60	
	HC	48	0.8	None		1.3	0.8	
Manufactured fuel gas	Particulates	290	16	None		7.3	16	
	SO ₂	9000	151	Treated fuel		71	151	
	NO _x	3700	202	None		95	202	
	HC	48	2.7	None		1.3	2.7	
Sulfur plant	SO ₂	1960 ppm (vol)	194	Tail-gas scrubber	95	250 ppm (vol)	9.7	

Table 16-11

EMISSIONS FOR SASOL METHANOL PLANT USING COAL FOR FUEL
(16,000 m³/day)

Source	Emissions Without Control Devices			Control Methods		Emissions Remaining With Best Control	
	Type	Factor	Rate (g/s)	Device	Efficiency (%)	Loading	Rate (g/s)
Combustion Purge gas	Particulates	290 kg/10 ⁶ m ³	4.6	None		7.3 g/GJ	4.6
	SO ₂	9.2	0.1	None		0.16	0.1
	NO _x	3700	60	None		95	60
	HC	48	0.8	None		1.3	0.8
Coal	Particulates	154 kg/10 ³ kg	13960	Electrostatic precipitator	99.5	39	70
	SO ₂	13.1	1190	Flue gas desulfurization	90	66	119
	NO _x	9	816	None		450	816
	HC	0.15	14	None		7.7	14
Sulfur plant	SO ₂	1960 ppm (vol)	134	Tail-gas scrubber	95	250 ppm (vol)	6.7

particulates^b of 99.5 percent is expected for an electrostatic precipitator followed by flue gas desulfurization, and a reduction of SO₂ level^b is expected to be about 90 percent. The tail-gas scrubber should be 95 percent effective in removing sulfur from the tail-gas stream of the sulfur plant.

b. Options for Further Control

The clearest option for better control is to select the process using the manufactured fuel gas. The SO₂ levels are similar but the other emissions are considerably lower. The cost in coal feed is about 12 percent of the total feed rate. Another option would be to treat the fuel gas for further sulfur removal. The SO₂ loading from the fuel gas combustion is already comparable to the scrubbed flue gas from the coal.

4. Summary

Table 16-12 summarizes the total emissions from each processing plant and feedstock combination considered. These values include the emissions attributed to generation of electricity needed for each plant. However, the values given in parentheses in Table 16-12 exclude the generation of electricity, and are used in Section C to model the ambient concentrations for those processes. Electricity is assumed to be generated off-site for the processes modeled.

C. Atmospheric Dispersion Modeling

Requirements for additional control, beyond the levels taken to represent best available control in the preceding section, are derived by comparing ambient concentrations of air pollutants that result from synthetic fuel plant emissions to ambient air quality standards that

could apply in the vicinities of the plants. This section describes the atmospheric dispersion modeling used to calculate ambient concentrations from emission levels and presents the results of those calculations. These results are displayed later in this section as possible control requirements. A subset of these results forms the basis for estimates of the applicable control requirements (Section D).

Table 16-12

SUMMARY OF EMISSIONS FROM ALTERNATIVE SYNTHETIC FUEL PLANTS EMPLOYING BEST AVAILABLE CONTROL*

	Total Emissions Including Electricity [†]			
	(g/s)			
	Particulates	SO ₂	NO _x	HC
TOSCO II	109(103)	420(394)	761(514)	80(76)
H-Coal--Powder River	75(69)	113(91)	1011(802)	17(13)
H-Coal--Illinois No. 6	28	169	293	4
SRC--Northwest	35	48	900	3
SRC--Central	34	300	900	3
CSF--Northwest	21	58	540	3
CSF--Central	24	321	550	3
SASOL--Fuel gas	21	161	262	4
SASOL--Coal	75	126	876	15

*Plant size taken to be 16,000 m³/day (100,000 B/D).

†Numbers in parentheses exclude emissions attributed to generation of electricity.

1. General Principles

Atmospheric dispersion modeling requires suitable specification of input data describing both the sources of emission of air pollutants and the region into which the pollutants are emitted. The model

employed here requires a standard set of data to characterize sources: the heights, diameters, temperatures, gas flow rates, pollutant emission rates, and positions of the stacks comprising the source of emissions. It also requires readily available meteorological data. (Appropriate data for source characterization are shown in Tables 16-13 and 16-16 and Figures 16-1 and 16-6 later in this section.) Information on the emission source is combined with information on the site in question to form an estimate of the ambient air quality. The required data are available for sites near but not precisely at western oil shale and coal regions.

The model used here for calculation of air pollutant concentrations is the Climatological Dispersion Model (CDM),^{12,13} which is a computerized model that permits calculation of seasonal or annual average pollutant concentration patterns resulting from stationary point sources and area sources. The fundamental physical assumption of the model is that the steady-state spatial distribution of pollutant concentration from a continuously emitting point source is given by the Gaussian plume formula. It is assumed that meteorological conditions over short periods of time (of the order of one hour) can be regarded as steady-state and that these conditions can be approximated with a constant and spatially uniform wind vector for the entire area.

Gaussian plume assumption is used when there are no restrictions on vertical diffusion. When vertical diffusion is restricted to a finite mixing depth, a uniform vertical concentration distribution is assumed at distances a few kilometers downwind.

Equations for the long-term average concentrations due to point and area sources are weighted according to a frequency function to account for the variability of meteorological conditions. These empirical functions express the observed joint frequency of occurrence of various classes of wind direction, wind speed, and a stability.

Integration of the formulac over the area and point sources describes the simulated concentration at selected location for a certain set of meteorological conditions. These concentrations, taken together with the frequency of occurrence of each combination of conditions, produce the climatologically averaged spatial distribution of concentration.

The CDM program used in this study assumes that the pollutant be properly simulated by a single wind vector; thus topographic influences of complex terrain are not currently incorporated into the dispersion model. Topographical features of the regions modeled for oil shale production in Colorado (Section C-2) and coal liquefaction in Wyoming (Section C-3) are discussed below.

For comparisons with ambient air quality standards the concentration of air pollutants are calculated here using averaging times that fit the various standards. Four air pollutants are included: particulates, sulfur dioxide (SO_2), oxides of nitrogen (NO_x) and hydrocarbons (HC). The time periods involved are: annual averages for particulates, SO_2 , and NO_x ; 24-hour averages for particulates and SO_2 ; and a 3-hour average for HC. Since photochemical interactions with NO_x and HC are not considered, no decay with time of NO_x and HC concentrations is assumed. Decay of SO_2 is accounted for in model calculations by an exponential decay term having a 3-hour half life.

The results of the dispersion modeling are compared with federal and state ambient air quality standards. Emissions and ambient concentrations of NO_x (combining both NO and NO_2) are expressed as NO_2 equivalent and compared to the NO_2 standard. This amounts to a worst-case assumption for NO_2 in that NO_x emissions are assumed to consist entirely of NO_2 . However, as mentioned above, no photochemical atmospheric dispersion model has been used, and therefore we have not addressed the possibility that photochemical oxidant formation could be the most significant limit on emissions of NO_x and HC.

2. Modeling a TOSCO II Oil Shale Plant

a. Characterization of Emission Source

Table 16-13 and Figure 16-1 present the emission source characteristics required as part of the inputs to the CDM. The emission rates given in Table 16-13 are those derived and explained in Section B. Figure 16-1 shows a possible configuration of stacks comprising the specific emission sources within the 16,000-m³/day (100,000-B/D) oil shale plant, based on the description of a 8,000-m³/day (50,000-B/D) TOSCO II oil shale complex given by Colony Development Operation.⁴ Radical changes in the assumed configuration could result in concentrations somewhat different from those calculated here.

b. Characterization of Oil Shale Region

Meteorology and topography will affect the ambient air quality from a given emission source. The oil shale regions considered here are the Piceance Basin in western Colorado and the Uinta Basin in eastern Utah. Because the oil shale deposits developed first are most likely to be in or near the Piceance Basin, that region is emphasized.

(1) Topography.* The major oil shale area of the Piceance Basin lies on the Roan Plateau, bounded by steep escarpments in all directions. The land surface of the region has been shaped by erosion into valleys and ridges oriented in the north and northeasterly directions. The difference in elevation from ridge to valley floor ranges from 62 to 185 m (200 to 600 ft), and most of the valleys are

*The information contained in this section was extracted from Reference 14.

Table 16-13

STACK PARAMETERS AND EMISSION RATES FOR A 16,000-m³/D
(100,000-B/D) TOSCO II PLANT WITH EMISSIONS CONTROLLED*

Location†	Description of Unit	Flow Rate‡ (all stacks) (m ³ /s)	Temp. (°C)	No. of Stacks	Stack Height (m)	Stack Diameter (m)	Gas Exit Velocity (m/s)	Emissions (all stacks) (E/S)			
								Particulates	SO ₂	HIC	NOx
1	Hydrogen unit	317	260	2	30.5	3.0	21.7	2.7	81.0	--	135.4
2	Naphtha hydrogenation	7	427	1	24.4	0.9	10.8	0.05	1.3	--	2.3
3	Gas oil hydrogenation: feed heater	36	427	2	24.4	1.8	6.8	0.23	1.8	--	10.8
4	Gas oil hydrogenation: fired reboiler	31	427	1	24.4	2.1	8.6	0.20	1.5	--	9.1
5	Sulfur plant	30	38	1	76.2	1.5	16.6	--	16.1	--	--
6	Delayed coker	45	260	1	24.4	1.8	17.2	0.39	11.3	--	18.9
7	Steam superheater--ball stack	244	54	12	76.2	1.8	7.8	11.1	5.3	--	33.6
8	Raw shale preheat	1160	54	12	76.2	4.0	7.8	52.8	257.0	75.6	297.0
9	Processed shale moisturizer	119	91	12	12.2	1.2	8.4	5.6	--	--	--
10	Primary crusher	235	16	2	15.2	2.4	25.2	10.8	--	--	--
11	Final crusher	283	16	20	15.2	1.2	12.1	13.1	--	--	--
12	Fine ore storage	76	16	2	15.2	1.5	20.6	3.3	--	--	--
13	Utility boilers	49	260	4	15.2	1.2	10.8	1.5	18.6	--	6.9

*Assumed best available control as specified in Section B of this chapter.

†Location refers to Figure 16-1.

‡To convert to ACFM (actual cubic feet per minute), multiply by 2120.

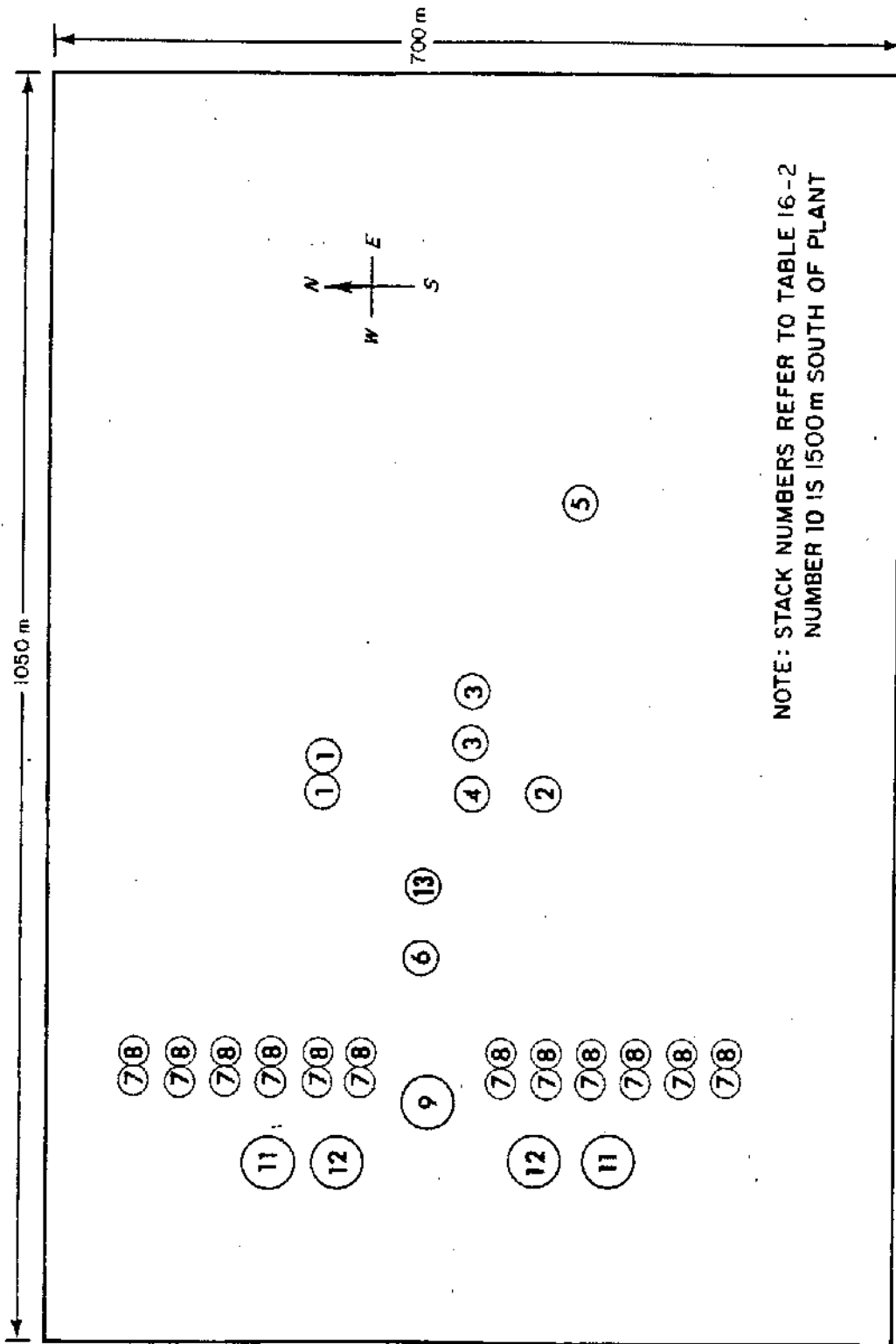


FIGURE 16-1. TOSCO II PLANT CONFIGURATION

narrow and steep sided. Land elevations above mean sea level (MSL) range from about 1600 m (5250 ft) near the White River to about 2800 m (9000 ft) on southern ridge crests.

The Uinta Basin of Utah is a depression bounded by the Uinta and Wasatch Mountains, the Roan Cliffs, and the cliffs west of the Douglas Creek Arch. Land features include rough mountains and flat valleys, with deep gulleys and rock-capped ridges. Elevations range from 1400 m (4600 ft) to more than 2500 m (8000 ft) MSL.

In general, these steep-sided valleys are unsuitable locations for plant sites. Moreover, from the point of view of minimizing pollution potential, oil shale processing facilities should be located on plateau, rather than valley sites.¹⁶ The evidence for the necessity of such location is sufficiently compelling that the dispersion modeling reported here is based on the assumption that the oil shale plants will be located on plateau sites. If an oil shale plant should be located in a narrow valley, the actual concentrations of pollutants will be higher than those calculated by the CDM. However, if the facility is located on a plateau or in a broad valley, as Colony plans for its first plant, the dispersion model will adequately predict concentration patterns.

(2) Meteorology. The meteorological data required for application of the CDM are not available within the oil shale region. Therefore, annual averages were calculated from frequency distributions of meteorological conditions observed at Grand Junction, Colorado, and Salt Lake City, Utah because these were the closest weather stations recording sufficient data. These distributions are the output of the National Climatic Center's* STAR computer program. However, the wind

*U.S. Department of Commerce, National Oceanic and Atmospheric Administration, Environmental Data Service, National Climatic Center, Federal Building, Asheville, N.C. 28801.

data for three stations in the oil shale region show that the differences in the wind direction frequency distributions between any two of these stations are at least as great as the differences between Grand Junction and any of these stations.² Therefore we have used Grand Junction meteorology for calculations of air pollutant concentrations expected in the Piceance Basin. All of the annual average calculations presented here are based on Grand Junction meteorology. Some other results based on Salt Lake City meteorology are presented in an earlier SRI report.² Sensitivity to meteorology is discussed below in Section C-5.

Twenty-four hour averages and 3-hour averages were calculated using the assumption that worst-case meteorological conditions prevailed. Statistical weather records indicate that neutral atmospheric stability and a light wind of 1.5-m/s occur for 24 hours or longer in the oil shale region an average of 15 days per year. These conditions have been shown to be representative of worst-case conditions in the oil shale region and do not involve use of Grand Junction or Salt Lake City meteorological data. The CDM was used to compute the 24-hour and 3-hour averages for various wind directions, assuming 100 percent frequency of occurrence of neutral stability and 1.5-m/s winds.

c. Results of Dispersion and Site Modeling

Pollutant dispersion patterns for a 16,000-m³/day (100,000 B/D) TOSCO II plant were calculated using the emission source characteristics given in Table 16-13 and Figure 16-1 and the characteristics of possible oil shale sites. Isopleths of concentrations for some of the pollutants and averaging times are shown in Figure 16-2 through 16-5. Tables 16-14 and 16-15 summarize model results for the TOSCO II process and give background concentrations, air quality standards, and the level of control required to meet each standard. Background concentrations

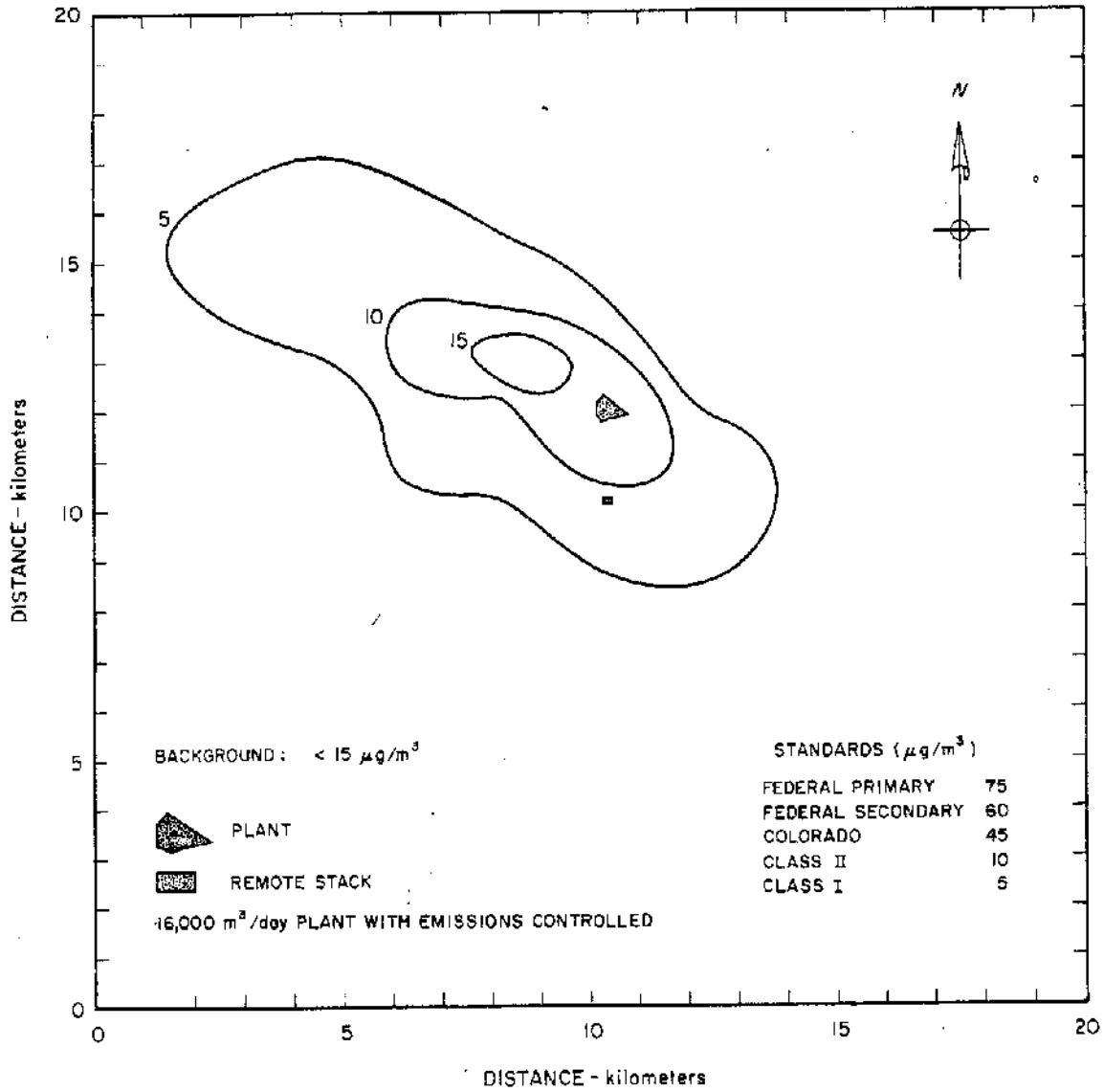


FIGURE 16-2. ANNUAL AVERAGE PARTICULATE CONCENTRATION ($\mu\text{g}/\text{m}^3$)
 FOR A TOSCO II OIL SHALE PLANT USING GRAND JUNCTION,
 COLORADO METEOROLOGY

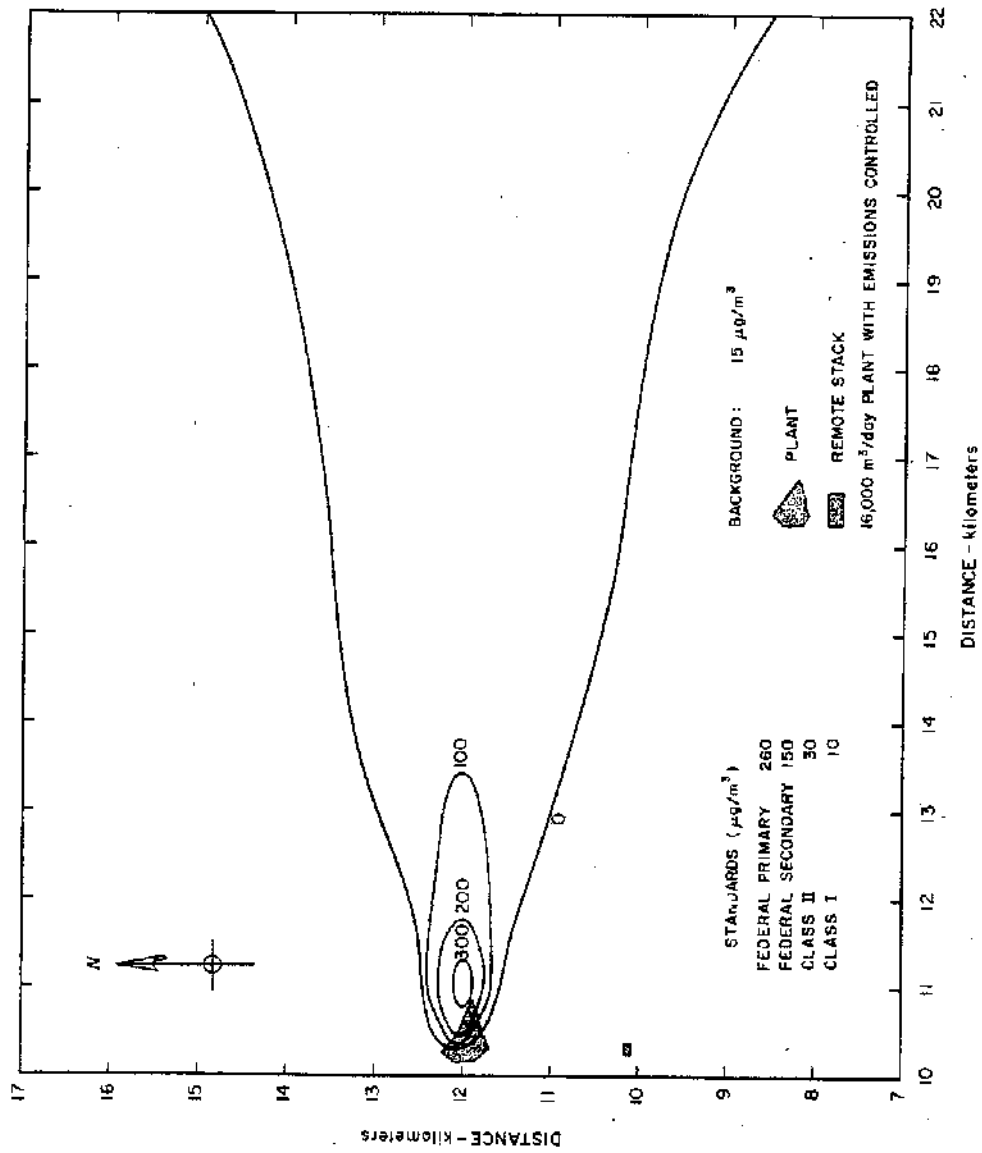


FIGURE 16-3. 24-HOUR WORST CASE AVERAGE PARTICULATE CONCENTRATION ($\mu\text{g}/\text{m}^3$) FOR A TOSCO II OIL SHALE PLANT UNDER CONDITIONS OF NEUTRAL STABILITY AND A WEST WIND OF 1.5 m sec^{-1}

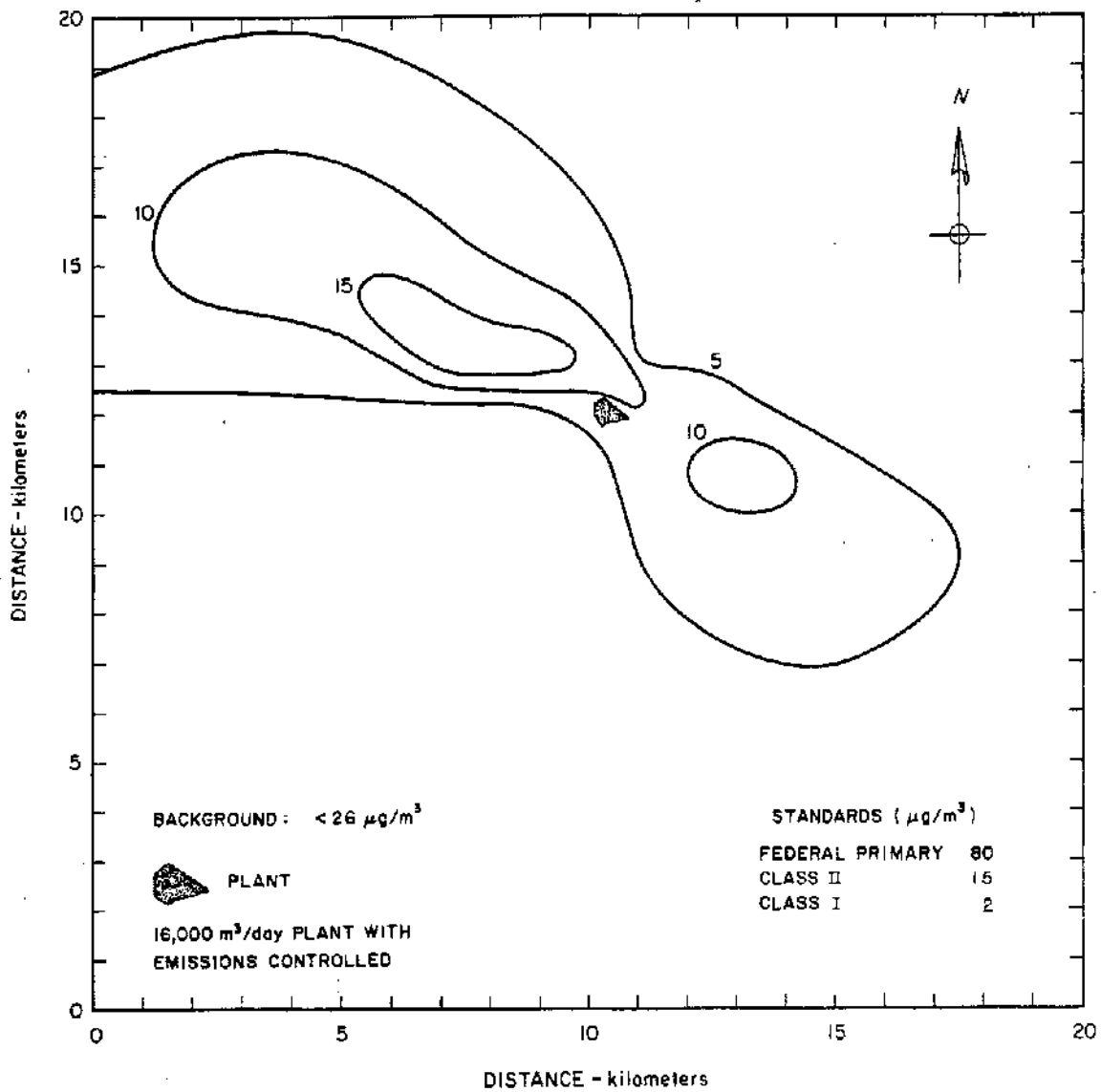


FIGURE 16-4. ANNUAL AVERAGE SO₂ CONCENTRATION ($\mu\text{g}/\text{m}^3$) FOR A TOSCO II OIL SHALE PLANT USING GRAND JUNCTION, COLORADO METEOROLOGY

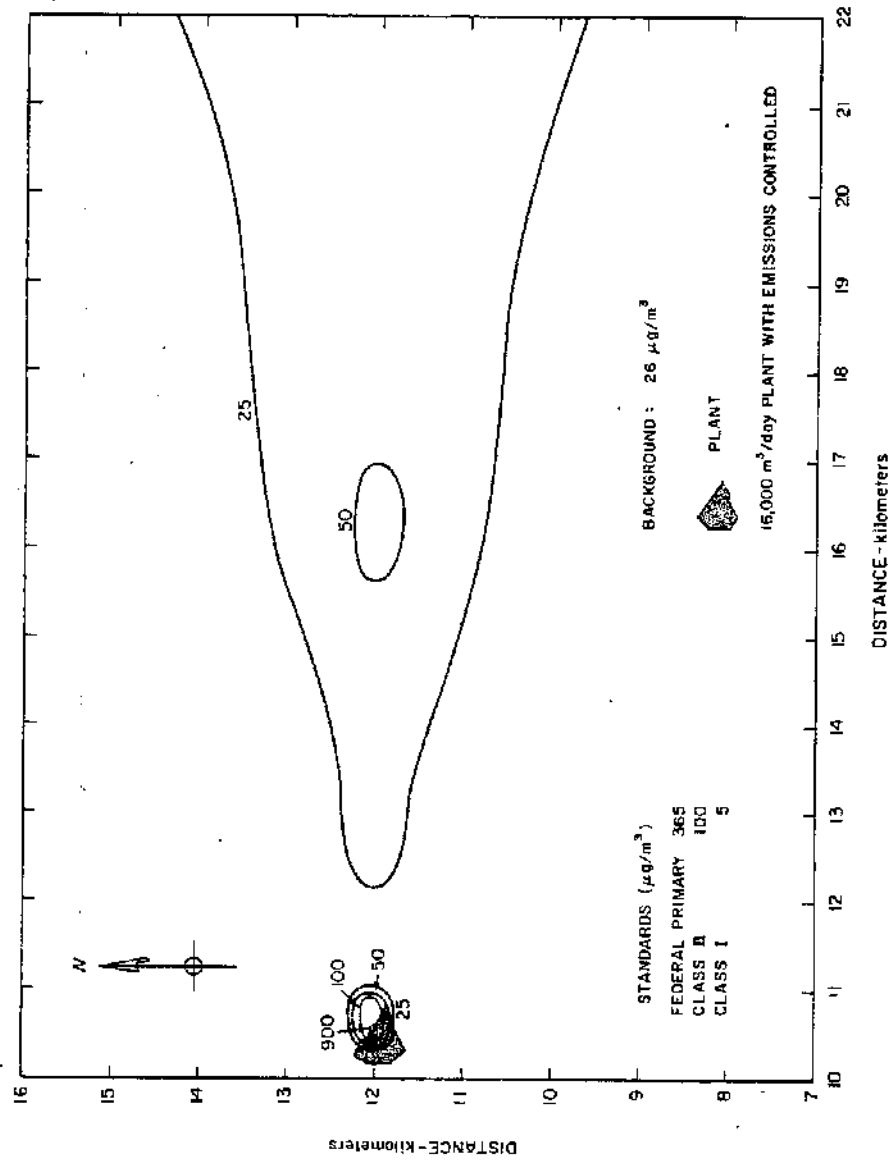


FIGURE 16-5. 24-HOUR WORST CASE AVERAGE SO_2 CONCENTRATION ($\mu\text{g}/\text{m}^3$) FOR A TOSCO II OIL SHALE PLANT UNDER CONDITIONS OF NEUTRAL STABILITY AND A WEST WIND OF 1.5 msec^{-1}

Table 16-14

CONTROL REQUIREMENTS BASED ON FEDERAL PRIMARY AND COLORADO AIR QUALITY STANDARDS
AND EMISSIONS FROM A 16,000-m³/day (100,000 B/D) TOSCO II PLANT, CONTROLLED

Pollutant	Averaging Period	Maximum Calculated ($\mu\text{g}/\text{m}^3$)	Background* ($\mu\text{g}/\text{m}^3$)	Standard ($\mu\text{g}/\text{m}^3$)		Control Required† (percent)	
				Federal Primary	Colorado‡	Federal Primary	Colorado
Particulates	1 yr	15	< 15	75	45	None	None
	24 hr	200	15	260	150	None	25
SO ₂	1 yr	18	< 26	80	--	None	--
	24 hr	51	26	365	15	None	99+§
HC	3 hr (6-9 AM)	11	--	160	--	None	--
NO _x	1 yr	23	--	100	--	None	--

*Based on preliminary Colony Development Operation data. Current measurements suggest that the 26- $\mu\text{g}/\text{m}^3$ value is too high.

†Control required in addition to the best available as specified in Section B.

‡Standards for nondesignated areas of Colorado. The 24-hr standard is not to be exceeded more than one day per year.

§Background concentrations alone may exceed standard.

Table 16-15

CONTROL REQUIREMENTS BASED ON FEDERAL SECONDARY, CLASS I AND CLASS II AIR
 QUALITY STANDARDS AND EMISSIONS FROM A 16,000-m³/day (100,000-B/D)
 TOSCO II PLANT, CONTROLLED

Pollutant	Averaging Period	Maximum Calculated (µg/m ³)	Background* (µg/m ³)	Standard (µg/m ³)		Control Required† (percent)			
				Federal Class I	Federal Class II	Federal Class I	Federal Class II	Federal	Secondary
Particulates	1 yr	15	< 15	5	10	67	33	None	
	24 hr	200	15	10	30	95	85	32	
SO ₂	1 yr	18	< 26	2	15	89	17	--	
	24 hr	51	26	5	100	90	None	--	

*Based on preliminary Colony Development Operation data. Current measurements suggest that the 26-µg/m³ value is too high.

†Control required in addition to the best available as specified in Section B.

were taken from the results of monitoring conducted in the Colorado oil shale region for Colony Development Operation.¹⁸

In calculating the control requirements shown in Tables 16-14 and 16-15, background concentrations and concentrations resulting from oil shale operations have been considered together for the federal primary and secondary standards and for the Colorado standards. This has been done by subtracting the background concentration from the standard and computing the level of control needed so that the concentrations resulting from oil shale facilities do not exceed the remaining portion of the standard. When background concentrations equal or exceed a standard, the level of control has been specified as 99+ percent. Federal Class I and Class II standards are the so-called "nondegradation" standards; they refer to increases in concentrations and do not involve background concentrations.

The maximum calculated concentrations and the percent control requirements given in Tables 16-14 and 16-15 are not always the same as those that would be derived from a straightforward application of the calculated dispersion patterns such as Figures 16-2 through 16-5. Instead, the maximum concentrations used in Tables 16-14 and 16-15 reflect our judgment that only concentrations that occur over an appreciable area at some distance beyond the plant boundary should be taken as the basis for a requirement for additional emission control technology. A control requirement should not be based on a calculated concentration that occurs in the immediate vicinity of a relative low stack because in actual commercial operations any such problems would be solved by use of taller stacks.* Therefore, only concentrations that occur over areas

*The use of taller stacks referred to here concerns replacing relatively low (about 15 m) stacks with some of moderate height (about 30 m). The same logic does not apply to avoiding excessive ground level concentrations associated with tall (about 100 m) stacks. See the discussion of the stack height issue in Section E.

of at least 1 km² at least 1 km away from the plant are included in the control requirement calculations shown in Tables 16-14 and 16-15.

The judgment just described is of much greater significance for oil shale case than for coal liquefaction. Stack characteristics used in modeling of the oil shale plant emissions are those published by Colony⁴ as part of their plans for an actual facility. In the coal liquefaction case we have chosen reasonable but hypothetical, stack parameters for the modeling and have deliberately avoided the low (about 15 m) stacks that can cause anomalously high concentrations in the oil shale case.

Particulate emissions from the TOSCO II process described will produce concentrations that exceed all standards listed in Tables 16-14 and 16-15, except the federal primary and secondary air quality standards. Background concentrations for particulates and SO₂ were measured in the Parachute Creek area of the Colorado oil shale region by Colony Development Operation. The analysis of these concentrations¹⁶ revealed that the median of the 24-hour averages was about 15 µg/m³. The average annual background concentration is expected to be less than 15 µg/m³. The combination of background concentrations with plant-produced concentrations for those standards which are applicable leads to the conclusion that no additional control is needed to meet the federal primary 24-hour standard and the Colorado annual standard. The federal 24-hour secondary standard can be met with approximately 32 percent control of plant emissions. Approximately 95 percent control will be needed to meet the Class I 24-hour standard and 67 percent will be needed to comply with the Class I annual standard. The Class II 24-hour and annual standards require 85 percent and 33 percent controls, respectively.

Projected concentrations of SO₂ do not exceed the federal primary air quality standards nor the Class II 24-hour standards. Some preliminary measurements⁴ suggested a 24-hour average background concentration of SO₂ of 26 µg/m³. This is now known to be too high,⁵ but a revised measurement has not yet been published. The annual average is expected to be considerably lower. The addition of background concentrations to the calculated concentrations resulting from the plant is not sufficient to exceed the federal primary air quality standards. However, SO₂ concentrations from the plant exceed the stringent Colorado annual air quality standard, where 99+ percent control is required, since background concentrations alone may exceed the standard. The federal Class I annual and 24-hour standards can be met with 89 percent and 90 percent control, respectively. The Class II annual standard requires only 17 percent additional control.

No additional controls are indicated for NO₂ and HC in Tables 16-14 and 16-15. The calculated concentrations of these pollutants are well below the NO₂ and HC standards shown. However, as mentioned above, no analyses of photochemical oxidant concentrations have been made.

3. Modeling an H-Coal Syncrude Plant

The Powder River Basin of Wyoming was selected for modeling the air pollution from plants producing synthetic crude oil from coal on the basis of physical, economic, and political availability of large blocks of coal, and the H-Coal process has been selected on the basis of (1) a relatively well developed technology, (2) high yield of a liquid product, and (3) availability of process descriptions in the open literature.